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-17990

At the February 28, 2017 meeting of the Michigan Public Service Commission in Lansing, Michigan.

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

ORDER

I. HISTORY OF PROCEEDINGS

On March 1, 2016, Consumers Energy Company (Consumers) filed an application seeking authority to increase rates charged to its 1.8 million retail electric customers for the generation and distribution of electricity, and for other regulatory approvals. The rate increase sought in this proceeding is based on the company's projections for relevant items of investment, expenses, and revenues for a test year covering the 12-month period from September 1, 2016, to August 31, 2017. Consumers averred that, without rate relief, the company will experience a jurisdictional electric revenue shortfall of $225 million, on an annual basis, during the test year.

Consumers explained that the largest portion of its requested relief, approximately $161 million, or 72%, is related to investments in system reliability, environmental compliance, and technology. The company contended that, over the next decade, it plans to invest over $10 billion in Michigan to maintain and improve utility infrastructure and provide valuable customer service. According to Consumers, capital expenditures for environmental, legal, and safety-related investments in electric utility generation and distribution assets are required. Consumers also asserted that continued technological improvements, such as its advanced metering infrastructure (AMI) project, are reasonable and necessary. Further, Consumers claimed that additional operations and maintenance (O&M) expenditures are necessary to improve the reliability of service to its customers, facilitate convenient customer payment options, fund employee incentive compensation, and promote economic development.

Consumers also stated that it is requesting rate recovery for the revenue requirements associated with two programs to be offered during the test year. First, Consumers proposed $2.9 million for a demand response (DR) program that will assist business customers in establishing a demand reduction plan at their facilities and will compensate participating customers for capacity provided during DR events. Consumers' second program involves the installation of plug-in electric vehicle (PEV) infrastructure over a period of two to three years in select high-traffic areas in the Lower Peninsula of Michigan.

Consumers requested approval of two revenue adjustment mechanisms. First, Consumers conditionally proposed a symmetrical "Revenue Adjustment Mechanism" (RAM) that shall be approved by the Commission only if legislation authorizing RAMs for electric utilities is enacted during the pendency of the instant case. Application, p. 5. The company stated that the proposed RAM compares, by rate class, nonfuel rate revenues approved in the most recent proceeding to the nonfuel revenue generated through actual sales for the period of time under evaluation. *Id.*

The second mechanism proposed by Consumers is an "Investment Recovery Mechanism" (IRM). Consumers explained that the IRM provides recovery of the company's incremental 2017, 2018, and 2019 capital investments, beyond investments incorporated in rates through the end of August 2017, associated with specific distribution, generation, and environmental compliance programs. Application, p. 6. Consumers asserted that the proposed IRM could extend the time period between rate case filings "by allowing for an early review of the next three years of the Company's capital investment plan." *Id*.

Consumers proposed that the rates established in this case include an authorized rate of return on common equity (ROE) of 10.7%, and reflect an overall rate of return on total rate base of 6.27%. Consumers stated that the requested returns reasonably balance the interests of customers and investors.

In order to establish rates equal to the cost of providing service to each customer class, Consumers contended that the Commission should revise the production cost allocation method to 4 coincident peak, 100% demand (4CP 100) and allow the company to update its intersystem sales allocator from a capacity allocator to an energy allocator.

In addition to rate relief, Consumers proposed a variety of revisions to its electric rules, regulations, and tariffs, generally described in paragraphs 15 and 17 of its application. In paragraphs 18 and 19 of its application, Consumers requested approval of various forms of accounting authority.

According to Consumers, the net impact of all matters to be considered in this proceeding supports the company's request for rate relief of $225 million. Consumers maintained that absent rate relief in this amount, the company will experience revenues so low as to deprive it of a reasonable return on its investments in violation of the federal and state constitutions.

A prehearing conference was held before Administrative Law Judge Dennis W. Mack (ALJ) on April 12, 2016. At the prehearing conference, the ALJ granted petitions to intervene filed by the Michigan Department of the Attorney General (Attorney General), the Association of Businesses Advocating Tariff Equity (ABATE), the Michigan State Utility Workers Council, Utility Workers Union of America, AFL-CIO, ChargePoint, Inc. (ChargePoint), The Kroger Company (Kroger), Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club (together, MEC/NRDC/SC), Hemlock Semiconductor Corporation (Hemlock), Energy Michigan, Michigan Cable Telecommunications Association, the Midland Cogeneration Venture Limited Partnership, and Michelle Rison and the Residential Customer Group (together, RCG). The Commission Staff (Staff) also participated. During the prehearing, William Malcolm, Senior Legislative Representative – State Advocacy and Strategy for AARP, Inc., provided comments pursuant to Mich Admin Code, R 792.10413. Thereafter, the ALJ approved a schedule for the remainder of the proceedings that was agreed to by the parties in attendance.

The ALJ denied a petition for intervention, along with a request for a declaratory ruling, filed by Phil Forner. Mr. Forner appealed, and the Commission granted his application for leave to appeal on May 20, 2016. In the order, the Commission affirmed the ALJ's ruling, stating that it has repeatedly found that the issues raised by Mr. Forner are not proper for a general rate case proceeding and that the Court of Appeals has upheld this determination on appeal.

Subsequent to the prehearing, the ALJ granted petitions to intervene filed by the Environmental Law and Policy Center,[1] and Wal-Mart Stores East, LP, and Sam's East, Inc. (together, Wal-Mart). The ALJ entered a protective order on June 7, 2016, finding that certain

[1] Environmental Law and Policy Center did not participate further in the proceedings.

testimony and exhibits of the parties were confidential and should be entered under a separate record.

On July 14, 2016, Consumers filed the testimony of one witness and two exhibits in support of self-implementation of a $170 million annual revenue increase, through use of equal percentage increases to all retail rates, on and after September 1, 2016. In addition, consistent with the October 16, 2014 order in Case No. U-17598, Consumers intended to terminate the distribution bill credit effective with self-implementation on September 1, 2016.

On July 27, 2016, the ALJ conducted a hearing on the company's proposed self-implementation. Consumers, the Staff, and the Attorney General appeared at the hearing, however, only the company presented evidence. The parties declined to cross-examine the witness, and Consumers' testimony and exhibits were bound into the record. On August 3, 2016, Consumers filed a brief in support of its self-implementation request. Absent action by the Commission, on September 1, 2016, Consumers self-implemented a rate increase designed to produce additional annual retail electric revenues of $170 million above levels established by the November 19, 2015 order in Case No. U-17735 (November 19 order).

The evidentiary phase of the proceedings commenced on September 7, 2016, and continued through September 13, 2016. The ALJ granted Consumers' motion to strike portions of the Attorney General's direct testimony and two related exhibits, but denied two other motions to strike by Consumers and one motion to strike by the Attorney General. Timely briefs and reply briefs were filed.

On December 16, 2016, the ALJ issued his Proposal for Decision (PFD). Consumers, the Staff, the Attorney General, ABATE, ChargePoint, Hemlock, Kroger, MEC/NRDC/SC, and the RCG filed exceptions to the PFD on January 9, 2017. Replies to exceptions were filed by

Consumers, the Staff, the Attorney General, ABATE, ChargePoint, Energy Michigan, Hemlock, MEC/NRDC/SC, and the RCG on January 18, 2017. The record consists of 2,803 pages of transcript and 366 exhibits received into evidence.

II. LEGAL STANDARDS

In exceptions and replies to exceptions, the Attorney General presented, for the first time, arguments concerning the legal standard applied by Consumers. He states that the company, "seemingly ignores the legal standards that apply in general rate cases before the Commission and that it has the burden of substantiating and proving its proposals are reasonable and prudent." Attorney General's replies to exceptions, p. 2. The Attorney General asserts that Consumers' burden of proof is a preponderance of the evidence. He argues, "[e]ven if Consumers presents substantial evidence on an issue, that alone does not require the Commission to rule in its favor." *Id.*, p. 4. Therefore, the Attorney General requests that the Commission keep these "burdens and obligations" in mind when reviewing the company's requests. *Id.*

No party replied, and the ALJ did not address this issue. The Commission is mindful of the Attorney General's arguments and concerns, and notes that these issues were fully addressed in the January 31, 2017 order in Case No. U-18014 (January 31 order), pp. 8-9; the September 8, 2016 order in Case No. U-17895, p. 4; and the January 11, 2010 order in Case No. U-15768 *et al.*, pp. 9-10.

III. <u>TEST YEAR</u>

Consumers proposed using the 12-month period ending August 31, 2017, as the test year, and no party objected. Consumers began with historical data from calendar year 2014, which was then adjusted to reflect updated sales and projections of investment, expenses, and revenues. The ALJ recommended adopting this test year, and the Commission agrees.

IV. <u>RATE BASE</u>

A utility's rate base consists of the capital invested in used and useful plant, plus the utility's working capital requirements, less accumulated depreciation. In its application, Consumers projected a total electric rate base of $10,292,542,000 (excluding amounts associated with its DR and PEV programs), adjusted to $10,232,150,000 in the company's initial brief. The Staff calculated a rate base of $10,199,355,000 on a total company basis, and the Attorney General advocated a downward adjustment of $196,873,000 to the company's rate base. After making adjustments, discussed in more detail below, the ALJ recommended a total rate base of $10,217,181,000.

A. Net Utility Plant

1. Contingency Costs

Consumers initially requested contingency costs for electric distribution, compliance costs associated with fossil and hydro generation, information technology (IT), and its smart energy program. *See*, Exhibit AG-8; Exhibits S-10.4 and S-10.5. The Commission has determined that the total requested contingency amount was $37.559 million, of which $32.943 million is at issue here.

Consumers presented testimony regarding the appropriateness of including risk-based contingency expenses in project planning and described its approach for projecting contingency costs. According to Consumers, the projected contingency costs in this case are reasonable and prudent, and its position on this issue was unrefuted. 7 Tr 1630.

The Staff and the Attorney General challenged Consumers' request on grounds that the Commission has previously determined that, although contingency planning may be an acceptable budgeting strategy, it is not appropriate for ratemaking. The Staff argued that ratepayers may be required to pay for contingency expenditures that may not be incurred. And, the Staff was unable to determine if the expenditures are reasonable and prudent because the conditions preceding contingency are unknown. Similarly, the Attorney General argued that the Commission should exclude all forecasted capital expenditures that are attributed to contingency.

In rebuttal, Consumers argued that including contingency in project cost projections is an industry-accepted, well-established, project management methodology. Consumers claimed that because contingency costs are a proper component of projected costs, the Staff's and the Attorney General's rationales for excluding these costs potentially violate MCL 460.6a(1): "A utility may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges."

Consumers noted that, despite a disallowance for air quality control systems (AQCS) project contingency in Case No. U-17735, the contingency amounts associated with that project were necessary and spent. Thus, Consumers asserted, the Commission should approve all components of its projected test year capital project costs, including contingency costs. Consumers' initial brief, p. 27.

The ALJ concluded that MCL 460.6a(1) does not bar the inclusion of projected contingency costs in rates. The ALJ found that the company provided detailed information on the method used to arrive at the contingency costs and the projects to which they apply, referencing the November 19 order. He noted that no party took issue with the company's method for establishing contingency costs, or the amounts calculated. Accordingly, the ALJ recommended that the Commission reject the Staff's and the Attorney General's recommendation to exclude contingency costs. PFD, pp. 19-20.

In exceptions, the Staff contends that the ALJ misinterpreted the November 19 order. The Staff argues that the Commission "agree[d] with the Staff . . . that inclusion of such [contingency cost] items in rate base is not sound ratemaking practice . . . ." Staff's exceptions, p. 3, quoting the November 19 order, p. 11. (Emphasis omitted.) Thus, the Staff maintains, the Commission disallowed contingency costs in the company's last rate case not for lack of adequate explanation, but because it was not sound ratemaking practice. In addition, the Staff quotes the December 11, 2015 order in Case No. U-17767 (December 11 order), p. 19, where the Commission reasoned that "contingency budgeting is speculative and shifts all of the risk associated with that item onto ratepayers, allowing for a return of and on an investment that may never be made." The Staff also points to the December 9, 2016 order in Case No. U-17999 (December 9 order) where the Commission disallowed DTE Gas Company's (DTE Gas) contingency costs for the very same reasons.

Furthermore, the Staff argues that the absence of language specifically providing for recovery of contingency costs in MCL 460.6a(1) indicates that the Legislature never intended for such recovery. In contrast, the Staff asserts, there is express statutory language regarding recovery of contingency costs in power supply cost recovery (PSCR) proceedings in MCL 460.6j(6).

The Staff reiterates that contingency costs are undefined, may never be incurred, and are therefore unreasonable. The Staff asserts it is unfair to require ratepayers to pay these costs, thereby insulating investors from the risk of cost overruns, while allowing investors to reap the benefit of a return on these amounts. The Staff argues that Consumers provided no reason to part from the Commission's position on contingency costs, noting that if contingency is spent, the company may recover these costs in a future rate case.

Like the Staff, the Attorney General argues in exceptions that contingency costs are unlawful, not reasonable and prudent, and not permitted by the Commission. He reiterates that due to the uncertainty of these costs, it is neither fair nor reasonable to burden ratepayers on the "chance" the cost might be incurred. Attorney General's exceptions, p. 6. The Attorney General maintains that Consumers did not meet its burden of proving that the proposed contingency costs are reasonable and prudent, and therefore failed to present any evidence that would lead to a departure from the Commission's determinations in recent cases. MEC/NRDC/SC agree with the Staff and the Attorney General.

The RCG excepts to the ALJ's recommendation, and argues that "[t]he contingency expenditures asserted by CECO are not in reality valid *expenditures* which should be recognized in the cost of service for ratemaking purposes. In contrast, the asserted contingency expenditures are purely speculative or theoretical amounts designed to exaggerate CECO's rate request in this case." RCG's exceptions, p. 1. (Emphasis in original.) The RCG states that if the company is allowed contingency expenditures, it will reduce Consumers' incentive to realize productivity gains and obtain economic efficiencies, and to ensure that expenditures are reasonable and prudent. Finally, the RCG contends, contingency costs are not authorized by statute or case law and should be rejected by the Commission.

In reply, Consumers reiterates that contingency costs are reasonable and lawful. Consumers explains that "[w]hile the Company fully plans on expending the costs requested, as a general matter, there is no guarantee that the requested costs of any category of projected costs will be incurred exactly as projected. The fact of the matter is that the contingency costs at issue are projected and expected to be expended by the Company." Consumers' replies to exceptions, p. 2. (Emphasis in original.) Therefore, the company argues, contingency costs are a reasonable component of its projected costs, and should be approved.

Consumers further asserts that, pursuant to the Commission's directive in the November 19 order, it provided support for its projected contingency costs through unrefuted, expert analysis on the calculation of risk-based contingency expense in project planning. In addition, the company states, its evidence shows that including contingency in project cost projections is an industry-accepted, project management methodology.

Consumers disputes the Staff's argument that pursuant to MCL 460.6a(1), contingency costs are not, as a matter of law, recoverable. Rather, according to Consumers, contingency costs are a component of projected costs that may be recovered under the statute. The company further asserts that the Court of Appeals has affirmed the Commission's authority to approve recovery of a utility's contingency costs with respect to a certificate of necessity proceeding conducted pursuant to MCL 460.6s.

The Commission agrees with the Staff, the Attorney General, MEC/NRDC/SC, and the RCG that Consumers' projected contingency costs should be disallowed. Although Consumers argues that contingency costs are no different than other projected costs, the Commission disagrees. As the Commission has previously determined, "[b]ecause Michigan utilities are permitted to rely on fully projected test year costs and revenues, which already introduces a measure of uncertainty in the rate setting process, the Commission finds that it is far too speculative to add contingency amounts on top of that." January 31 order, p. 12. In addition, what distinguishes projected contingency costs from other projected costs is not only that these costs are speculative, but also, that the cost depends upon the occurrence of some future event outside of the utility's control. The question of whether projected contingency costs should be included in rate base thus requires a determination about who, the utility's investors or its ratepayers, should bear the risk that the contingent event may never occur. In four previous orders, the Commission has consistently answered that question by denying recovery of projected contingency costs. *See, e.g.*, November 19 order, December 11 order, December 9 order, and January 31 order.

Although the ALJ is correct that Consumers provided an explanation as to how it derived contingency costs, those findings are not dispositive. The ALJ appeared to rely on language in the November 19 order determining that the company in that case had failed to convincingly explain how the contingency amounts were arrived at, or to specify which projects included contingency amounts. However, the Commission agrees with the Staff, the Attorney General, and MEC/NRDC/SC that the Commission excluded contingency costs because including such costs is not sound ratemaking practice.

As the Commission has discussed previously, the inclusion of contingency costs allows the utility to receive a return of and on those costs to the detriment of ratepayers who may never benefit at all. In addition, if ratepayers were required to bear this risk, there would be no incentive for the utility to minimize projected contingency costs, but every incentive to inflate them. For these reasons, as well as those the Commission articulated in its previous orders, the Commission reaffirms its determination and disallows projected contingency costs totaling $32.943 million.

Contingency costs should also be considered in the context of the discussion in other sections of this order, where the Commission addresses the issue that the company has been authorized in prior rate cases to recover certain investments and expenses, but ultimately spent less than the Commission-approved amount. The Commission realizes that variations may arise for a particular cost category (*e.g.*, tree trimming, grid modernization) between the amount projected in the rate case application, the amount approved by the Commission, and the amount actually incurred. The variation may occur due to the company reprioritizing spending in response to changing conditions, as well as potential cost savings or efficiencies. Thus, lower or reprioritized spending may be reasonable and prudent.

However, the variation may also be caused by over-projected costs in the rate case application. When these variations remain largely unexplained and occur across numerous program or cost categories, it is a concern to the Commission as it seeks to ensure that utility rates are reasonable and prudent. This issue is additionally complicated by the fact that the Commission is unable to complete a long-term review of the manner in which the company executes its spending priorities due to the short duration between rate cases.

The Commission addresses the issue of underspending/over projections on an issue-specific basis according to the evidence put forward in this case. The goal is to not micro-manage the company's operations and allocation of resources, but rather to ensure that ratepayer dollars are spent on needed investments that will improve safety, reliability, and affordability.

Because contingency costs were the only disputed issue under coal combustion residuals (CCR), IT, and smart grid/AMI, these cost categories will not be addressed further.

2. Electric Distribution and Energy Supply Capital Expenditures

Consumers requested recovery of projected electric distribution capital expenditures as set forth in Exhibit A-16. According to Consumers, these projections are the investment levels necessary for new business, and to address customer reliability, modernize and implement system infrastructure improvements, replace assets in response to emergent demand failures, relocate electric distribution infrastructure, and for fleet and facility upgrades. 6 Tr 1126.

There are nine major programs within electric distribution capital expenditures: (1) new business; (2) reliability; (3) grid modernization; (4) capacity; (5) demand failures; (6) asset relocations; (7) electric operations other; (8) high voltage distribution (HVD) – transmission; and (9) electric business. 6 Tr 1126-1140. Consumers asserted that these capital expenditures, when combined with O&M expenses, address tree-related outages, equipment failures, and outages stemming from weather, which are the leading causes of customer outages on the company's electric system. Thus, it asserted that this level of expenditures will improve electric system reliability and enhance customer satisfaction through a reduction in the number of customer outages. The Staff and the Attorney General recommended downward adjustments to electric distribution capital expenditures in the areas of reliability, grid modernization, and capacity. These adjustments are discussed *ad seriatim*.

a. Reliability Program Capital Expenditures

Consumers' reliability capital expenditures include investments to install, upgrade, and rehabilitate low voltage distribution (LVD) lines, metropolitan underground systems, protective relay systems, HVD lines, and HVD and LVD substations. The specific projected expenditures are set forth in Exhibit A-16, line 2. The company contended that this funding level provides for the necessary line equipment rehabilitation and pole replacements, and will address repetitive outages. Such outages require investments in poles, conductor, and other facilities to improve reliability. 6 Tr 1128. Consumers asserted that the work on the LVD lines will include: (1) upgrading lightning protection; (2) replacing equipment that has reached the end of its useful life such as poles, cross-arms, switches, and overhead and underground conductors; (3) addressing areas that have experienced repetitive outages; and (4) sectionalizing. 6 Tr 1129.

Regarding the work on the LVD and HVD substations, Consumers identified the work as replacement programs for specific equipment such as oil circuit breakers, substation lightning arresters, and transformer bushings, as well as, complete substation rebuilds and protective relay replacements. 6 Tr 1129. For the HVD lines, the company listed overhead line rebuilds including conductor and structure replacements, pole-top rehabilitation including the replacement of cross-arms, lightning arrestors, switches and insulators, replacement of deteriorated underground lines, and installation of motor-operated air break devices to minimize customer outages and outage duration. Consumers stated that 50-70% of the company's major equipment is over 30 years old and approaching the end of its useful life. These expenditures will enable the company to aggressively replace outdated and deteriorating equipment, and to upgrade assets to reduce the number of outages due to deterioration and improve the company's distribution assets' ability to withstand storm activity. 6 Tr 1130.

The Staff proposed a distribution reliability spending amount of $84.758 million, which represented a $3.532 million reduction to Consumers' test year spending. 8 Tr 2578. The Staff contended that, after its last electric rate case, the company spent just 65% of the Commission-approved amount for reliability. Specifically, the Staff stated, Consumers failed to spend about $45 million on a number of pre-approved projects that would have addressed system deterioration, aging infrastructure, and improve system reliability. 8 Tr 2578.

The Staff also criticized the company's current practice of replacing all defective poles, instead of implementing a pole rehabilitation program, which may be the most cost-effective approach. 8 Tr 2579. Thus, the Staff recommended that Consumers file a report in future rate cases explaining any circumstances that cause spending deviations from amounts approved in the rate case, and information supporting the cost effectiveness of pole replacement versus pole rehabilitation. Staff's initial brief, pp. 28-29.

The Attorney General recommended that the Commission reduce the amount for distribution capital expenditures by $16.41 million for 2016. He argued that forecasted expenditures for 2016 seem out of line with the actual level of expenditures spent in 2015 and those forecasted for 2017 through 2019. 8 Tr 2321. Accordingly, the Attorney General claimed that Consumers did not provide sufficient explanation or support to justify an escalation of nearly $40 million in additional capital expenditures from 2015 to 2016, which is also nearly $25 million over the projected 2017 through 2019 levels.

The ALJ recommended that the Commission reject the Staff's adjustment to the test year projection for the reliability program and further concluded that a pole remediation program should not be required. He found that the Staff failed to consider the timing of the decision in Case No. U-17735, which led the company to spend conservatively in the event its full rate request was not granted. The ALJ also agreed with Consumers that the Staff and the company should discuss a pole remediation program outside the confines of a rate case. PFD, p. 13. The PFD did not address the Attorney General's recommended adjustment for projected expenditures in the company's reliability program. No party filed exceptions.

The Commission agrees with the Staff's and the Attorney General's arguments that the test year projections for Consumers' reliability program should be reduced. After a review of the record, the Commission finds compelling the Staff's testimony regarding the unreasonableness and imprudence of Consumers' projected expenditures, and adopts the Staff's $3.532 million reduction to the company's reliability program capital expenditures. The Staff first looked at Consumers' historical spending after its last rate case, and observed that the company underspent approximately $46 million of the Commission-approved test year amount of $130.771 million for its reliability program. The Staff explained that, after audit requests in the current rate case, the Staff was unable to locate the unspent funds. The company's sole response was that it placed a higher priority on spending in other capital programs that are primarily reactive based on customer requests, capacity issues, systems demands, and system conflicts. *See*, 8 Tr 2577; Exhibit S-9.0.

The Commission finds Consumers' explanations regarding past underspending troubling. The Staff noted that Consumers explained that the underspending was a result of its decision to prioritize reactive programs over the proactive reliability program. However, when Consumers explained its past underspending in its reactive capacity program, the company stated the underspending was due to its decision to prioritize spending in its reliability program. The Commission is concerned with the credibility of Consumers' position when it explains underspending in one program area by pointing to spending in another program area where it also underspent approved amounts. This inconsistency raises questions about the reasonableness and prudence of its projected reliability test year expense in this rate case. Because the evidence suggests Consumers did not spend the amount approved for the program in its last rate case, and could not accurately trace the funds, the Commission has serious doubts about the company's willingness to spend the projected expenditures on its reliability program during the test year in this rate case.

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

Consumers also failed to establish the reasonableness of its spending in this area. The Staff noted that a significant portion of the company's projected expenditures are for pole replacement. The Staff stated that in 2015, the company spent $44.5 million on planned replacements of 6,103 distribution poles, which accounted for approximately 65% of the entire reliability program spend in 2015. The Staff asserted there was no evidence showing that utility pole failures are significant contributors to reliability concerns in the service territory. The Staff also noted that, although nearly a quarter of the entire distribution capital spend for 2015 was committed to utility pole replacement, Consumers has not provided a benefit/cost analysis that justifies the necessity of pole replacement compared to remediation, nor has the company provided insight into pole failure rates and causes of pole failures in the service territory. 8 Tr 2577-2579.

Nevertheless, the Commission finds, as it did in DTE Electric Company's (DTE Electric) most recent rate case, that Consumers is faced with significant investments in the coming years to address aging infrastructure and the need to incorporate advanced technologies into its distribution system. "[I]n order to properly evaluate these investments, and provide a greater level of regulatory certainty, the Commission finds that the rate case process would benefit from the company providing a more comprehensive, forward-looking capital investment and operations plan." January 31 order, p. 40. Thus, the Commission directs Consumers to produce and submit a five-year distribution investment and O&M plan that includes: (1) a detailed description, with supporting data, on distribution system conditions, including age of equipment, useful life, ratings, loadings, and other characteristics; (2) system goals and related reliability metrics; (3) local system load forecasts; (4) maintenance and upgrade plans for projects and project categories including drivers, timing, cost estimates, work scope, prioritization and sequencing with other upgrades, analysis of alternatives (including AMI and other emerging technologies), and an explanation of how they will address goals and metrics; and (5) benefit/cost analyses considering both capital and O&M costs and benefits.

As the Commission explained in the January 31 order, p. 41:

> A plan of this nature would increase visibility into the system needs and facilitate review by the Staff, other parties, and the Commission outside the contested rate case process. The Commission does not expect to formally "approve" the plan, but sees value in having a more thorough understanding of anticipated needs, priorities, and spending. The Commission therefore directs the Staff to work with the company to address clarifying questions on the plan framework . . . .

The Commission further directs Consumers to submit a draft plan to the Staff by August 1, 2017, and meet with the Staff to complete a final five-year distribution investment and maintenance plan to be submitted by January 31, 2018.

With respect to the Staff's and the Attorney General's request that the Commission order Consumers to provide a detailed benefit/cost analysis in its next rate case, the Commission declines to approve this request because the information sought is duplicative in light of the company's required five-year distribution plan filing.

b. Capacity Program Capital Expenditures

The Staff recommended that the Commission approve a distribution capacity capital expenditure amount of $45.690 million, a $10.585 million reduction to Consumers' proposed expense. The Staff argued that its level of spending is more appropriate given the company's historical spending variations and the lack of evidence supporting test year projections. Staff's initial brief, pp. 39-40. The Staff asserted that, after Consumers' last rate case, the company only spent $45.9 million of the approved $52.5 million test-year spending. The Staff disputed Consumers' claims that the underspending resulted from a prioritization of reliability spending and noted that reliability spending was over $50 million below the approved amounts. The Staff further noted that it is unclear to which program Consumers reallocated this funding. The Staff requested that future capacity project development include an analysis showing that current DR programs cannot alleviate demand prior to approving substation, transformer, and line capacity increases. 8 Tr 2599.

Consumers presented various arguments responding to the Staff's requested adjustment, explaining that historical spending is not an accurate indicator of future capital expenditures. Consumers also explained the benefits of the programs that the Staff targeted in its downward adjustments.

The ALJ agreed with the Staff's proposed adjustment and recommended the Commission adopt $45.69 million for capacity capital expenditures. Specifically, the ALJ was concerned that approximately $13 million was not spent as authorized in the last electric rate case and that the Staff was unable to review the 2017 projects that the company ultimately selected. Because the company failed to provide information necessary to determine whether the projected test year spending amount was warranted, the ALJ recommended the Commission accept the Staff's adjustment for this program.

Consumers takes exception, reasserting that the Staff's proposed adjustment relied on an invalid analysis resulting in unreasonable capital investment levels. Consumers reiterates that the Staff inappropriately attempted to portray capacity expenditures in a vacuum and that the Staff failed to evaluate the reasonableness of the program or its many benefits to customers. Consumers again disputes the Staff's comparison of preliminary spending to the amounts the Commission approved for this program in the last rate case.

The company urges the Commission to more thoroughly analyze these expenditures while acknowledging that Consumers must balance rate relief with expenses, sales, and other business needs. The company explains why historical spending patterns are not an accurate indicator of the reasonableness of its projected expenditures. Again, Consumers argues that the Commission's order in the last rate case was not issued until halfway through the projected test year, leaving the company guessing about the level of rate relief that would ultimately be approved. Consumers reiterates that the Staff's reduction can be attributed to the fact that the Staff based its analysis on a preliminary period that did not show later higher spending levels. And, the company asks the Commission to consider those programs in the last rate case where its spending exceeded Commission-approved amounts.

Finally, Consumers disagrees with the Staff's argument that it failed to provide the information necessary to determine that the projected distribution capacity amounts are warranted. Consumers points to evidence showing that investments were necessary to ensure that the HVD electric system is capable of serving forecasted electric peak demand with all HVD facilities in service, that single facilities of this system could be taken out of service during non-peak demand periods for maintenance and construction without loading remaining HVD facilities above emergency ratings or serving customers with unacceptable low voltage, and to fix LVD system overloads and low voltage occurrences after they occur. The company also refers to testimony explaining its various LVD and HVD substation and distribution line projects.

The Staff replies that Consumers never substantiated its claim that it prudently reallocated underspent amounts to other capital programs across the business. The Staff therefore urges the Commission to give no weight to this assertion. According to the Staff, although the company presented a list of 12 major projects on the HVD and LVD system, Consumers failed to provide a detailed scope of work or a cost estimate associated with any of the projects. The Staff argues that it is impossible to translate vague project descriptions into future revenue requirements or to evaluate the reasonableness of the projection. Absent tangible evidence supporting the projected spending plan for the test year in the capacity program, the Staff asserts that it is unreasonable to adopt the company's test year capacity expenditures. Instead, the Staff urges the Commission to adopt the PFD because it represents the most reasonable approach to setting rates.

The Commission finds the ALJ's findings and conclusions well-reasoned and therefore adopts his recommended adjustment to the test year spending for Consumers' capacity program. The Commission agrees with the ALJ's conclusion that Consumers' underspending in the last rate case, and the inability to carefully review the 2017 projects, are a concern. Moreover, the Commission agrees that Consumers failed to provide sufficient information to determine whether the projected test year spending amount was warranted.

c. Grid Modernization Program Capital Expenditures

The Staff proposed that the Commission approve test year spending of $40 million for grid modernization, reducing capital expenditures in this area by $29.219 million from the amount

Consumers proposed. The Staff pointed out that during the company's last test year, Consumers only spent 47% of the approved $30 million for the grid modernization program. 8 Tr 2586. The Staff argued that Consumers failed to justify additional millions for a program where such underspending has occurred. Further, the Staff asserted, the recommended $40 million will ensure that ratepayers realize AMI benefits by allowing investment in distribution supervisory control and data acquisition (SCADA), distribution management system, and grid analytics programs. The Staff advocated limited piloting of distribution automation, system conditioning, and volt/volt-ampere reactive optimization and proposed requiring Consumers to file a grid modernization report that outlines the scope of deployment, as well as, the benefits and costs of these projects before the Commission approves future investments. 8 Tr 2582.

The Attorney General recommended that the Commission remove $34.3 million from 2016 and $42.786 million from the company's projected amount for the eight months in 2017. He also requested that the Commission direct Consumers to present a more thorough and complete benefit/cost analysis in the company's next rate case to support the continuation of the grid modernization program. Attorney General's initial brief, pp. 57-58. He reasoned that the company failed to support and explain the assumptions used to justify the projected financial benefits from the program.

The ALJ found the Staff's $40 million test-year budget for grid modernization reasonable. The ALJ cited the Staff's claim that the company has not provided sufficient information regarding program spending, or the reason that the spending was 50% under the level approved in Case No. U-17735. Without this information, the ALJ found the Staff's recommended test year amount to be appropriate. The ALJ further found reasonable the Staff's request for specific information regarding the scope, benefits, and costs of each project in the spending plan through

2019, along with pilot results. Thus, the ALJ recommended that the Commission require that Consumers prepare and file a report on the grid modernization program consistent with the Staff's testimony on this issue. PFD, p. 16.

In exceptions, Consumers reiterates that the Staff's proposed adjustments rely on an invalid analysis, the Staff took an overly-narrow view of the company's expenditures, the Staff inappropriately compared forecasted expenditure amounts to projected and actual expenditure amounts from the company's last electric rate case, and the Staff failed to evaluate the reasonableness of its projected distribution capital programs in this case. Consumers again argues that, because of the timing of the order in its last rate case, the company took a conservative approach to spending, unsure of the level of rate relief that the Commission would ultimately approve. The company further disputes the Staff's use of an analysis that is based on a preliminary period that did not include a final determination of actual spending levels.

Consumers likewise disagrees with the Staff's claim that it has not provided sufficient information regarding the projected expenditures presented in this case. The company cites testimony that explains the purpose of grid modernization and the ways in which specific projects and technologies benefit customers. 6 Tr 1131-1137. Consumers refers to its discovery and audit responses as providing further information about its grid modernization effort and also points out that its analysis demonstrates a positive net present value (NPV) for the program investments. Consumers also urges the Commission to reject the recommendation for additional grid modernization reporting, noting that the company has met with the Staff to discuss the program and intends to continue such discussions going forward, obviating the need for additional reporting.

The Staff replies that the Commission should reject Consumers' argument that it provided evidence to support the expenditures for this program, countering that the company provided nothing more than a glossary of grid modernization terms and definitions. The Staff asserts that these definitions failed to provide a basis for determining that the dollar amounts requested in the projected test year are reasonable and prudent. Staff's replies to exceptions, pp. 9-10. Specifically, the Staff contends that Consumers did not provide sufficient evidence to show that the operational benefits the company claims will result from these projects will actually materialize. In addition, the Staff asserts that the company failed to delineate the type of assets to be installed, their costs, or their locations.

The Staff reiterates that Consumers is requesting additional expenditures on the heels of its last rate case, where it only spent $14 million of $30 million approved for this program. Thus, the Staff argues that the ALJ appropriately supported the Staff's proposed spending.

The Attorney General similarly urges the Commission to adopt the PFD for the reasons he provided in his initial brief.

The Commission finds the PFD well-reasoned and agrees that the record supports the Staff's proposed test year spending. The Commission directs Consumers to coordinate with the Staff on continued reporting in this area as part of the new distribution system plan discussed *supra*. And, as previously explained, the Commission rejects Consumers' argument that its underspending in this particular area was necessitated by the timing of the last rate order. The Commission issued a timely order in the company's last rate case, and it was the company's decision to not follow through on planned investments. Thus, it was reasonable for the Staff and the Attorney General to consider the discrepancy in approved, versus actual, spending on an historical basis.

3. Fossil and Hydro Generation Expenditures

Consumers' Revised Exhibit A-45 details the capital expenditures proposed for fossil and hydroelectric generation for the test year in the amount of $452.4 million for 2014, $538 million for 2015, $370.8 million for 2016, and $165.1 million for the eight months ending August 31, 2017. According to Consumers, the major drivers of capital expenditures for generating plants are compliance with Environmental Protection Agency (EPA) regulations and maintaining plant reliability. 7 Tr 1601. The company's initial brief and testimony provide details of both categories of capital expenditures which will not be repeated here. *See*, 7 Tr 1604-1616; Consumers' initial brief, pp. 17-27. Consumers argued that its proposed fossil and hydro generation capital expenditures are reasonable and prudent and requested that the Commission approve these amounts.

The contested capital expenditures and related issues in this category include compliance costs for the EPA's Steam Electric Effluent Guidelines (SEEG), costs for hydro generation projects, "avoidable" costs associated with the D.E. Karn 1 and 2 and J.H. Campbell 1 and 2 units (Medium 4 Units), and the need for a retirement analysis of those four units. These issues are addressed below.

a. Steam Electric Effluent Guidelines Capital Expenditures

Consumers sought recovery for the segregation of low volume wastewater and other non-bottom ash transport process water streams from the bottom ash system. The company also requested recovery for coal pile runoff modifications required to ensure the discharge quality of the waste stream. In addition, Consumers anticipated commencing the design and engineering of closed loop recirculating systems with wastewater treatment (WWT) to comply with SEEG at the Karn and Campbell facilities. 8 Tr 1733-1734. Consumers presented the costs for SEEG compliance in its Revised Exhibit A-24. Additionally, the Staff's Exhibit S-8.4 shows SEEG expenditures by category, with $1.263 million projected for coal pile runoff, and another $4.909 million projected for WWT design and engineering.

In addition to the $9,000 disallowance for SEEG contingency costs discussed above, the Staff proposed removing $2.455 million for SEEG. Specifically, the Staff proposed removing half of the $4.909 million in WWT design and engineering. The Staff explained that this reduction is based on the absence of any clear link between the projected expenditures and the supporting cost estimates, the presentation of a compliance timeline that does not match the one Consumers presented to the Michigan Department of Environmental Quality (MDEQ), and the fact that the company's actual capital expenditures for SEEG in prior rate cases were significantly less than the amount authorized. The Staff acknowledged that, although its proposed reduction is not tied to any specific numerical values, its recommended 50% reduction is a conservative estimate. The Staff further pointed out that the reasons for the reduction do not present precise numerical values from which the Staff could calculate its recommendation. In addition, the Staff recommended that Consumers be directed to meet with the Staff, biannually, to discuss the status of environmental regulations and the company's compliance efforts.

Consumers disagreed with the Staff's claim that the company did not provide cost estimates that were sufficiently detailed, citing the company's explanation of associated costs in discovery. Consumers argued that the costs the Staff requested that the company segregate represent functions that are, in fact, combined. In addition, Consumers suggested that the mere fact that MDEQ may give the company more time to achieve SEEG compliance does not justify the Staff's reduction in WWT design and engineering for the test year. Consumers' initial brief, p. 29. Thus, the company argued that delaying the expenditures would be imprudent. Additionally, Consumers pointed to testimony that explained the misalignment between projected and actual SEEG expenditures in past rate cases. Consumers criticized the Staff's recommendation as arbitrary and devoid of any underlying analysis, and urged the Commission to reject it.

The ALJ concluded that the Commission should reject the Staff's proposed adjustment but should approve the Staff's request for biannual meetings to provide updates on all environmental projects and the status of pending or proposed environmental regulations affecting those projects. PFD, p. 22. Specifically, the ALJ found that the record shows that Consumers supported its projected expenditures for WWT design and engineering. The ALJ noted that the company claimed that it intends to fully comply with SEEG by the end of 2021, and therefore, it is necessary to start the design and engineering work. The ALJ also found persuasive Consumers' claim that past underspending in this area was due to delays in the promulgation of the SEEG. Thus, the ALJ found Consumers' projected test year expenditure of $4.909 million for WWT design and engineering to be reasonable and prudent.

In exceptions, the Staff disputes that Consumers has substantiated its projected expenditures for SEEG. The Staff reiterates that the company failed to provide a detailed financial crosswalk between the numbers Consumers provided in Exhibit A-121 and the numbers in revised Exhibit A-24. The Staff maintains that in order to conduct a reasonableness and prudency review, the Staff needs to be able to trace the numbers in Exhibit A-24 back to their sources in Exhibit A-121.

The Staff also disagrees with the ALJ's wholesale adoption of Consumers' argument that it would be imprudent not to proceed with the WWT design and engineering work during the test year. The Staff urges the Commission to consider that Consumers' letter to MDEQ stated that it intended to avoid major SEEG expenditures until the 2021-2023 time period. The Staff additionally asks the Commission to recall that, in the last two electric rate cases, the company vastly overestimated its SEEG capital expenditures for 2014 and 2015, and that many of the SEEG activities for which Consumers seeks recovery in this case are similar to the activities described in those prior cases. Staff's exceptions, p. 13. Finally, the Staff notes that Consumers admitted it will suspend SEEG spending after the test year if MDEQ extends the deadline.

MEC/NRDC/SC argue in exceptions that SEEG expenditures should be excluded because the record demonstrates that these costs are, or should be, avoidable in the event that some or all of the Medium 4 Units are retired in 2021. They note that, in the documents presented to MDEQ, Consumers projected no SEEG activities to occur in 2016 through 2019, and that the majority of activities, including WWT design and engineering, will occur from 2020 to 2023. They further argue that some SEEG compliance costs will be stranded if one or more of the Medium 4 Units is retired. Thus, MEC/NRDC/SC argue that it is not prudent for ratepayers to provide rate recovery of the funds now; rather, Consumers can request recovery of reasonable and prudent expenditures in a future rate case.

Consumers replies that the Commission should reject the Staff's and MEC/NRDC/SC's arbitrary and unsupported reductions in SEEG costs. The company first argues that, contrary to the Staff's claim, the costs of wastewater segregation and the costs of WWT engineering cannot be segregated because these functions are combined. Consumers notes that the detailed costs for all components of SEEG compliance are set forth in confidential Exhibit A-121.

Consumers argues that it presented testimony that the cost estimates set forth in Exhibit A-121 form the basis for the SEEG costs included in revised Exhibit A-24. Consumers urges the Commission to reject the Staff's argument that it needs a financial "crosswalk" in order to recommend recovery of costs associated with SEEG compliance. The company notes that no witness presented evidence that the costs incurred to achieve SEEG compliance are unnecessary or unreasonable.

Regarding the letter to MDEQ requesting an extension of the compliance deadline, the company notes that the extension has not been approved. Thus, according to Consumers, it would be imprudent to delay implementation of the design and engineering of the WWT systems. Consumers asks the Commission to reject the Staff's "wait, hope, and see" strategy of delaying compliance with currently-effective environmental regulations. Consumers' replies to exceptions, p. 19. The company argues that its strategy is reasonable and necessary to meet current regulatory requirements, and the Commission should approve the costs of executing that strategy.

Consumers also urges the Commission to reject the Staff's argument that the company over-projected SEEG expenditures in previous rate cases. Consumers explains that its prior projections did not fully materialize as a result of changing regulations that were beyond its control.

The Commission considered the record, the parties' arguments, and the PFD, and agrees with MEC/NRDC/SC and the Staff that Consumers' proposed SEEG expenditures should be reduced. Consumers' letter to MDEQ raises an issue of fact regarding the company's intention to conduct WWT design and engineering studies during the test year. Specifically, in Exhibit MEC-52, a letter dated March 24, 2016, from Consumers to MDEQ presenting its timeline for SEEG compliance at the Karn and Campbell plants, Consumers lists the compliance activities to be completed before December 31, 2023. Due to the complexity of designing and installing new systems associated with SEEG, while also coordinating with compliance requirements of CCR, the Clean Power Plan (CPP), and other environmental and operational needs, Consumers seeks to avoid major SEEG expenditures until 2021-2023. Moreover, Table 2 of that letter shows that

Consumers does not intend to undertake any SEEG compliance activities from 2017 through 2019. This letter raises questions about the veracity of Consumers' testimony outlining a very different timeline for completion of SEEG activities. Given the conflicting evidence regarding Consumers' proposed timeline for SEEG compliance, the Commission is not persuaded that Consumers has met its burden of proving that the proposed expenditures will in fact be incurred before the end of the test year.

Moreover, the Commission finds compelling the Staff's arguments regarding Consumers' underspending for SEEG compliance in its previous rate cases. In Case No. U-17087, Consumers projected SEEG expenditures of $17.48 million for 2014, but the company only spent $1.39 million, or 7.9%, of the projected amount. *See*, Staff's initial brief, p. 18; 8 Tr 2566. In Case No. U-17735, Consumers projected SEEG expenditures of $7.062 million for 2015, but it only spent $1.053 million, or 14.9%, of that amount. *Id.*; 8 Tr 2566-2567. The Staff argues that the descriptions of those proposed expenditures are "very similar" to the studies, design, and engineering Consumers is proposing in this case. Although the company argued that the variability in spending was due to a changing regulatory landscape, the Staff argues that the company's testimony about these regulatory changes does not explain the over projections. Given the significant discrepancy between proposed and actual spending for SEEG compliance in successive rate cases, the Commission is persuaded that a more conservative approach is required. Accordingly, the Commission adopts the Staff's proposed 50% reduction in the amount of SEEG compliance expenditures, resulting in a downward adjustment of $2.455 million. Any additional reasonable and prudent expenditures for SEEG compliance may be recovered in a future rate case. The Commission also expects all future requests for Medium 4 Units to include NPV analysis of all incremental investments versus retirement.

The Commission adopts the Staff's recommendation that Consumers meet with the Staff biannually so that the company may keep the Staff apprised of pertinent developments and changes in the regulatory compliance landscape and compliance strategies.

b. Hydroelectric Generation Expenditures

The Attorney General proposed an $8.2 million reduction to Consumers' fossil and hydroelectric generation capital expenditures based on his conclusion that half of the company's projected hydro expenditures will not be incurred during the test year. According to the Attorney General, Consumers failed to provide work plans for most of the hydro projects; thus, he concluded, those projects will not be completed by the end of the test year. He further explained that the forecasted expenditures are very preliminary and that Federal Energy Regulatory Commission (FERC) approval for the projects is necessary. *See*, 8 Tr 2317-2330.

Consumers responded that the Attorney General provided no evidence to support his claim that the forecasted expenditures are very preliminary. Consumers further argued that its testimony provides a reasonable basis to approve its projected hydro expenditure amounts and requested that the Commission approve these expenditures.

The ALJ recommended rejecting the Attorney General's proposed reduction, finding that there was no evidentiary support underlying the Attorney General's claim that not all of the projects will be complete by August 31, 2017.

The Attorney General takes exception, arguing that the ALJ's conclusion ignores evidence and improperly shifts the burden of proof to the Attorney General. He argues that Consumers had the burden of proving by a preponderance of the evidence that its forecasted expenditures are tangible, reasonable, and likely to be incurred. The Attorney General maintains that Consumers failed to provide detailed costs by project. Conversely, the Attorney General argues, he provided evidence that the expenditures are estimates based on engineering studies that lack developed work plans approved by the FERC. Thus, the very preliminary status of the relevant projects call into question whether the costs will be incurred during the projected test year. Therefore, the Attorney General argues that Consumers failed to satisfy its burden of proving that the projects can be accomplished within the test year. He maintains that the recommended reduction of only 50% is generous given the lack of evidentiary support for the expenditures.

In replies to exceptions, Consumers disagrees that the ALJ shifted the burden of proof. The company argues that when the Attorney General asserted that the hydro projects will not be completed, or that expenses would not be spent during the test year, he was also obligated to support that position. Consumers contends that the Attorney General failed to provide adequate evidence to support his position and therefore urges the Commission to reject his proposed reduction.

The Commission finds the ALJ's findings and conclusions well-reasoned and adopts the ALJ's recommendation to reject the Attorney General's proposed reduction. The Commission finds that the Attorney General did not meet his burden of providing sufficient evidence in support of his vague assertion that Consumers will not incur the expenses during the test year. The Commission likewise rejects the Attorney General's argument that the ALJ improperly shifted the burden of proof. After Consumers provided support for its costs and concluded that the costs would be incurred during the test year, the burden shifted to the Attorney General to prove that Consumers would not, in fact, incur the costs during that time.

c. Medium 4 Units' Capital Expenditures

MEC/NRDC/SC criticized Consumers' proposal regarding estimated incremental generation and environmental compliance investments for the IRM period, noting that the company failed to show its proposed capital spending plan for the IRM period is prudent. Specifically, MEC/NRDC/SC argued that Consumers did not submit a current, or even recent, analysis showing that additional capital investment in continued operation of its Medium 4 Units beyond the test year is prudent. 8 Tr 2152. MEC/NRDC/SC further claimed that the preliminary analysis that Consumers provided indicates that the units are "economic losers on a long-term NPV basis." 8 Tr 2153. Therefore, MEC/NRDC/SC recommended that the Commission reject recovery of the proposed test year and IRM period capital spending on the Medium 4 Units because Consumers failed to demonstrate that the spending is just and reasonable. MEC/NRDC/SC further requested that the Commission require Consumers to present evidence in a future rate case that proposed spending on its Medium 4 Units is reasonable and prudent.

Additionally, MEC/NRDC/SC recommended that the Commission should require Consumers to produce, in a timely manner, a full and adequate analysis of the potential retirement of each of the Medium 4 Units to determine, on a unit-by-unit basis, the prudent disposition of each unit before the company commits to or incurs any post-test year spending that could be avoidable. This will ensure that any future spending plans are made with an understanding of the value and cost of each unit to customers so as to avoid unnecessary expenditures. *See*, 8 Tr 2154, 2164-2166.

In its initial brief, the Staff stated that, by and large, it agrees with MEC/NRDC/SC that Consumers should be required to perform a thorough analysis before seeking future recovery of expenditures on the Medium 4 Units. However, the Staff provided two modifications to MEC/NRDC/SC's witness' recommendation: (1) in addition to a 2021 retirement scenario, Consumers should include a 2023 retirement scenario; and (2) the analysis should be completed before Consumers files its next general rate case, and the study should be submitted as part of that filing. In addition, the Staff recommended that the Commission require the company to regularly meet with the Staff to discuss its environmental projects. Staff's initial brief, pp. 23-24; 8 Tr 2569-2570.

Consumers responded that it presented evidence that no test year capital expenditures would be avoidable by retiring the Medium 4 Units in 2021 because the company has already committed to the financial and contractual obligations required and planned for its 2017 investments in these units. Consumers' initial brief, p. 35; 7 Tr 1636. Further, the company argued that compliance with the Clean Water Act and SEEG requires Consumers to move forward with expenditures for these units. Thus, it asserted that delaying recovery of these costs would result in significant underfunding of the critical studies and initial steps to ensure future timely environmental compliance. 8 Tr 1746.

Consumers also disputed MEC/NRDC/SC's presumption that there may be avoidable capital expenditures during the test year. Consumers stated that the Medium 4 Units are critical base-load plants and therefore, MEC/NRDC/SC's proposal to reduce test-year expenditures is reckless because a retirement path would result in reduced unit reliability. The company cited testimony that it reached a crossroads in late 2011, regarding the continued operation of its Medium 4 Units and, after a thorough analysis, Consumers found that the units provide economic value to customers and concluded that environmental compliance was in the customers' best interest. Thus, it disagreed with MEC/NRDC/SC's conclusion that the company's preliminary evaluation mandates a 2021 retirement of the Medium 4 Units.

Consumers asserted that the preliminary analysis was not intended or designed to address avoidance of expenditures in anticipation of retirement in the period before late 2017 and early 2018. The company also explained the reasons no decision has been made on the retirement date(s) of these units. *See*, Consumers' initial brief, pp. 38-39. In summary, Consumers urged the Commission to reject MEC/NRDC/SC's recommended disallowances because they are based on a preliminary analysis that does not support a 2021 retirement, and because no costs included in the test year would be avoided even if the units were retired in 2021.

The ALJ recommended rejecting MEC/NRDC/SC's adjustment because they failed to identify which specific expenditures were avoidable or how these expenditures would not affect the facilities' operation if Consumers decides to retire them in 2021. PFD, p. 23. The ALJ further pointed out that Consumers provided detailed projected test year capital expenditures for the Medium 4 Units, and established that those expenditures are necessary to ensure the continued reliability of those facilities.

In exceptions, MEC/NRDC/SC request that the Commission reject the ALJ's findings because they are unsupported by the record, improperly shift the evidentiary burden to MEC/NRDC/SC, and fail to protect customers from spending that, they argue, is likely uneconomic and avoidable. They point out that although Consumers' application sought recovery of all of the projected capital spending for the Medium 4 Units through 2019, the company failed to provide any analysis regarding whether the spending was economically reasonable and prudent. For example, MEC/NRDC/SC assert, Consumers failed to mention the NPV analysis in its application that, MEC/NRCD/SC claim, shows that the 2021 retirement of the Medium 4 Units would be a lower-cost option for customers than continuing to operate the units through 2030.

MEC/NRDC/SC also argue that continued operation of some or all of the Medium 4 Units is likely to result in economic losses for customers, even in the near term, if Consumers spends significant amounts on capital and major maintenance for those units rather than putting them on a path to retirement in 2021. MEC/NRDC/SC assert that capital and major maintenance costs at these units could be avoided from 2017 through 2021 if all four units are scheduled for retirement at the end of 2021. Thus, MEC/NRDC/SC ask the Commission to order a pause in rate recovery until Consumers completes an evaluation of the 2021 retirement of the Medium 4 Units and the Commission reviews the evaluation.

On page 18 of its exceptions, the Staff asserts that it recommended in its initial brief that Consumers "be required to conduct an analysis comparing the benefits of continuing operation versus retiring early the Karn 1 and 2 and Campbell 1 and 2 units," and that the ALJ failed to address this recommendation. The Staff argues that such an analysis will provide useful information that could reduce the amount of unrecovered book value associated with retired units in the future.

Consumers replies that there is no statutory requirement that the Commission determine whether costs could be "avoidable" when determining whether rates are just and reasonable. Rather, the company explains, numerous Court of Appeals decisions have determined that the Commission's ratemaking authority is not limited to specific formulas or methodologies. Instead, Consumers argues, MEC/NRDC/SC have the burden of supporting their position and they failed to prove that the company's expenditures related to the Medium 4 Units were avoidable.

Regarding the preliminary early retirement analyses performed by the company in considering the long-term NPV of the Medium 4 Units, Consumers states that "MEC places much more weight upon the NPV Analyses than is warranted given the purpose and preliminary nature of the analyses. These analyses do not provide sufficient support to conclude that a 2021 retirement of one or more of the Medium 4 units would 'likely be beneficial to customers.'" Consumers' replies to exceptions, pp. 47-48. Consumers contends that there are several other additional analyses that are important in considering early retirement of the Medium 4 Units. *Id.*, p. 49.

In reply to the Staff's request that Consumers perform an analysis of the benefits/costs of continued operation of the Medium 4 Units, the company argues that the Staff's recommendation is premature and unnecessary in light of the uncertain status of the CPP. In addition, Consumers asserts that the Medium 4 Units "continue to operate reliably and provide value to the Company's customers and assist in ensuring the reliability of the entire Midcontinent Independent System Operator ("MISO") footprint." Consumers' replies to exceptions, p. 28. The company states that it will continue to keep the Staff apprised of pertinent developments and changes in the regulatory compliance landscape and compliance strategies. *Id.*

The company argues that, even in a 2021 retirement scenario, Consumers will continue to operate the units until 2021, and therefore capital investments are necessary to ensure safe and reliable operation. Consumers reiterates that it provided testimony supporting the proposed investments, discussing the benefits of the investments, and establishing their reasonableness.

The Commission agrees with the ALJ that MEC/NRDC/SC failed to specify the expenditures for the Medium 4 Units that they deem avoidable or how the expenditures would affect the facilities' operation if Consumers were to retire the Medium 4 Units in 2021. In contrast, Consumers met its burden of supporting projected costs and the benefits for the test year, rendering the costs reasonable. Thus, the Commission adopts the ALJ's recommendation to reject MEC/NRDC/SC's proposed disallowance.

Nevertheless, the Commission agrees that the company should submit a benefit/cost analysis for the Medium 4 Units. The regulatory, market, and technical underpinnings of Consumers' previous analyses of the Medium 4 Units have evolved significantly and the company's prior decision to keep the units running until after 2021 may no longer be economically justified. Therefore, the Commission directs Consumers to provide a detailed benefit/cost analysis regarding the retirement of the Medium 4 Units, as set forth by MEC/NRDC/SC and modified by the Staff, in its next rate case. In addition, the Commission finds that the company shall meet with the Staff biannually to discuss its environmental projects as set forth by the Staff in its initial brief and testimony.

4. Smart Grid/Advanced Metering Infrastructure Capital Expenditures

Consumers provided testimony that, of the $750 million total capital investment for the company's AMI program from 2007 through 2019, the electric portion of this investment is approximately $659.649 million. Of this, Consumers requested a total of $428,856,000 for AMI capital investments to be included in rate base through the test year. Consumers' initial brief provides a summary of the various benefits of its AMI program, and the company further argued that its request satisfies the NPV benefit/cost standard, is reasonable and prudent, and should be approved.

The Staff proposed a $10.047 million downward adjustment to Direct Load Administration (DLA) switches in these capital expenditures. The Staff's adjustment was based on its determination that, in connection with Commission-approved capital expenditures for DLA switches in Consumers' last rate case, the company installed none of the 8,300 switches proposed in 2015 and only six of those switches in 2016. As it did in the last rate case, the Staff again opposed recovery based on the company's failure to prove the functionality or usefulness of DLA switches in light of recent developments in direct load control. Staff's initial brief, p. 46. For these reasons, the Staff recommended that the company pursue the program as a pilot for 1,552 customers at a cost of $403,000 until Consumers can prove its functionality. Additionally, the Staff recommended that Consumers continue to pilot smart thermostats to explore whether a thermostat-based option represents a more cost-effective approach to residential load management.

Consumers requested that the Commission reject the proposed adjustment, questioning the Staff's rationale. Specifically, the company pointed to increased participation in the program, projecting 18,476 DLA switches to be installed in the test period and noting that all DLA programs are now operating. 7 Tr 1455. Thus, Consumers asked the Commission to approve the $4,892,000 in capital expense it has identified for 18,476 DLA switches. *Id.*

The ALJ recommended adopting the Staff's proposed adjustment, finding compelling the Staff's argument that only six of the 8,300 switches projected in the last rate case were installed, which the ALJ found to "diminish" the company's installation projection in this rate case. The ALJ also found the Staff's testimony, that the functionality of the switches remains in doubt, was unrefuted.

Consumers takes exception, arguing that it explained that the delay in implementing the DLA program had to do with ensuring appropriate testing and integration of associated systems. The company further argues that its projected DLA participation level accounts for growth, reflecting plans for 18,476 DLA switches, rather than the Staff's recommended 1,522 DLA customers.

In response to the ALJ's concerns about the functionality of the DLA switches, Consumers reiterates that the DLA systems are functional and that the company is ramping up the program with customer enrollments. With regard to the Staff's preference for smart thermostats, Consumers argues that choice of equipment is the company's managerial prerogative; the Staff's claim that DLA customers will abandon the program in favor of smart thermostats is highly speculative, and no party presented evidence demonstrating that the company's DLA program is unreasonable. Finally, the company notes that it presented credible expert testimony in support of its projections of customer participation in the DLA program, and requests that the Commission approve its proposed cost recovery for the DLA switches.

The Staff replies that Consumers failed to provide "evidence that the DLA switch . . . is past the testing/pilot phase and represents a functional technology within the Company." Staff's replies to exceptions, p. 12. In addition, the Staff explains that DLA switches provide no benefit to customers outside of peak load reduction, whereas smart thermostats can provide a greater peak load reduction, increased customer engagement in energy consumption, and significant overall energy savings for participants.

The Staff recommends that Consumers pilot both technologies, on a limited scale, which represents a measured approach to technology implementation that will ensure customers are only paying for the most cost-effective DLA technology. In addition, should the Commission increase projected expenditures for the DLA program above the ALJ's recommended amount, the Staff requests that the Commission require piloting of all potential DLA options to ensure customers are only paying for the most cost-effective technology in the future.

The Commission approves projected capital expenditures of $4,892,000 for the DLA program. This approved amount is predicated on 20.69 megawatts (MW) of demand savings for customer installations through the test year ending August 31, 2017. This additional funding, combined with the 22 MW of demand savings from the amounts approved for Consumers' DLA program in its last rate case, represents a fully funded commitment by the company of 42 MW of DR savings. The Commission finds this goal reasonable and achievable and stresses that it is more concerned about the program's cost effectiveness, and the demand savings actually being achieved and verified for capacity planning purposes, than about the particular technology used – whether DLA switches or smart thermostats – to reach these results. Similar to the approach for utility energy waste reduction programs, the Commission believes that the cost-effectiveness of new and existing DR efforts should be more transparent and guide decision making along with other variables such as the speed of deployment, short- and long-term impacts, customer receptivity, and balancing program offerings for different types of customers.

The testimony in this case highlighted Consumers' challenges with technology testing and system deployment that delayed the initial schedule to implement the DLA installations. Although delays may occur during the design, testing, marketing, and customer enrollment phases, the Commission observes that traditional rate setting processes are not particularly conducive to dealing with changes in program design, spending, and timing. That is, the cost recovery approach through base rates is not sufficiently flexible to account for uncertainties that impact program spending and results. On the one hand, the Commission does not want to delay authorizing cost recovery until the programs are fully deployed; yet, the Commission is also cautious about approving investments in rate base when it is uncertain the demand reductions will materialize in the test year and beyond.

Accordingly, the Commission, on its own motion in a separate docket, intends to initiate a proceeding to evaluate potential alternatives to the regulatory review and cost recovery approaches for DR. Among other considerations, the proceeding could examine the impact of new energy laws and whether the energy waste reduction program framework or DR practices in other jurisdictions could serve as a model. Therefore, the Commission will issue a separate order, in the second quarter of 2017, to provide additional guidance for this effort.

The Staff further recommended that Consumers submit an annual smart grid report demonstrating how the benefits of AMI are being executed with the deployment of AMI meters. *See*, Exhibit S-10.3. Consumers expressed a willingness to meet with the Staff to align metrics that are appropriate, and which reduce duplication of reporting requirements, based on the company's assessment that some of the Staff's metrics are not clearly defined, available, or do not correlate to the AMI benefit/cost analysis. The PFD did not provide a recommendation on whether the Commission should adopt the Staff's recommended reporting requirement.

Consumers requests that the Commission relieve the company of the requirement that it file a business case associated with the AMI program in future rate cases. The company argues that the Commission approved cost recovery for the AMI program in a series of Consumers' electric rate cases and that the company presented a business case to support its investment in the AMI program in Case Nos. U-17087, U-17735, and in this proceeding. The company points out that the vast majority of the AMI program will be implemented by the end of the test year in this case. Given the full implementation of the program, Consumers requests that the Commission dispense with the requirement of filing an AMI business case in future rate cases.

The Commission rejects Consumers' request to dispense with reporting in accordance with metrics identified in Exhibit S-10.3. And, the Commission finds that continuing to provide a business case for AMI will aid the Commission in overseeing this program's implementation going forward. The Commission concludes the smart grid reporting and the metrics the Staff has identified continue to provide the Commission with useful information on AMI. The Commission finds that the smart grid reporting and metrics shall be included in the five-year distribution investment and O&M plan discussed *supra*.

5. Plug-in Electric Vehicle Charging Infrastructure Capital Investments

For 2016 through the end of the test year, the company proposed PEV program capital costs of $10.625 million to install 30 fast chargers and 750 charging stations. Additionally, the company proposed to offer a $1,000 incentive to its electric customers who purchase a PEV and install an at-home charging station, capped at 2,500 rebates. Consumers explained that those customers who receive the proposed rebate will be required to enroll in the company’s residential PEV time of use (TOU) rate.

The Staff recommended excluding from rate base all capital costs for the proposed public charging stations and recommended treating costs associated with in-home charger rebates as a regulatory asset. In addition, the Staff recommended a utility partnership with private investors, as well as a collaborative workgroup using the former Michigan Electric Vehicle (MEV) workgroup of stakeholders that would include, among others, automotive manufacturers, charging station network operators, the Michigan Department of Transportation, and various local governing bodies to establish a coordinated statewide master plan for Michigan’s electric vehicle charging network. 8 Tr 2618-2619.

ChargePoint, a manufacturer of both public and home PEV charging stations, opposed recovery of capital expenditures associated with public charging stations because utility-owned charging infrastructure would stymie competition in the market and increase investment risk. However, ChargePoint supported the creation of an MEV collaborative, requesting that the Commission consider tasking the collaborative with basic requirements for any utility-based program in the state.

MEC/NRDC/SC also favored a collaborative stakeholder process to address the development of PEV infrastructure in Michigan, and they supported enabling Consumers to communicate with its customers about the benefits of electric vehicles and the availability of charging infrastructure.

The ALJ noted that Consumers’ proposed PEV program raises significant policy questions, including appropriate charging station network dynamics and peak demand issues, which should be addressed before Consumers enters the public charging market. He further determined that several parties raised important issues, such as the extent of the program, the requirement for "networked" chargers that can communicate, how to address multi-unit dwellings, and pricing, that also need to be addressed. Accordingly, the ALJ recommended a disallowance of $10.6 million for PEV infrastructure. However, the ALJ recommended that the Commission establish a collaborative that includes all stakeholders in the electric vehicle market for the purpose of assisting in the development of a master plan for Michigan's electric vehicle charging network.

The ALJ further concluded that concerns about the home charging rebate program are significant enough to warrant further study. Thus, he recommended that the Commission deny expenditures for that program until more details are resolved. In the alternative, the ALJ recommended that if the Commission decides to approve the home charging rebate program, the Commission should require the modifications proposed by the Staff. PFD, pp. 41-42.

In exceptions, Consumers states that it is withdrawing its PEV proposal as presented in this case, and asserts that if a MEV "Collaborative is commenced, the Company is willing to be a participant." Consumers' exceptions, p. 15. Consumers opposes the ALJ's alternative suggestion to adopt the Staff's proposal to modify and defer cost recovery of residential customer rebates for PEV charging units. The company asserts that the proposal would require Consumers to invest in rebates and the necessary infrastructure to promote and adopt increased PEV charging without cost recovery in this case. Consumers considers this result unreasonable and urges the Commission to reject it. Similarly, Consumers argues that it should not be required to undertake PEV education and outreach without related cost recovery.

The Staff states in exceptions that it supports the ALJ's recommendation for a MEV collaborative, but opposes the ALJ's recommendation to defer Consumers' electric vehicle charging proposals until after the collaborative has completed its work.

ChargePoint similarly takes exception to the ALJ's recommendation that all aspects of a PEV program should be disallowed until a collaborative is convened. ChargePoint points out that there is general support for the residential rebate among various parties and that such a program would foster innovation, competition, and customer choice in the PEV charging market. Thus, it recommends that the Commission approve the home charging rebate program, with the Staff's proposed modifications.

ChargePoint requests that the Commission withhold approval of a multi-unit rebate program until the collaborative fully addresses all relevant infrastructure and tariff issues. Finally, ChargePoint requests that the Commission establish a regulatory exemption for electric vehicle charging stations by adopting the Staff's proposed tariff modification.

MEC/NRDC/SC take exception to the ALJ's recommendation that the Commission disallow expenditures for Consumers' home charging rebate program and its Level 2-AC charging program. MEC/NRDC/SC argue that the majority of the issues concerning the home charging rebate program were resolved through rebuttal testimony and briefing. Thus, they argue that the program may be approved with minor modifications.

In place of the company's proposed Level 2 charging program, MEC/NRDC/SC support the Staff's alternate proposal wherein customers would receive rebates or reimbursement in multi-unit and workplace market segments to purchase and own Level-2 charging equipment. Under this proposal, the program would be funded by ratepayers, with recovery of program costs in the next general rate case through a regulatory asset/liability accounting authority to be created in this case. MEC/NRDC/SC note that the ALJ failed to address this proposal in the PFD. To provide a full picture of views expressed in this proceeding, MEC/NRDC/SC request that a final decision should reflect the existence and extent of agreement on the Staff's proposal as illustrated by the table provided in their exceptions. *See*, MEC/NRDC/SC's exceptions, pp. 30-31.

MEC/NRDC/SC also take exception to the PFD's lack of details regarding a timeline, goals and duties, issues to be addressed, and the organization of, and participation in, the MEV collaborative. They urge the Commission to adopt the comprehensive recommendations that were made by the Staff and MEC/NRDC/SC. Specifically, MEC/NRDC/SC note that the Staff identified specific policy goals and issues in its initial and reply briefs, as well as, a 12-month timeline for the development of an MEV collaborative roadmap. MEC/NRDC/SC additionally request that the MEV collaborative be used for continuous monitoring and review of PEV infrastructure efforts undertaken by Michigan utilities. Towards that end, they urge the Commission to require Consumers to periodically report information on its PEV program. MEC/NRDC/SC also support the Staff's recommendation for broad stakeholder participation in the MEV, which would include public interest organizations that have significant expertise in electric vehicle issues but that are not formal market participants.

In addition, MEC/NRDC/SC note that the PFD failed to address the Staff's recommendation for revisions to the company's C4.4 tariff to allow per kilowatt-hour (kWh) pricing at publicly available electric vehicle charging stations. MEC/NRDC/SC support this recommendation and ask the Commission to approve the requested tariff modification.

Consumers replies that it opposes the Staff's request that a modified program be piloted. Such a program would require investment in rebates and necessary infrastructure, with no cost recovery provided in current rates. Consumers asserts that it never included the pilot in its PEV program proposal, never included the costs associated the Staff's pilot in its filing, and that such a pilot is not part of its current business plan. Thus, Consumers urges the Commission to reject the Staff's suggestion that it subsidize third-party efforts in the PEV charging industry without the company's agreement. Consumers does not oppose the request to revise Consumers' tariff, schedule C4.4.

The Staff requests in its replies to exceptions that the Commission open a new docket creating the MEV collaborative and that the Commission approve revised language for Consumers' tariff, schedule C4.4.

In reply, MEC/NRDC/SC reiterate their support for a collaborative and request that the Commission adopt the comprehensive recommendations offered by the Staff and MEC/NRDC/SC. They also request Commission approval of the Staff's revision to the company's C4.4 tariff. ChargePoint agrees.

In reply, the Attorney General urges the Commission to require Consumers to perform a benefit/cost analysis before proceeding with a PEV proposal. He asserts that any investment in PEV infrastructure should not only be economically justified but also should not force customers who do not use PEVs to unfairly subsidize other customers' or noncustomers' use of PEVs.

Although Consumers withdrew its proposed PEV charging proposal in exceptions, the Commission is aware of the significant potential impact of a charging program on the expanded usage of electric vehicles in Consumers' electric service territory. The Commission is mindful that about a decade ago, it sponsored an electric vehicle collaborative that addressed issues when the technology was emerging and electric vehicle usage was not as common as it is today. However, automobile manufacturers in Michigan have recently announced that they will be greatly expanding the development of electric and other alternative fuel vehicles to provide future transportation options.

The Commission agrees that significant PEV charging issues were raised in this case and that emerging PEV charging technology will need further study and review to inform any future collaborative. Therefore, as an initial step, the Commission will host a technical conference inviting various stakeholders, including utilities, auto manufacturers, third-party suppliers of charging equipment, transportation planners and other parties that are not formal market participants, yet have significant expertise in PEV technology, to discuss issues associated with the deployment of PEV charging. The discussions will address both public charging stations and at-home and business deployment of PEV infrastructure. The Commission will address PEV issues on a statewide basis and not limit discussion to Consumers' service territory. Issues for discussion will include, but are not limited to, charger technology and deployment, electric rate structure for these devices, installing and maintaining charging systems, time of day usage, and electric load balancing concerning the impact of PEV charging on grid resources. Therefore, on its own motion, the Commission will issue an order in a separate docket for the purpose of initiating the PEV technical conference.

6. Demand Response Capital Expenditures

Consumers requests Commission approval of capital expenditures in the amount of $996,000 associated with its DR program. Starting with a pilot program in 2015 to manage its peak capacity needs and reduce the added expense of increased generation/capacity contracts needed during peak periods, the company states the program has 28 commercial or industrial customers of various sizes participating, including contracts for 7.7 MW of capacity. Under the program, in exchange for an incentive credit, the customer agrees to comply with requests to curtail usage up to 15 occasions during the summer months. Consumers expects the program to expand to include 560 customers reaching 150 MW of capacity in 5 years, with another 20 MW of capacity to be added by including smaller customers.

ABATE supported the enhancement of the program, which it argued should include a pilot program allowing for direct participation in the MISO DR market and rates that fully reflect avoided cost.

The Attorney General objected to the proposed DR program expenditures, arguing that the program is duplicative of Consumers' peak load management program available through its interruptible service rate. Given the availability of this interruptible rate, he questioned the necessity of another program of a similar nature with higher incentive payments and higher administrative costs. In reply, Consumers argued that the Attorney General presented no analysis or discussion of the issues pertaining to the DR program, thereby abandoning his position on this issue.

Energy Michigan recommended that the costs of the program, which it contends is a power supply capacity resource, be removed from the distribution costs allocated to retail open access (ROA) customers who are not subject to PSCR costs. 8 Tr 2729. Energy Michigan also urged the Commission to give little weight to a "capacity shortage" or "capacity gap" as justification for Consumers' DR program. According to Energy Michigan, there is no such thing as preferential treatment for Michigan in the use of a capacity resource in the MISO system that can be dispatched by MISO. Energy Michigan suggested that the concept of "exporting" or "importing" capacity among zones within MISO is meaningless in light of the current MISO resource adequacy construct where MISO uses all resources to serve all loads. Energy Michigan's initial brief, p. 6.

Hemlock supported Consumers' proposed DR program, but recommended several changes to facilitate customer participation. Specifically, Hemlock recommended the changes reflected in Exhibit HSC-11, as modified. Hemlock asserted that Consumers should pay customers a capacity credit equal to the full auction rate for capacity in MISO Zone 7 in effect at the time the DR is provided instead of the capacity credit of $25/kilowatt (kW)-year as Consumers proposed. Next, when Consumers' DR customers actually do curtail load during a mandatory event, customers should receive the full locational marginal price (LMP) for the customers' actual curtailment and not, as Consumers proposed, an energy credit of $50 per megawatt-hour (MWh) of actual load curtailed. Hemlock also opposed Consumers' proposed penalty for customers who deliver less than the contract capacity amount. Instead, Hemlock recommended that Consumers pay customers for the actual amount of "delivered capacity" provided to Consumers during a mandatory curtailment event up to 150% of accepted capacity. 8 Tr 2105.

Hemlock further recommended that for mandatory events, at a minimum, "Consumers increase its minimum advance notice period to 12 hours, which will allow for greater participation in the program, but allow for Consumers to enroll its whole portfolio of demand response load as an LMR [load modifying resource] at the same minimum notification time." 8 Tr 2107. For discretionary voluntary events, Hemlock recommended that Consumers provide day-ahead advanced notification of a possible event, based on the company's review of the day-ahead LMP values and its expected system load. Then, Hemlock contended, Consumers should provide two-hour minimum notice of the actual voluntary event, based on the company's predictions of the real-time LMP values. Hemlock also recommended that the Commission direct Consumers to use MISO's methods for establishing a customer's baseline energy and that the available methods be included in the sample contract provided to prospective customers. Hemlock asserted that the customer should not be penalized for third-party metering equipment failures or the failure of Consumers, or another party, to provide adequate notice per the contract arrangements of a voluntary or mandatory event.

The ALJ disagreed with the Attorney General's claim that the DR program is essentially the same as the interruptible rate, and thus the total expenditures for the DR program are duplicative and should be denied. The ALJ rejected the Attorney General's contention that the program will not serve its purpose because it is voluntary. The ALJ opined that the Attorney General failed to provide any basis to support his argument that the allocation of expenditures for the program are unreasonable or imprudent. PFD, pp. 47-48.

The ALJ rejected Hemlock's recommendation that Consumers use the MISO Zone 7 planning resource auction price as the capacity credit, reasoning that this proposal disregards the company's legitimate considerations in setting that credit. The ALJ disagreed with Hemlock's proposal to tie capacity payments to LMP during curtailment because it could potentially drive up rates and Consumers' costs. The ALJ found that Hemlock's proposed modification to setting the energy baseline should be rejected because it fails to consider the fact that Consumers already uses the method for setting DR baselines in Attachment TT to the MISO tariff. In addition, the ALJ rejected Hemlock's recommendation to remove the non-performance penalty from the DR program because it "would inhibit [the company's] ability to ensure the capacity resource is available when needed, which is the cornerstone of the program." PFD, p. 49. Regarding Hemlock's proposed notification timeframes, the ALJ found them to be impractical and recommended that they be rejected.

The ALJ also rejected Energy Michigan's argument that ROA customers not be allocated any costs for the program, reasoning that the requested recovery of costs necessary to implement and maintain the program will result in savings to all of Consumers' customers through lower capacity and energy costs. In conclusion, the ALJ recommended that the Commission approve the $996,000 in capitalized costs arising from its DR program.

In exceptions, the Attorney General argues that Consumers failed to provide sufficient evidence to prove that the new DR program is necessary. Because customers are not required to participate, the Attorney General reiterates that Consumers has not shown there will be sufficient customer interest to justify the $2.8 million investment in the program. He further asserts that the interruptible rate program could be modified to accomplish the same result at a much lower cost. Accordingly, the Attorney General urges the Commission to reject the proposed costs related to the new DR program.

Although ABATE supports the recommendation to approve costs for Consumers' DR program, ABATE takes exception to the extent that the ALJ did not explicitly address the issues ABATE raised in its initial brief. ABATE points out that it supported enhancement of the DR program to include a pilot large enough for customers to participate directly in DR and at rates that fully reflect avoided costs. Thus, ABATE requests that the Commission ensure that the program includes this pilot to bolster its effectiveness.

Hemlock excepts to the ALJ's recommendation to reject its proposed adjustments to the program. Hemlock notes the potential benefits of DR programs, and urges the Commission to avoid the imposition of barriers to participation. Arguing that Michigan utilities have a monopoly on DR programs for their full service customers, Hemlock states that it is imperative that those programs are effectively regulated in the public interest. Hemlock reiterates its proposed adjustments to the program outlined above, and observes that despite Consumers' agreement with Hemlock's recommendation regarding notice for voluntary events, the ALJ recommended that it not be adopted. The ALJ did not explain why this notification period was impractical when Consumers agreed it could provide the recommended notice. Hemlock requests that the Commission adopt its recommended adjustments to the DR program.

In reply, the Staff reiterates the arguments set forth in its initial brief and requests that the Commission reject Hemlock's proposed changes. The Staff states, "If all of Hemlock's proposed changes to the C&I DR Program were adopted, all the benefits would accrue to participants, while all costs and risks associated with the program would be borne by the Company and, ultimately, other ratepayers." Staff's replies to exceptions, p. 53.

In reply to the Attorney General, Hemlock asserts that "interruptible rates typically limit curtailments to actual, physical constraints. Thus, demand response programs provide another important tool in managing capacity and energy costs that are not merely duplicative of interruptible rates." Hemlock's replies to exceptions, p. 4.

In its replies to exceptions, Consumers argues that the ALJ appropriately recognized the benefits of the DR program and that it should be approved. Consumers reiterates its arguments that Hemlock's recommendations should be rejected.

Regarding Hemlock's recommended increase in advanced notice for mandatory events, Consumers restates that "it is unrealistic to expect the Company to be able to provide a minimum of twelve hours' advanced notice for Mandatory Events." Consumers' replies to exceptions, p. 61. However, Consumers does not object to voluntary events being called the day before the event and customers being notified at that time, and additionally being provided a reminder notice two hours before the event begins. Consumers also does not object to Hemlock's request to include the applicable notice provisions in DR contracts with participating customers. Consumers accepts Hemlock's request to include the MISO-dictated methods of determining DR customers' baseline energy levels in DR contracts. Further, Consumers does not object to holding DR customers harmless from penalties if Consumers does not comply with required notice provisions or if the DR metering equipment at the customers' premises does not function properly.

Consumers requests that the Commission reject ABATE's proposal to allow direct participation in DR. The company notes that, in Case No. U-16020, the Commission determined that retail customers should not be permitted to participate directly in MISO DR markets because this would have a negative impact on Consumers and its other customers because the costs incurred to plan for, and provide power to, DR customers would have to be shifted to other customers.

With respect to the Attorney General's contention that the benefits of the DR program can be achieved by Consumers' existing interruptible rates, the company argues that his position does not reflect the potential for DR, is short-sighted, and should be rejected. Consumers maintains that these two programs complement each other and both are integral components of managing capacity. Consumers points out that the "interruptible rate is a year-round program that is more appropriate for large commercial or industrial customers with high peak demands that have the ability to shed load frequently by shifting use or switching to a generator." Consumers' replies to exceptions, pp. 62-63. In contrast, Consumers argues, the DR program is event-based and designed to have customers curtail load less frequently and for shorter periods of time, specifically during the summer months. *Id*., p. 63. Thus, Consumers asserts, the Attorney General's suggestion to limit the company's options to meet capacity needs is too restrictive, and his criticism of the costs associated with the program is vague.

Having considered the parties' arguments, the evidence, and the PFD on this issue, the Commission determines that the ALJ's findings and conclusions are well-reasoned and adopts the PFD, with the exception of the following issues where Consumers and Hemlock have reached an agreement on certain details of the program. The Commission approves the agreed-upon notification for a voluntary event, which includes a day-ahead notification followed by a two-hour notification reminder the day of the voluntary event as more fully described in Consumers' replies to exceptions. The Commission also notes that Consumers does not object to inclusion of the notification requirements in DR contracts. Additionally, the Commission notes that Consumers expressed a willingness to include the MISO-dictated methods of determining DR customers' baseline energy levels in DR contracts. Likewise, the Commission acknowledges that Consumers and Hemlock have reached an agreement that program participants will not be penalized for DR metering equipment failures or for Consumers' failure to abide by notification requirements that cause a participant's failure to curtail energy use during a mandatory event. This agreement is reasonable and in the public interest.

Regarding ABATE's exceptions, the Commission agrees with Consumers that its program parameters represent the best way forward at this time and rejects ABATE's request that the program be expanded to allow a pilot for direct participation at rates that fully reflect avoided costs. The Commission notes its decision in Case No. U-16020 denying retail customers direct participation in the MISO DR market given the complexities. Moreover, it is imperative that DR benefits both program participants and non-participants. Consumers' proposed compensation model achieves this balance. Accordingly, the Commission rejects ABATE's requested modifications to the DR program.

7. Accumulated Provision for Depreciation

Consumers' updated jurisdictional adjusted depreciation reserve amount is $4,895,494,000. Consumers' initial brief, p. 68; Exhibit A-110. The Staff's jurisdictional projected test year accumulated provision for depreciation is $4,894,150,000 based on adjustments to capital expenditures to net plant. Exhibit S-2. The Commission approves the Staff's depreciation reserve balance as adjusted by this order.

8. Construction Work in Progress

As it has in several prior cases, Wal-Mart objected to the inclusion of construction work in progress (CWIP) in rate base. According to Wal-Mart, this practice unfairly requires ratepayers to cover the costs of resources that are not used and useful in the provision of utility service. Wal-Mart argues that this violates the matching principle that customers should only bear a cost when they receive a corresponding benefit. Moreover, Wal-Mart posited that by including CWIP in rate base, customers, rather than shareholders, are required to assume the risk for utility investments for projects that may never benefit ratepayers.

In response, Consumers pointed out that it is a long-standing practice to include CWIP in rate base. Consumers also argued that Wal-Mart's recommendation ignores that corresponding construction projects will be completed and operational within the period that rates set under this proceeding are in effect, thus permitting customers to receive the benefit of the costs of resources that are used and useful. Consumers noted that construction projects with costs greater than $50,000, and on-site construction activities of greater than six months duration, are offset by Allowance for Funds Used During Construction (AFUDC), resulting in a net effect of $0 on the customer. Consumers also cited several of the Commission's past decisions to include CWIP as part of the calculation of rate base. *See*, May 10, 1976 order in Case No. U-4771; December 23, 2008 order in Case No. U-15895; November 19 order, p. 24. Thus, Consumers urged the Commission to reject Wal-Mart's proposal.

The ALJ rejected Wal-Mart's position, citing company testimony that the costs are for projects that, for the most part, will be "completed and closed within a year and will be used and useful within the period that rates are in effect." PFD, p. 51, quoting 6 Tr 626. The ALJ also quoted Consumers' testimony refuting Wal-Mart's claim that CWIP costs are burdensome to ratepayers.

There were no exceptions filed. The Commission finds the PFD well-reasoned and adopts its findings and conclusions with respect to the continued inclusion of CWIP in rate base, with an AFUDC offset as initially described in the March 14, 1980 order in Case No. U-5281.

9. Working Capital

Consumers requested that total company working capital be set at $813.487 million for the test year using a balance sheet methodology that the Commission has approved in previous cases. Consistent with the November 19 order, Consumers removed temporary cash investments from the cash accounts balance of its working capital, which comprised 1% of revenues.

The Attorney General recommended a $34.6 million reduction in working capital to reflect a lower cash balance level and a higher level of interest payable. In support of this reduction, the Attorney General recommended an 11% increase in accrued interest, and a corresponding $4.6 million reduction in working capital.

The ALJ recommended approval of Consumers' working capital balance, relying on company testimony that a lower cash balance would expose Consumers to inadequate liquidity for operations and to volatility in the capital market. The ALJ also considered testimony that the cash balance representing 1% of revenues was necessary for operational considerations. Finally, the ALJ was persuaded by testimony that the company's cash balance reflects the seasonality of its cash flows, ability to obtain lower interest rates for bond financing and refinancing, and that its large capital expenditure program requires liquidity in the event of delays in obtaining long-term capital. PFD, pp. 53-54. The ALJ further noted that the 1% revenues cash balance is standard in the industry. Thus, the ALJ found that Consumers established that its proposed cash balance is reasonable and prudent.

The Attorney General takes exception, arguing that the ALJ's recommendation was erroneous because there is no industry standard. Rather, according to the Attorney General, Consumers arrived at its 1% proposal by taking cash on hand balances of a select group of utilities. He argues that there is no record evidence that commissions in those utilities' jurisdiction have approved the level of cash to be included in working capital. Thus, the Attorney General argues that Consumers' proposal lacks support.

Consumers replies that the Attorney General mischaracterizes the ALJ's recommendation. Consumers argues that the recommendation was, in fact, based on the company's testimony that established that the Attorney General's proposed cash balance reductions would jeopardize the company's liquidity and expose the company to potential volatility in capital markets. The ALJ also relied on company testimony that the proposed cash balance is necessary for operational reasons related to the seasonal nature of its cash flows, its ability to obtain lower interest rates for bond financing and refinancing, and to support Consumers' large capital investment program. Consumers also clarifies that the ALJ did not characterize the company's proposed cash balance as an "industry standard," but rather opined that maintaining cash balances greater than 1% of revenues appears to be commonplace in the industry and not unusual. Therefore, Consumers urges the Commission to reject the Attorney General's exception and approve the company's proposed working capital cash balance as recommended by the ALJ.

The Commission finds the ALJ's recommendation on this issue sound and well-reasoned and adopts the PFD based on Consumers' evidence on the factors that establish the need for the proposed cash balance.

10. Other Issues

The Staff takes exception for the limited purpose of pointing out certain discrepancies in the ALJ's capital expenditure and rate base adjustments in the PFD. However, because the Commission recalculates rate base in the final order, this issue is moot.

11. Conclusion

Based on the above decisions, the Commission finds that Consumers' total jurisdictional electric rate base is $10,159,167,000 for the test year. This is comprised of a net plant amount of $9,365,296,000 and an allowance for working capital of $822,707,000.

V. CAPITAL STRUCTURE AND COST RATES

The parties reached agreement on several balances and cost rates for components of Consumers' proposed capital structure. Remaining areas of dispute concern Consumers' long-term debt and equity balances and the appropriate rate of return on common equity.

A. Capital Structure

Consumers proposed a long-term debt balance of $5.385 billion, to which the Staff agreed. The company proposed a common equity balance of $6.129 billion, which constituted 53.1% of the permanent capital structure and 40.9% of the ratemaking capital structure. The Staff initially calculated a common equity balance of $5.959 billion, which represented approximately 52.4% of the permanent capital structure and 40.25% of the ratemaking capital structure. In rebuttal, Consumers stated that the Staff failed to include a $125 million equity infusion that was planned for March 2016, but occurred in May 2016. The Staff agreed and updated its common equity balance to $6.083 billion, or 52.87% of the company's permanent capital structure. Consumers agreed.

The Attorney General recommended reducing the company's proposed common equity balance by $353 million (and increasing the long-term debt balance by the same amount), which would bring the capital structure to Consumers' stated goal of a common equity ratio of 50%. He further argued that Consumers' capital structure should be adjusted since a higher equity balance increases costs to ratepayers because equity is a more expensive source of capital than debt. The Attorney General added that Consumers' proposed equity ratio is two to three percent higher than the average equity ratio of the proxy companies used in the company's ROE analysis.

The Attorney General claimed that Consumers' high equity balance is the result of its parent company, CMS Energy, borrowing debt capital and investing the proceeds as equity in Consumers. He further observed that Consumers' equity balance is now $1.6 billion more than CMS Energy's equity balance, compared to the $0.50 billion difference in the two companies' equity balances in 2005. According to the Attorney General, "The Commission should not allow the Company to perpetuate this scheme by constantly increasing the percent of equity capital in the permanent capital structure." Attorney General's initial brief, p. 71. Finally, the Attorney General pointed to DTE Electric's 50/50 capital structure as an appropriate benchmark for Consumers.

Consumers countered that the Attorney General seeks to alter the capital structure for arbitrary reasons and that, in any event, the company's proposed common equity ratio is not a significant deviation from the 50/50 objective. Consumers added that an equity ratio slightly above 50% is prudent in light of the significant capital investments the company intends to undertake in the next few years. Consumers also disputed that its proposed 52.87% equity ratio was out of line with the equity ratios in the company's proxy group, explaining that the Attorney General had used capital structures from the holding companies, rather than the regulated utilities, in the group. According to Consumers, when the correct values are assumed, the average equity ratio of the proxy group is about 53%. 5 Tr 488; Exhibit A-92.

Consumers pointed out that the various credit rating agencies make adjustments to debt balances to include items like power purchase agreements and leases in calculating debt to equity ratios. Thus, "[i]ncorporating the projected equity infusions in 2016 and 2017 in the common equity balance enables the Company to maintain reasonable ratios after such adjustments." *Id*. Finally, the company argued that beyond showing a difference in equity balances between Consumers and CMS Energy over a period of time, the Attorney General provided no support for his claim that CMS Energy is disguising debt as equity.

The ALJ recommended that the Commission adopt Consumers' and the Staff's agreed-to debt and equity balances, finding that the company adequately supported its request on the record. The ALJ found that, in light of Consumers' planned investments and its need to maintain a high credit rating, the company's proposed debt/equity ratio in its capital structure was reasonable.

In exceptions, the Attorney General maintains that the ALJ made inconsistent findings with respect to the company's capital investments, determining on the one hand that a higher equity balance was necessary in light of these investments, while at the same time deciding that Consumers' capital investment program was akin to other utilities' programs, thus rejecting Consumers' request for a higher ROE. The Attorney General reiterates that DTE Electric's capital structure is the most appropriate for purposes of comparison with Consumers.

In reply, Consumers argues that the ALJ considered several factors in concluding that Consumers' proposed capital structure was appropriate, repeating that the ALJ's recommendation was consistent with the Commission's previous determination that the company had valid reasons for a slightly higher equity balance. *See*, November 19 order, p. 31.

The appropriate capital structure of a utility is based on considerations of cost and risk, and in accordance with these considerations, the Commission has from time to time adjusted a company's capital structure to one that was more reasonable. While a company with more debt is a financially riskier enterprise, a company with more equity has a greater amount of capital invested in the most expensive type of capital. Not only is equity capital more expensive than debt capital, but the return on equity adds a tax burden to total revenue requirements, whereas debt does not. Thus, the Commission seeks an appropriate balance between the risks and costs of investor and debt funding.

Beginning in the 1980s, Consumers adopted a holding company structure and the Commission has treated Consumers as a stand-alone company for ratemaking purposes. However, treating Consumers as a stand-alone company has been predicated on the company maintaining "a capital structure roughly balanced between debt and equity." June 7, 2012 order in Case No. U-16794. In the instant case, Consumers states that a balanced capital structure continues to be its goal.

The Commission understands fluctuations will occur, however it notes that since Case No. U-16191, the amount of equity, on a relative basis, has been consistently increasing. During this period of time, interest rates on long-term debt have been historically low. Accordingly, the Commission agrees with the Attorney General that an imbalance is amplified when considering its impact on the overall rate of return in the current market.

On the other hand, the Commission understands the importance of access to capital, particularly in times of heavy infrastructure investment cycles. To that end, Consumers stated that it plans to implement a five-year period of significant infrastructure investments; yet, the company did not provide detail regarding the components or timing of these investments. This lack of detail makes a determination of the appropriate capital structure difficult.

The Commission desires to arrive at an optimized capital structure that is both supportive of planned infrastructure investments, yet is not unnecessarily burdensome on ratepayers. The Commission also anticipates that a cycle of heavier-than-usual investment will present an ideal opportunity to rebalance Consumers' capital structure to reach its 50/50 goal. In the next rate case, the Commission expects that Consumers will have arrived at, or will present a strategy to return to, a balanced structure within the five-year infrastructure plan time period. If Consumers is unable to do so, a more complete analysis should be included to explain why such a result is reasonable and prudent. For example, a pro-forma debt capacity analysis using rating agency methodology ratio benchmarks could be included to bolster the company's arguments.

On the basis of the record presented here, the Commission agrees with the ALJ's recommendation and adopts a common equity balance of $6.083 billion, or 52.87% of the company's permanent capital structure.

B. Cost Rates and Balances

1. Long-term Debt

Consumers proposed a long-term debt balance of $5.385 billion at a cost rate of 5.06%, based in part on two debt issuances planned for August 2015 and July 2017. The Staff agreed to the company's long-term debt balance and recommended a cost rate of 4.87%. Consumers agreed to the Staff's recommended cost rate but argued that the Staff's modification of the cost rate necessitates an adjustment to pension and other post-employment benefits (OPEB) costs.[2]

The ALJ recommended adoption of the agreed-to long-term debt balance and cost. Aside from the Attorney General's recommendation to adjust the debt and equity balances in the capital structure, there were no exceptions filed. The Commission therefore adopts the PFD on this issue.

[2] Consumers' proposed $14 million adjustment to pension and OPEB costs is addressed *infra.*

As set forth in the discussion on pension and benefits *infra*, the Commission agrees with the ALJ that there is no need to adjust the long-term debt cost. The Commission appreciates Consumers' efforts to refinance existing long-term debt when it has the opportunity to do so. Should interest cost reductions materialize in the form of refinancing or utilization of other debt instruments, *e.g.*, tax-exempt bonds, in the future, the Commission expects to see evidence that the savings will be passed along to ratepayers.

2. Short-term Debt

Consumers proposed a short-term debt balance of $165 million at a cost rate of 3.22%. The company's cost rate was derived by applying the projected London Interbank Offered Rate (LIBOR) to Consumers' forecast of the outstanding average short-term borrowing under its commercial paper facility. The Staff agreed to the company's short-term debt balance but recommended that the cost rate be based the commercial paper rate, which should also apply to Consumers' renewable energy liability balance. Consumers agreed, and the ALJ recommended the adoption of the company's short-term debt balance and the Staff's cost rate. There were no exceptions filed. The Commission finds the ALJ's recommendation reasonable and adopts the PFD.

The Commission notes that one upward driver appears to be the cost of revolving bank facility and letter of credit arrangements that are used as liquidity support. Similar to the overall capital structure, the Commission understands the importance of liquidity and short-term debt when undertaking infrastructure investment cycles. The Commission also notes the benefit they can provide to help keep capital costs low, as they delay or reduce the need for long-term debt or equity. However, ready availability of such facilities comes at a cost, including any banking arrangements that include commitment fees that are charged, whether they are currently being drawn upon or not. Accordingly, in the next rate case, Consumers shall demonstrate how the amount used and timing of short-term debt plays into the company's overall capital plan to ensure they are providing optimal benefit to ratepayers.

Lastly, the Commission notes that the utilization of financial industry-wide LIBOR projections, *e.g.*, from Bloomberg, could assist reaching an agreement on short-term rates among stakeholders more quickly in the future. As LIBOR is used as the baseline index in the company's banking arrangements, assumptions on its future levels makes a significant impact on short-term debt costs.

3. Common Equity

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

Consumers used a proxy approach in calculating its requested ROE, selecting a sample group of 19 companies, including DTE Energy. Using this sample group, Consumers applied the Capital Asset Pricing Model (CAPM) and Empirical CAPM (ECAPM), the Discounted Cash Flow (DCF) model, and a Comparable Earnings (CE) analysis, employing forecasted ROEs for the proxy companies to determine an appropriate ROE for the company. The company also used a Risk Premium (RP) approach. Consumers claimed that the risk-free rate generally used to perform these analyses is a projection of yields on U.S. Treasury bonds, but that, as a result of government intervention into monetary policy following the economic crisis in 2008, U.S. Treasury rates are artificially low. Therefore, Consumers used a risk-free rate based on the average income return of long-term government bonds from 1926-2013 as published by Morningstar in its CAPM, ECAPM, and RP analysis. The results of the company's quantitative analyses are set forth in Exhibit A-9.

In refining its ROE recommendation, Consumers also considered certain qualitative factors, including the company's good reputation, investors' view of Michigan's positive regulatory environment, uncertainty in the markets about slower growth and rising interest rates, and the company's need to attract capital in light of its plans to make significant investments in the next decade. After weighing both the quantitative results from the various models and the qualitative factors described above, Consumers recommended an ROE of 10.70%, slightly above the midpoint of its recommended range of 10.30% to 10.90%.

The Staff recommended an ROE of 10.00%, the highest level of its calculated range of 9.00% to 10.00%, based on a proxy group of 12 publicly traded utility companies, to which it applied the DCF and CAPM. The Staff also applied an RP approach, and it reviewed electric utility ROEs recently authorized by other regulatory commissions. The Staff's analyses and results are set forth in Exhibit S-4.

The Attorney General recommended an ROE of 9.75%. Exhibit AG-15. He also employed the DCF and CAPM methods, an RP approach, as well as considering current circumstances in the capital markets and potential changes in the risk profile of CMS Energy. The Attorney General used the same 19 proxy companies Consumers used, excluding one company whose earnings have declined substantially in recent years. Although the weighted result of the various models was an ROE of 8.88%, the Attorney General adjusted this to 9.75% to account for the unique circumstances and risks that Consumers faces, and as a step towards transitioning the company to the true cost of capital. In his review of ROEs authorized by other utility commissions, the Attorney General noted that the average ROE for 2015, and the first quarter of 2016, was 9.60%.

The Attorney General and the Staff took issue with Consumers' use of an historical risk-free rate in the company's CAPM and RP analyses, noting that the use of historical rates is inappropriate and results in elevated ROE results from these models. The Attorney General also criticized the company's CE approach, opining that the method the company used is unsound, imprecise, and the analysis can be easily skewed toward higher ROE results. The Staff criticized Consumers' use of the ECAPM because the model introduces a hypothetical alpha factor to the traditional CAPM model.

ABATE applied three DCF models, the CAPM, and RP approaches to the same 19 proxy companies that Consumers used, except for two companies that it excluded because they are undergoing merger activity. ABATE also recommended that considerable weight be given to the fact that electric utility ROEs have been decreasing for the past ten years and now average 9.60% to 9.70%. ABATE further noted that this decline in returns has had no effect on credit ratings for the affected companies. Like the Staff, ABATE took issue with Consumers' use of an adjusted beta in its ECAPM, on grounds that the adjusted beta double-counts the increase in the CAPM return estimates for betas less than 1.0, noting that the betas for utilities are all less than 1.0. ABATE's analyses resulted in ROEs ranging from 8.90% to 9.60%, with a recommended ROE of 9.30%, the midpoint of its range.

Wal-Mart argued that Consumers' recommended ROE of 10.70% is excessive and would significantly and adversely affect customers. Wal-Mart noted that the average ROEs approved by other state commissions from 2013-2016 range from 8.72% to 10.95% with a median of 9.75%. Exhibit SWC-4. Wal-Mart added that there is a downward trend in authorized ROEs, with eight ROEs set at 9.53% or less in 2015. Wal-Mart noted that the average ROE from 2013-2016 in Michigan is 40 basis points higher than the rest of the country.

In response, Consumers posited that the Staff's recommendation was based on quantitative analyses and "an indiscriminate comparison to other recently-authorized ROEs." Consumers' reply brief, p. 70. Consumers argued that its presentation was far more complete and reliable because it incorporated additional quantitative analyses and qualitative factors that the Staff failed to consider. Specifically, Consumers contended that the Staff failed to take into account the company's planned investment program, which is more significant than that of other utilities, the importance to analysts and investors of consistent and supportive ROEs, and the differing risk considerations of stock, rather than bond, investors. Consumers further argued that the Staff failed to consider current and prospective economic conditions in its ROE recommendation and failed to incorporate these considerations into the inputs to its quantitative analyses, noting that there are significant problems with the "mechanical" application of the various models. *Id.*, p. 79.

The ALJ found that, considering the ROE established in Consumers' previous rate case, the company had not provided any substantive evidence to show that the goals of ensuring the financial soundness of the company, and maintaining access to capital, were not met with an ROE of 10.30%. The ALJ pointed to testimony explaining that regulated electric and gas utilities generally have undergone a significant increase in capital expenditures in recent years, thus, Consumers' projected capital expenditures are in line with the rest of the industry and do not warrant a 40 basis point increase in ROE. The ALJ further found persuasive evidence that current economic conditions are stable and that the general outlook for the industry indicates that capital costs will continue to be low. Thus, the ALJ determined that Consumers' claim that a 10.70% ROE was necessary was not supported by the record.

The ALJ also agreed with ABATE's criticisms of the reliability of Consumers' models, specifically the use of an historical risk-free rate rather than forecasted rates. The ALJ found persuasive the Staff's and ABATE's arguments concerning the company's use of an adjusted beta in the ECAPM, which resulted in a higher ROE range.

Turning to an appropriate ROE for the test period, the ALJ found that the sizable reductions to ROE proposed by the Attorney General and ABATE would, as Consumers argued, be harmful to the company's credit ratings and would send an adverse signal to investors, analysts, and credit ratings agencies. With respect to the Staff's recommendation, the ALJ found:

> As for Staff's proposed 10.00% ROE, Mr. Megginson set the ROE range at 9.00% to 10.00% based on DCF modeling which had an average of 8.68%, CAPM modeling which had an average ROE of 7.96%, a Risk Premium analysis that had a range of 8.42% and 9.79%, and commission-approved ROEs in other states which averaged 9.88%. See Exhibit S-4, Schedule D-5, pg. 14. Finally, the proxy group's average authorized ROE is 10.12%, despite an average credit rating below the Company's rating S&P rating (A), and Moody's rating (A1). 8 TR 2465; Exhibit S-4, Schedule 5, pgs. 2-5. Mr. Megginson testified the 10.00% ROE would ensure the Company is still able to access credit markets on favorable terms, allow it to proceed with its capital investments, is consistent with the proxy group average, and at the same time not unduly burden [sic] ratepayers. Further, Mr. Megginson notes Staff's ROE factors in the "beneficial" provisions, in the sense it favors utilities and its investors, of Public Act 286: projected test years, self-implementation, a decision on a rate increase in 365 days, and the retail choice limit of 10% of the Company's total sales. 8 TR 2477, quoting Case No. U-17735,

> Proposal for Decision, pg. 88. Mr. Megginson's conclusions are well-supported and well-reasoned.

PFD, pp. 73-74.

In exceptions, ABATE argues that the ALJ's recommendation to adopt the Staff's 10.00% ROE was inappropriate "because the PFD fails to account for the infirmities and errors with Staff's proposal" and because ABATE demonstrated that the goals stated in the PFD could be attained with an ROE between 8.90% and 9.60%, while saving ratepayers millions of dollars. ABATE's exceptions, p. 3.

According to ABATE, the Staff's recommended 10.00% ROE was higher than the results from every one of the proxy group analyses that the Staff performed, which, when corrected, support a maximum ROE of 9.50%. ABATE criticizes the Staff's RP analysis as overstated due to the use of a risk premium based on the stock market as a whole, rather than on less risky utility stocks. ABATE adds that the Staff's RP analysis used data from 2011 and was therefore out of date. ABATE also contends that there were numerous other omissions and errors in the Staff's presentation that render it unreliable.

ABATE reiterates that Consumers does not require an ROE of 10.00% to maintain creditworthiness and financial stability. ABATE again notes that although average authorized electric ROEs have decreased to the mid-9.0% range, utilities have had no difficulties accessing low-cost capital for large investment programs, the utility industry bond rating was recently increased, and the industry credit rating outlook is stable. ABATE also takes issue with the ALJ's reliance on the company's claim that an ROE of 9.30% would be harmful to Consumers' credit ratings and financial metrics, contending that this claim was unsupported. Finally, ABATE points out that "authorizing an above-industry average ROE is not resulting in improved financial strength and lower debt cost . . . because stronger earnings strength gained from those ROEs have not resulted in above-average bond ratings. In fact, awarding Consumers an above-market cost of equity will have a significant negative impact on Consumers' competitive position, and will have a significant unjustified increase in cost to retail customers." ABATE's exceptions, p. 6.

In exceptions, the Attorney General argues that although the ALJ appropriately dismissed Consumers' proposed ROE as excessive, the ALJ nevertheless erred in recommending the Staff's 10.00% ROE. According to the Attorney General, the Staff's analysis demonstrated a range of reasonable ROEs between 7.96% and 9.88%, well below the Staff's final recommendation of 10.00%. The Attorney General cites his witness' testimony as the basis for his recommendation, and, like ABATE, asserts that the ALJ relied on unsubstantiated testimony that an ROE of 9.75% would harm the company.

In exceptions, Consumers states that the ALJ's recommendation was inconsistent. According to Consumers, although the Commission has made it clear that it expects utilities to make significant capital investments in the near future to ensure safe, reliable service, by reducing the company's ROE, the message the ALJ sends to investors indicates that they should expect significantly less for their investment capital. Consumers reiterates that Michigan's regulatory environment is considered constructive and that reducing the company's ROE below 10.30% would send the wrong message.

Consumers agrees with the ALJ's determination that the company has been able to meet its goals to attract capital and maintain financial health with an ROE of 10.30%:

> Nevertheless, the ALJ inexplicably recommends adopting a 10.00% ROE with no analysis comparing the relative merits of those two options. In fact, even considering the 10.00% ROE standing alone, the PFD offers very little reasoning to support the recommendation, relying principally on Staff's unsupported claim that a 10.00% ROE will not inhibit the Company from meeting the very goals that the ALJ already acknowledged the current 10.30% is effectively meeting today . . . .

Consumers' exceptions, p. 19.

Consumers further contends that the ALJ applied the incorrect legal standard by requiring the company to demonstrate that its previously authorized ROE was insufficient. In clarifying the correct legal standard, Consumers points to the following quotes from the Supreme Court:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties . . . . The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

Bluefield, 262 US at 692-93. And:

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Federal Power Comm, 320 US at 603. Consumers argues that these cases identified three criteria essential to selecting an appropriate rate of return: (1) compensation for risk which is comparable to other companies of like risk; (2) adequate return to ensure the financial soundness of the business; and (3) adequate return to maintain credit and attract capital. Thus, according to Consumers, it is irrelevant whether the ROE approved in the previous case was sufficient, rather, the appropriate ROE for the future test period must meet the constitutional standards for that period.

In addition, Consumers argues that the ALJ overlooked substantial evidence that current and future economic conditions, particularly rising interest rates, support an ROE of at least 10.30%. Specifically, Consumers cites testimony explaining that U.S. Treasuries and utility stocks compete for investor dollars and Treasury yields are expected to rise from historically low levels, thus making them a more attractive investment. Consumers further notes that, although occurring after the record closed, the Federal Reserve announced a quarter point increase in interest rates.[3] Consumers points to significant volatility in the stock market as additional justification for an authorized ROE between 10.30% and 10.70%.

Consumers states that the ALJ erred in his criticism of the company's use of an historical risk-free rate for the CAPM, ECAPM, and RP calculations. Consumers notes that in a footnote, the ALJ suggested that the use of historical data implies that the company is projecting that the risk-free rate will in fact increase to the historical rate. According to the company, this is not the effect of using the historical rate, and it fully supported the use of the historical risk-free rate in testimony and briefing. Consumers reiterates that none of the parties addressed the shortcomings of the CAPM, which tend to understate ROE and which the ECAPM is designed to address. The company admits that there may be more than one way to correct the problem with the CAPM, and posits that ABATE, perhaps unwittingly, cited a paper that used a different method for correcting for the current, atypical risk-free rate, thus admitting that the CAPM requires an adjustment to the beta. Consumers further contends that the ALJ ignored the company's unrefuted testimony concerning the use of an adjusted beta in the ECAPM, reiterating that the adjusted beta is a more accurate reflection of beta itself, thereby correcting the CAPM.

Finally, Consumers repeats its criticisms of the Staff's analysis contained in its rebuttal testimony and its briefs.

Several parties filed replies on this issue. The Attorney General points out that the ALJ's reference to the fact that Consumers is meeting its financial goals under its current ROE was not inconsistent with a recommendation of a lower ROE. The Attorney General posits that the ALJ's

[3] Consumers requests that the Commission take official notice of this fact.

point was “to highlight the Company’s audacity in requesting an even higher authorized ROE . . . .” Attorney General’s replies to exceptions, p. 6.

ABATE replies that it presented credible testimony demonstrating that Consumers’ ROE should be set no higher than 9.60%. ABATE further points out that it demonstrated Consumers’ use of historical rates and an adjusted beta in its ECAPM provided results that were unreliable and biased. ABATE reiterates that utilities with authorized ROEs less than 10.00% are able to fund significant capital programs, that industry analysts have upgraded utility bond ratings, and that the outlook for the industry is stable.

The Staff replies that Consumers’ request for an ROE of 10.70% “was probably the single most striking example of Company overreach in this case[,]” noting that the Commission rejected the company’s similarly overstated request in the last rate case. Staff’s replies to exceptions, p. 34. The Staff further contends that Consumers, and not the ALJ, is the one providing conflicting arguments. On the one hand, Consumers admits that its current ROE is adequate and therefore should not be changed, while on the other hand it demands a higher ROE for a future test period, on the basis of an historical risk-free rate. The Staff further responds that although interest rates ticked up slightly at the end of 2016, for the past five years, interest rates have been remarkably stable, allowing the company to access billions in capital at very low rates. According to the Staff, this is all the more reason for the Commission to adopt the ALJ’s recommendation.

The Commission finds that an ROE of 10.10% will best achieve the goals of providing appropriate compensation for risk, ensuring the financial soundness of the business, and maintaining a strong ability to attract capital. The Commission agrees generally with the ALJ’s analysis and his findings that Consumers’ proposed ROE of 10.70% is excessive, while the recommendations of ABATE and the Attorney General are unreasonably low. An ROE of 10.10%

is only slightly above the Staff's proposed range, and, as several of the parties observed, nationally, and in Michigan, ROEs are trending downward. Further, Michigan's economy has improved considerably since Consumers' ROE was set at 10.30% in 2012. In summary, the Commission finds that an ROE of 10.10% appropriately balances the interests of the company with the interests of its ratepayers, and will ensure investor confidence while protecting customers from unnecessarily burdensome rates.

4. Other Balances and Cost Rates

Consumers and the Staff agreed to a 4.50% cost rate for preferred stock, and the cost rates for long-term debt, preferred stock, and common equity components of job development investment tax credits (JDITC) should correspond to the cost rates established for long-term debt, preferred stock, and common equity, and the cost rates for other components should be zero.

C. Overall Rate of Return

The Commission adopts a 46.80/52.87 debt to equity capital structure, a long-term debt cost rate of 4.87%, an ROE of 10.10%, and an overall weighted cost of capital of 5.94%, as shown on the following table:

Description	Amount (000)	Ratio	Cost Rate	Weighted Cost
Long-Term Debt	$5,385,046	36.07%	4.87%	1.76%
Preferred Stock	$ 37,315	0.25%	4.50%	0.01%
Common Equity	$6,083,847	40.75%	10.10%	4.12%
Short-Term Debt	$ 164,600	1.10%	2.47%	0.03%
Deferred Fed Inc. Tax	$3,206,960	21.48%	0.00%	0.00%
JDITC Debt	$ 25,217	0.17%	4.87%	0.01%
JDITC Equity	$ 27,639	0.19%	10.10%	0.02%
Total	$14,930,623	100.00%		5.94%

VI. ADJUSTED NET OPERATING INCOME

Net operating income (NOI) is calculated by subtracting the company's operating expenses including depreciation, taxes, and AFUDC, from the company's operating revenue. Adjusted NOI includes the ratemaking adjustments to the recorded NOI test year for projections and disallowances. On pages 76-130 of his PFD, the ALJ provided a thorough analysis of the issues and arguments in adjusted NOI which will not be extensively repeated here.

A. Sales and Revenue Forecast

For the test year, Consumers projected its jurisdictional electric sales to be 37,784 gigawatt-hours. After various adjustments, Consumers projected sales revenue of $4.217 billion. *See*, Exhibit A-10, Schedule E-1; Exhibit A-8, Schedule C-3; Consumers' initial brief, Appendix C, p. 1, line 1, column (d).

The Attorney General argued that Consumers' residential and commercial sales forecasts are inaccurate and understated because they include sales reductions resulting from the company's energy optimization and smart energy programs. He asserted that Consumers failed to provide evidence that actual residential sales, on a weather-normalized basis, declined annually since the commencement of the energy optimization program. Attorney General's initial brief, p. 9. In addition, the Attorney General contended, Consumers' smart energy programs are in the early stages, and the company "has not provided any evidence that the programs are generating actual, tangible, energy savings of the magnitude forecasted for the test year." *Id.* He also asserted that Consumers failed to support a projected 1% decline in sales during the test year as a result of these programs. The Attorney General recommended removing the savings attributed to these programs and increasing the sales forecast by 238,288 MWh, thus increasing revenue and operating income by $10,719,945.

The Staff proposed increasing test year revenues by $4.501 million to account for an adjustment to the projected number of customers that are eligible for the Residential Income Assistance (RIA) and Residential Senior Citizen (RSC) programs. Using recent historical enrollment data, the Staff noted that the average number of customers participating in the RIA program has declined since 2013. The Staff recommended reducing the projected number of RIA customers from 70,031 to 55,045 to better align with historical data.

The Staff also proposed reducing the projected number of customers enrolled in the RSC program from 437,529 to 370,600 customers. The Staff pointed out that customer participation in the RSC program was highest in August 2015 when the company began auto-enrollment of eligible customers, but participation has steadily decreased since that time. The Staff asserted that the "Company's proposed determinant of approximately 437,529 has never been reached and recent figures do not support it." 8 Tr 2658.

Although Consumers accepted the Staff's proposed RSC adjustment, the company disputed the RIA adjustment. Consumers argued that a software error caused an oversight of 12,000 eligible customers and that after correcting the error, the company began enrolling these customers in the RIA program. Consumers argued that if the Staff's adjustment is adopted, the RIA program will be underfunded and the credit will be unavailable to eligible customers.

The ALJ determined that Consumers effectively rebutted the Attorney General's proposed adjustment. The ALJ cited Consumers' witness testimony, which confirmed that the savings attributed to energy efficiency programs are removed from the regression analysis prior to executing the models so that the company may forecast electric growth absent energy efficiency savings; the historical and forecasted energy efficiency savings are then reincorporated, along with other adjustments, into the modeling framework to create a final forecast. PFD, p. 77-78, citing

7 Tr 1291. Contrary to the Attorney General's claim that the 1% decline in sales was unsupported, the ALJ found that Consumers' proposed sales reduction "reflects the 1.3% reduction in residential and commercial deliveries set forth in the 2010-2014 Energy Efficiency reconciliation cases approved by the Commission." *Id.*, p. 78, citing 7 Tr 1291-1292.

The ALJ noted that the Staff's proposed RSC adjustment was undisputed, however he rejected the Staff's proposed RIA adjustment. Agreeing with Consumers, the ALJ found that after the software error is corrected, it is reasonable to assume that Consumers will add 12,000 eligible customers to the RIA program and, as a result, the company's proposed participation level of 66,000 is proper. PFD, p. 79.

The Attorney General filed an exception, reiterating that the company's 1% sales reduction is unsupported. He argues that the ALJ's "reference to the 1.3% reduction in 2010-2014 Energy Efficiency reconciliation cases is not relevant in this rate case . . . . It is not an actual observed rate of decline in sales from historical levels." Attorney General's exceptions, p. 13.

The Staff also excepts, disputing Consumers' adjusted RIA participation level of 66,000. Although Consumers is allegedly in the process of enrolling 12,000 overlooked eligible customers, the Staff asserts that the company failed to identify how many of those customers have already been enrolled or how many will be ultimately enrolled. The Staff contends that "until this information is provided, it is prudent to ensure that the 12,000 supposedly eligible customers are enrolled by the Company before making a significant increase to the approved participation level." Staff's exceptions, p. 28. Therefore, the Staff requests that the Commission adopt its proposed participation level of 55,045.

In reply, Consumers argues that the Attorney General failed to address the company's evidence refuting his adjustment and his suggestion that energy efficiency and smart energy savings be removed from the sales forecast. Consumers' replies to exceptions, p. 78. Consumers contends that the Attorney General's test year deliveries forecast recommendation relied on an inaccurate deliveries forecast amount. *Id*.

In reply to the Staff, Consumers reiterates that it provided evidence that 66,000 is the appropriate number of RIA customers, that it corrected the enrollment problem, and that all qualifying customers will be enrolled. Consumers argues that the Staff's position results in an unreasonable RIA customer count, is inconsistent with the purpose of projecting a test year, and is needlessly punitive to the company and eligible customers.

The Commission finds that the Attorney General's proposed adjustment to the jurisdictional sales and revenue forecast should be rejected and adopts the ALJ's finding that Consumers has not double-counted any energy efficiency savings. The Commission also agrees that the company demonstrated, via testimony, exhibits, and by noting the numerous Commission-approved energy efficiency reconciliation cases, that residential and business customers have reduced electric deliveries by 1.3% per year from 2010 to 2014.

The Commission finds the Staff's proposed RSC adjustment undisputed and adopts 370,600 as the projected customer number. Regarding the RIA customer count, the Commission agrees with the ALJ that it is reasonable to assume that Consumers has corrected the software error and that the 12,000 eligible customers will be enrolled. Therefore, the Commission adopts 66,000 as the projected test year RIA customer participation level. Based on the adjustments to the participation levels in both programs, the test year revenue impact is $3,135,174.

B. Fuel, Purchased, and Interchange Expense

Consumers projected the fuel, purchased, and interchange expense to be $2,168,037,000. *See*, Exhibit A-56, p. 1. The Staff accepted the company's calculation of this expense. The ALJ noted that the company's jurisdictional fuel cost is $2,146,990,000, while the Staff's jurisdictional fuel cost is $2,144,591,000. The ALJ stated that the "record does not provide any indication for why the Company and Staff arrived at different amounts for this expense. Given the Company provided a basis for the components of this expense through the testimony of Mr. Ronk, while Staff did not, the Company's amount will be utilized." PFD, p. 80, note 26. No party filed an exception. The Commission adopts the ALJ's findings and recommendation.

C. Other Operations and Maintenance Expense

1. Distribution and Energy Supply Operations and Maintenance

Consumers projected a total test year distribution and energy supply O&M expense of $238,353,000. This projected expense consists of $249,266,000 for the electric division, which includes a $14.6 million reduction for smart energy direct O&M benefits and $3.7 million for the customer payment programs. The company explained that the difference between the projected test year expense and the actual 2014 expense is attributed to the following: (1) a reduction of $16.3 million for service restoration, corrective maintenance, and HVD lines demand expense; (2) an increase of $17.4 million for line clearing expense; (3) an increase of $2 million for smart energy customer programs expense; (4) an increase of $6.2 million for ongoing O&M costs associated with distribution and customer service-related technology improvements; and (5) an increase of $1.1 million for North American Electric Reliability Corporation distribution compliance costs. Consumers' initial brief, pp. 108-109. The parties challenged certain aspects of these projected costs, which is addressed in more detail below.

a. Vegetation Management/Line Clearance

Consumers requested $57.3 million for a vegetation management program that is nearly identical to the line-clearing program proposed by the company in its last electric rate case. *See*, 6 Tr 1109-1115; *see also*, 8 Tr 1317-1321 in Case No. U-17735. Based on the recommendations of a consultant, the company asserted that the program will address the cause of approximately 25% of customer interruptions and implement a 7-year effective clearing cycle that is longer and more effective than the industry standard 4-6 year effective cycle.

The Staff recommended reducing the proposed vegetation management expense to $48.5 million, the amount set in Case No. U-17735, because Consumers has not spent the amount approved in rates for the last four years. 8 Tr 2583. The Staff expressed concern that “the requested spending plan in this case is based upon a recommendation from Environmental Consultants Inc. that is representative of a traditional cycle implementation and not the Company’s current effective cycle.” *Id.*, p. 2584; Exhibit S-9.3. The Staff asserted that the traditional cycle is representative of the industry best practice in vegetation management, and until Consumers employs this best practice and spends Commission-approved funding amounts, the Staff does not support any increased spending for this program. *Id.*

The Attorney General also recommended that this expense remain as approved in Case No. U-17735, based on the company’s failure to spend approved amounts in the past.

ABATE noted that “the Company’s budget for line clearing in 2016 is $48.2 million, which is a level it has not been able to achieve in the last five years and is nearly 16% below the Company’s $57.3 million test year request.” 8 Tr 2055. Therefore, ABATE recommended that the Commission approve $45.2 million, which is the highest level of spending on line clearance in the last five years and is nearly equal to the level included in current rates. However, if the Commission approves Consumers’ projected expense, ABATE requested that the Commission require annual reports on the company’s progress toward meeting the seven-year cycle to ensure that the company adheres to the plan recommended by its consultant, and order a tracker and refund provision to ensure that Consumers meets its annual spending requirements pursuant to the seven-year cycle requirement. 8 Tr 2058-2059.

Consumers responded that it is inappropriate to rely on historical spending. Instead, Consumers contended, the focus should be on the basis and benefits of its projected spending plan, which includes mitigating the cause of outages and reducing service restoration time. 6 Tr 1165. Consumers argued that it is willing and able to spend the projected amount, as demonstrated by the $24,119,000 spent in line clearing in the first six months of 2016. In addition, Consumers asserted "that the effective cycle used by the Company has a greater impact on improving reliability than a traditional 'fixed' cycle." *Id.*, p. 1166.

Though Consumers contested the consideration of historical spending in evaluating the reasonableness of projected spending, the ALJ noted that the November 19 order included an analysis of historical spending. The order stated that the "company has never spent more than $45 million annually on the line clearing program, and accordingly, is unlikely to spend the requested $57 million." PFD, p. 85, quoting the November 19 order, p. 58. According to the ALJ, the record evidence in this case demonstrates that Consumers continues to underspend in this program, it fails to explain the company's lack of spending, and it shows that Consumers is unlikely to approach the approved spending level in 2016 based on current spending. *Id*. The ALJ recommended that the Commission adopt ABATE's proposed $45.2 million for line clearing, because it is the highest spending level achieved in the last five years.

In exceptions, Consumers argues that the Staff's, Attorney General's, and ABATE's proposals are based on historical evidence and inaccurate assumptions, and they ignore the benefits customers would receive under the company's line clearing approach. Consumers states that it "is not proposing to continue its historical vegetation management program in this case but is instead proposing a more aggressive vegetation management program." Consumers' exceptions, p. 46. The company reiterates that it is willing and able to spend the projected amount as evidenced by its spending in the first six months of 2016, and requests that the Commission approve its projected line clearing expense.

In reply, ABATE states that:

> Consumers' requested amount represents a dramatic increase of over 50%, compared to the $37 million spent in 2015 on this expense, despite the fact that since 2011, Consumers Energy has not achieved the level of spending or line clearing it is requesting in this proceeding. Furthermore, Consumers has failed to spend tens of millions of dollars that it has been allowed to include in base rates over the last five years.

ABATE's replies to exceptions, p. 7. ABATE requests that the Commission adopt the ALJ's recommendation.

In replies to exceptions, the Staff reiterates that Consumers has yet to employ the necessary resources to perform the amount of line clearing approved by the Commission between 2012 and 2015. The Staff contends that:

> In fact, during that time period, the Company . . . underspent approximately $27.800 million in relation to the Commission-approved amounts. The Company has provided no further assurance in this case as compared to its past rate cases that it will actually spend the requested $57.300 million, if approved.

Staff's replies to exceptions, pp. 15-16. However, the Staff cautions the Commission against approving a spending level below that in current rates, because it may decrease reliability. The Staff also requests that the Commission adopt a one-way tracker on line-clearing funding, as proposed in its alternative IRM.

The Commission finds the Staff's proposed vegetation management amount of $48.5 million, the amount set in the November 19 order, to be the most reasonable. The Commission observes that the company has never spent more than $45 million annually on the line clearing program, and accordingly, is unlikely to spend the requested $57.3 million. Until Consumers shows that it shall consistently spend the Commission-approved amounts for line clearing, the Commission finds that the Staff's proposed amount of $48.5 million is sufficient to allow the company to continue its current trim cycle and to improve customer reliability. As discussed in further detail below, the Commission declines to adopt the one-way tracker proposed by the Staff at this time.

b. Pole-top Hardware

ABATE contended that customers are currently paying $16.3 million for annual pole-top replacements, and now "that Consumers is capitalizing these costs, the 2015 and 2016 pole-top replacements will be included in the plant investment used to establish the rates resulting from this case in 2017." 8 Tr 2064. ABATE argued that customers have already paid for this plant investment, and therefore recommended a $3.3 million reduction.

Consumers responded that it is not requesting any changes to the rates approved in Case No. U-17735, which already account for the capitalization of pole-top hardware.

Contrary to ABATE's claim, the ALJ found that O&M expenses for the program are reflected in current rates, and because Consumers is not requesting any changes, there is no overrecovery. No party filed an exception. The Commission adopts the ALJ's findings and recommendation.

c. Customer Payment Program

The Attorney General proposed excluding $3.7 million for the projected cost of Consumers' customer payment programs. He claimed that because the company eliminated the $6.25 fee for credit card payments to avoid shut-offs, uncollectable accounts and costs will decrease. Consumers disagreed and contended that the Attorney General failed to provide support for this theory. The company asserted that elimination of this fee is consistent with the credit and debit card practices of most other businesses, including other utilities, and is a benefit to the company's "most vulnerable customers." 6 Tr 1183.

Based on the evidence, the ALJ recommended that the Commission reject the Attorney General's proposed adjustment. No party filed an exception. The Commission adopts the ALJ's findings and recommendation.

d. Filing Requirements

The Staff requested that the company be required to supply more detail relative to O&M and capital spending in future rate case filings. Specifically, the Staff requested that the company provide "variance reports that provide transparency into the Portfolio Management Process and a thorough prudency review of its operation in the time period between the historic test year and the projected test year." 8 Tr 2586-2587. The Staff asserted that these reports would "alleviate the substantial burden placed on intervenors to obtain this information to begin a prudency review." *Id.*, p. 2588.

Consumers objected and asserted that the information requested by the Staff was provided, and any additional information should be obtained through discovery and audit requests. The company contended that the filing requirements and variance reports requested by the Staff would be overly burdensome.

The ALJ found the Staff's concerns well-taken. The ALJ noted the tight timeframe for these cases, and averred that it is difficult for the parties "to identify, request, and ultimately obtain the information necessary for the sufficient review of a rate filing." PFD, p. 88. In rejecting Consumers' argument that the Staff's filing and reporting requirements would be overly burdensome, the ALJ noted that the company must gather and disclose this same information during the discovery process, and therefore, the company could do so when it compiles its rate case filing. The ALJ recommended that the Commission grant the Staff's request that:

> future filings include support for reasonableness of projected costs, including investments planned for the test year and an explanation why investments previously approved were not made, consistent with the report cited by Mr. Laruwe. 8 TR 2586. In addition, the Company should be required to provide greater insight into all individual distribution O&M program expenses, including historic spending on O&M programs and projected test year spending and explanations of variations, similar to Exhibit S-9.6.

Id., pp. 88-89.

On page 49 of its exceptions, Consumers reiterates that the Staff's recommendation is unreasonable and overly burdensome because, in its direct case, the company will be required to predict every point of data that could be requested for review by the Staff and intervenors. In addition, the company states, the Staff's recommendation is needlessly duplicative of the audit and discovery process in general rate cases. Consumers contends that it is in compliance with current filing requirements and has been willing to accommodate the Staff's and intervenors' requests for additional information in the audit and discovery process.

The Staff replies that in this case, for example, Consumers failed to provide explanations and evidence to corroborate reductions set forth in distribution O&M programs, or to support project level spending projections in any of its distribution capital programs. As a result, "both Staff and the Attorney General had to take time from their analysis to request more information . . . to make sense of these reductions" and to obtain supporting evidence. Staff's replies to exceptions, p. 17. The Staff disagrees that the filing requirements are unreasonable and overly burdensome, and asserts that the requirements are "directly aligned with Public Act 286." *Id.*, p. 18.

The Commission is sympathetic to the concerns expressed by the Staff as acknowledged by the ALJ. General rate cases are conducted under relatively tight timeframes, making it important to have relevant material available at the outset rather than waiting for the audit and discovery process. Following the enactment of 2016 PA 341 (Act 341) on December 20, 2016, the need for comprehensive information and reports at case commencement is even more imperative, with the shortening of rate cases from 12 months to 10 months.

The Commission is in the process of developing updated filing requirements in Case No. U-18238. Rather than prescribe the specific expectations in this order, the Commission seeks to address these issues in Case No. U-18238. Because Consumers plans to file a new rate case prior to the conclusion of Case No. U-18238, the company is strongly encouraged to provide additional detail as requested by the Staff.

2. Fossil and Hydro Generation Operations and Maintenance Expense

Consumers projected a test year expense of $148,793,000, but reduced the projection to $146,993,000 in response to the October 11, 2016 order in Case No. U-17918 (October 11 order). The Staff recommended two adjustments as set forth below.

a. Jackson Plant Pipeline Demand Charge

The Staff recommended a $1.8 million reduction for the demand charge relating to the Jackson Plant. The Staff noted that the Commission approved recovery of this expense through a PSCR proceeding in the October 11 order. The company agreed with the Staff. The Commission finds this issue undisputed and adopts the Staff's recommended adjustment.

b. Environmental Operations

Consumers projected $16,308,000 for environmental operations during the test year to install AQCS at its power plants. The Staff recommended removing $3,262,000, or 20%, of the projected expense, because for years 2013 through 2015, the company consistently underspent. Consumers responded that its over projections were unavoidable and are unlikely to occur again. 7 Tr 1622.

The company noted that its AQCS projects are complete, the units are operating in accordance with federal and state emission standards, and the company reasonably expects to spend the projected amount.

The ALJ noted that the Staff failed to allege that Consumers' 2013-2015 environmental operations expenses were unreasonable at the time they were projected, and instead "is using hindsight to claim that because the expenses were over-stated in the past, they are likely overstated in this case." PFD, p. 90. Based on the company's testimony, the ALJ determined that Consumers resolved the cause of the over projections, and as a result, did not overstate its expenses in this case. In addition, the ALJ found that the Staff did not allege that the generating unit availability was deficient. The ALJ therefore recommended that the Staff's adjustment be rejected.

In exceptions, the Staff argues that, in addition to the installation and operation of AQCS equipment, reduced availability and outages at Karn 1 and 2 in 2013, and 2014, contributed to the over projection of environmental operations expense. The Staff reiterates that Consumers has historically over-projected environmental operations expense and requests that the Commission adopt the Staff's proposed reduction.

In replies to exceptions, Consumers restates the arguments set forth in its initial brief and exceptions.

The Commission agrees with the Staff and finds that Consumers over-projected test year expenses for environmental operations. In Case No. U-17087, Consumers projected that it would incur $2,989,000 for its 2013 environmental operations expense, however, the company only spent $2,378,000, or 79.6% of its projection. *See,* 8 Tr 2568. In Case No. U-17735, Consumers projected that its 2014 environmental operations expense would be $5,026,000, but only spent $3,958,000, or 78.8%. *Id.*, pp. 2568-2569. Also in Case No. U-17735, Consumers projected

$12,237,000 for its 2015 environmental operations expense, but the company only spent $6,249,000, or 51.1% of the amount. *Id.*, p. 2569. Therefore, based on the company's historical trend of over-projecting, the Staff applied a downward adjustment of 20% to Consumers' environmental operations expense in this case.

Consumers admits that its units had reduced availability and outages in 2013 and 2014, which caused a reduction in the company's environmental operations expense:

> [T]he generating units that utilized the AQCS equipment did not operate as projected in 2013. Karn Unit 1 was projected to operate at 90.53% availability but only achieved 69.78% availability, as shown in Exhibit A-97 (DBK-9). Karn Unit 1's reduced availability caused the AQCS equipment not to operate as forecasted. 7 TR 1623. This caused the reduction in the Company's Environmental Operations expense.
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> . . . .
>
> Although the generating units that utilize AQCS equipment operated as projected in 2014, the completion of the Karn 1 SDA [spray dry absorber] was delayed by one month and the Karn outages lasted longer than anticipated – the 60-day Karn 1 outage lasted 78-days, and the 89-day Karn 2 outage lasted 102-days. 7 TR 1624. This caused the AQCS equipment to not operate as projected, which in turn reduced the Company's Environmental Operations expense.

Consumers' initial brief, p. 128. In addition, Consumers admits that the Mercury Air Toxic Standards extension for Karn Units 1 and 2 impacted the company's projected environmental operations expense in 2015.

Although Consumers provided an explanation for the over projections in previous rate cases, the Commission finds that there is a pattern of over-projecting this expense. In addition, Consumers failed to provide evidence in this case that the company has improved the accuracy of its projections in this category. Therefore, the Commission finds it reasonable to adopt the Staff's proposed $3,262,000 reduction to the environmental operations expense.

3. Corporate Service Operations and Maintenance Expense

Consumers projected corporate service O&M expenses of $53,480,000. The Staff recommended removal of $3 million for economic development costs for several reasons. First, the Staff claimed that Consumers failed to include performance metrics for an economic development program that would measure the success of the program and hold the company accountable for its spending. 8 Tr 2527. Second, the Staff contended that Consumers' expense is duplicative because the State of Michigan already spends money on economic development to attract new business to the state. Third, the Staff noted that the Commission does not permit economic development expenses in rates for any other Michigan utility, and if Consumers is provided recovery for these expenses, it will put those other utilities at an unfair disadvantage. Finally, the Staff argued that economic development is "not a core utility function that is required to provide safe and reliable service at just and reasonable rates." *Id.*, pp. 2527-2528.

The Attorney General agreed with the Staff that economic development is not a core function of providing utility service. In addition, he contended, "when requested to put forth some goal or target of what additional load growth the company would hope to achieve, the Company has stated that it does not have a load growth target correlated to spending the incremental $3 million funding requested." 8 Tr 2297-2298.

Energy Michigan contended that economic development expenses will adversely affect full service and ROA customers and recommended that the Commission reject the request. If the Commission approves Consumers' expense, Energy Michigan requested that the amount should be allocated to power supply and distribution separately on the basis of relative dollar investment, and then collected accordingly from those rate classes.

ABATE disputed Energy Michigan's cost allocation, asserting that economic development expenses are "not related to energy consumption and do not vary with the amount of energy used by a customer class." 8 Tr 2135. In ABATE's opinion, the company's proposed cost allocation is more reasonable.

MEC disagreed that Consumers' economic development proposal would simply increase residential customers' average monthly expense by 9¢. On the contrary, MEC asserted, in addition to that expense, the production cost allocation method advocated by the company (for economic development reasons):

> would increase costs for the residential class by $31 million per year. Divided by approximately 1.58 million residential customers of Consumers Energy, this equates to an average of another $19.62 per year per customer. Added to the $1.08 per year for economic development expense, this totals over $20 more per year that Consumers wants residential customers to pay in order to facilitate the company's effort to attract more industrial customers to its service territory.

8 Tr 2179. As a result, MEC contended, the company's economic development proposal is unreasonable and inequitable.

The ALJ agreed with the Staff and the Attorney General, finding that economic development does not align with the core function of a regulated utility. The ALJ determined that if Consumers "wishes to pursue economic development activities beyond, or in conjunction with, state and local government, it may do so with shareholder, as opposed to ratepayer, funds." PFD, p. 95. Additionally, the ALJ found that the company failed to provide substantive evidence showing that a projected expense of $3 million for economic development benefits ratepayers. Therefore, the ALJ recommended adoption of the Staff's and the Attorney General's adjustment.

In exceptions, Consumers asserts that the ALJ's conclusion is cursory and unreasonably restrictive. Consumers argues that economic development activities are necessary to appropriately serve its existing and prospective utility customers, and therefore, should be considered a core component of utility service. In support, Consumers cites Case Nos. U-14347 and U-15245, wherein, the company claims, the Commission and the Staff acknowledged that economic development is crucial to utility service. The company also objects to the ALJ's recommendation to disallow economic development expenses on the basis that Consumers failed to provide specific performance metrics. Consumers argues that its "proposed economic development spending is like any other component of O&M spending, and was amply supported by expert testimony in this proceeding." *Id.*, p. 55. Responding to MEC's concerns, Consumers reiterates that the rate impact on customers would be very minor, amounting to less than 9¢ per month for residential customers.

The Staff replies that Consumers' economic development proposal is duplicative, not beneficial to customers, and lacks performance metrics to measure the company's success.

In his replies to exceptions, the Attorney General asserts that Consumers mischaracterized the Commission's decision in Case No. U-15245. He states that "[i]n that case the Commission was referring to providing discounted rates to existing or prospective customers. . . . The approach advocated by the Commission was something designed to provide a direct incentive and results, not the broad economic development program put forth by the Company in this case." Attorney General's replies to exceptions, p. 9. He argues that Consumers failed to provide evidence proving that its economic development program is just and reasonable, failed to provide specific performance goals for the program, and failed to demonstrate the benefits to customers.

In replies to exceptions, Energy Michigan reiterates the arguments set forth in its initial brief and states that Consumers did not present any new information in its exceptions that would merit reversal of the PFD. Energy Michigan also asserts that MCL 460.11 requires the Commission to set cost-based rates, and that Consumers failed to demonstrate that economic development is a cost incurred by its customers.

The Commission adopts the ALJ's recommendation. As argued by the Staff and the Attorney General, Consumers has not demonstrated that economic development is a core utility function that is required to provide safe and reliable service at just and reasonable rates. In addition, Consumers did not provide specific performance metrics, and without substantive record evidence, the Commission is unable to measure the company's spending, the success of the program, or the benefit to ratepayers.

The Commission also rejects Consumers' contention that Case Nos. U-14347 and U-15245 permit recovery of economic development expenses. The December 22, 2005 order in Case No. U-14347 (December 22 order) and the June 10, 2008 order in Case No. U-15245 were entered prior to the enactment of 2008 PA 286, which required the Commission to set cost-based rates. Therefore, any determinations in Case Nos. U-14347 and U-15245 that economic development expenses may be considered a cost of service are irrelevant to the immediate case. Additionally, although the Staff's witness in Case No. U-14347 provided testimony regarding the economic advantages of a proposed rate for large industrial customers (which included possible economic development benefits), he did not advocate for the recovery of specific economic development expenses.

4. Information Technology Expense

Consumers projected $43,326,000 for IT department O&M expenses. The ALJ noted that no party recommended an adjustment. The Commission adopts Consumers' projected expense.

5. Pension and Benefits

The company projected a total pension and benefits expense of $54,695,000. In the event the Commission adopts the Staff's proposed reduction to the long-term debt cost rate, Consumers requested a corresponding $14 million increase to its pension and benefits expense to reflect the higher expense resulting from lower interest rates.

The Staff asserted that Consumers' proposed increase is unreliable and requested that the Commission reject it. The Staff claimed that the company's requested increase can be attributed to a change in one of the many assumptions underlying the calculation used to ascertain liabilities for pension and benefits. In order to determine what, if any, increase is necessary, the Staff contended that a full actuarial re-measurement is necessary and required under Generally Accepted Accounting Principles (GAAP). The Staff requested that "the Commission rely on these re-measurements in this case and in the future," and that such "actuarial re-measurements should be considered authoritative." Staff's initial brief, p. 116. In addition, the Staff asserted, if Consumers would like to deviate from the expenses gleaned from the year-end re-measurement, the company should be allowed to do so only if it provides documentation from an actuary justifying a different expense. *Id*.

The ALJ agreed with the Staff and found that the company failed to provide substantive evidence that adjusting the long-term debt cost rate results in a corresponding increase in pension and benefits expense. PFD, p. 97. Therefore, he recommended that the Commission reject the $14 million increase.

In exceptions, Consumers argues that it provided significant evidence to support the $14 million increase and states that "[i]t would be unreasonable to ignore, and prohibit the Company from recovering, the increased pension plan expense that results from recognition of Staff's lower debt costs." Consumers' exceptions, p. 58.

In replies to exceptions, the Staff again requests that the Commission adopt Consumers' year-end actuarial re-measurement as the authoritative source for its pension and OPEB expense.

The Attorney General replies that Consumers failed to provide sufficient evidence to support its proposal and recommends that the Commission reject the proposed increase.

The Commission agrees with the ALJ, the Staff, and the Attorney General that there is insufficient record evidence to justify the company's proposed increase. As the Staff pointed out, actuarial re-measurements are comprehensive reviews and reports on pension and OPEB expenses, which are tied to GAAP financial statements and Securities and Exchange Commission filings, and which provide the best estimate for projected expenses. Therefore, the Commission finds that, going forward, full actuarial re-measurements are necessary for pension and OPEB expenses. If Consumers would like to deviate from the expenses obtained from the year-end re-measurement, the company may do so only if it provides documentation from an actuary justifying a different expense. Changes in assumptions (specifically, a change in discount rate or shift in asset allocation) should be explained by the actuary. This ensures that the expense has been reviewed and vetted by the actuary and is the most accurate projection available.

a. Active Health Care/Life Insurance/Long-term Disability

Consumers projected a test year expense of $28.012 million for active healthcare/life insurance/long-term disability (LTD) expense, which included a 5% increase in health care costs for 2016 and a 5% increase for 2017.

The Staff proposed a $3,348,000 reduction, aligning the expense level with 2015 actual costs. The Staff provided three reasons for the adjustment. First, the Staff asserted, active health care costs have declined approximately $1 million per year since 2011. Second, the Staff noted that Consumers informed investors that due to attrition, O&M costs were reduced by $35 million in 2014-2015, with an additional $35 million anticipated in 2016-2017. Third, the Staff argued, the company significantly over-projected 2015 active healthcare/life insurance/LTD costs in Case No. U-17735.

The Attorney General contended that Consumers failed to provide justification for its projected 5% increase in health care expense. As a result, the Attorney General proposed reducing the expense by $2.6 million, thus aligning the expense with 2014 actual expenses, and reflecting the fact that active health care costs have declined over the past five years. He also argued that Consumers implemented cost savings measures in 2016, such as higher co-pays and deductibles, to reduce these expenses.

The ALJ noted that Consumers cited a number of factors that were used to project its active health care costs, however, he was not persuaded that the increase in costs would be as significant as suggested by the company. The ALJ found that Consumers continues to implement cost savings measures in 2016, and that savings will continue to be realized by the company. In addition, the ALJ stated that "a reasonable assumption is [that] the Company's costs have gone down because of attrition, a fact the Company does not refute." *Id*. Although the ALJ found that the Staff's proposed reduction was sound, he determined that it was most reasonable to adopt the Attorney General's recommendation to use the higher 2014 actual expenses in the event that the reductions do not similarly continue. *Id*. Therefore, the ALJ recommended an active healthcare/life insurance/LTD expense of $25.4 million.

In exceptions, Consumers argues that the ALJ's recommendation is not supported by record evidence, and in response, recites the arguments set forth in its initial brief supporting the 5% increase. Consumers contends that, contrary to the ALJ's determination, the company is not arguing that its cost savings will end, but instead, that those savings "establish[] a new base from which future health care costs will increase." Consumers' exceptions, p. 60, quoting 8 Tr 1836.

Although the ALJ found that the company will continue to realize cost savings, Consumers argues that there is no evidence that the 2016 cost savings will result in the ability to maintain health care costs at 2014 levels. *Id.*, p. 61. Consumers also disputes that the company's attrition rate supports setting health care costs at 2014 levels.

In replies to exceptions, the Staff acknowledges that the ALJ's adjustment is substantially similar to the Staff's proposed adjustment and, therefore, supports the ALJ's recommendation.

The Attorney General reiterates in replies to exceptions that the company failed to prove that active health care costs will increase by 5% annually.

The Commission adopts the ALJ's findings and recommendation. Consumers' witness stated he provided justification for the company's projected 5% increase in his direct testimony. *See*, 8 Tr 1809-1814, 1837. After a review of the record, the Commission finds that Consumers' witness provided general references to the factors used to project the increase, but did not specifically set forth the manner in which he arrived at the 5% increase. Therefore, the Commission agrees with the Attorney General and the ALJ that Consumers failed to provide sufficient evidence to explain and justify the company's proposed 5% increase.

The Commission also finds that the Staff and the Attorney General presented persuasive evidence that Consumers' active health care costs decreased between 2011 and 2015 by as much as 4.9%. *See*, 8 Tr 2315, 2536; Exhibit AG-5, p. 2; Exhibit S-11.10. It is reasonable to assume, based on the evidence provided, that Consumers' active health care costs will decrease due to continuing attrition and cost savings measures, and that the company will continue to realize savings. In the event the annual reductions do not continue at current levels, the Commission agrees with the ALJ that it is most reasonable to adopt the Attorney General's proposed 2014 actual health care expense of $25.4 million.

b. Benefit Plans

The Staff and the Attorney General proposed removing $2.422 million for the defined benefit supplemental retirement plan (DBSERP) and $239,000 for the defined contribution supplemental retirement plan (DCSERP), asserting that these expenses do not provide benefits to ratepayers. 8 Tr 2535.

Consumers disagreed and claimed that by offering these plans, the company is able to attract, retain, and motivate executives, who, in turn, make decisions regarding safety, system reliability, improved productivity, and a financially healthy company. 8 Tr 1794, 1801-1802. In addition, Consumers contended, these executives make decisions that result in lower costs, which benefit ratepayers.

The ALJ found that "making prudent decisions that benefit ratepayers, such as making effective cost reductions, does not translate to the $2,422,000 cost of DB SERP and the $239,000 cost [of] DC SERP for the test year translating to a commensurate benefit to ratepayers." PFD, p. 100. The ALJ found that, as in Case No. U-17735, there was no record evidence showing that the $2.6 million for DBSERP and DCSERP was reasonable and prudent. As a result, the ALJ recommended adopting the Staff's and the Attorney General's adjustment.

Consumers excepts, arguing that "the record reveals the substantial benefit to customers that results from the decisions made and direction provided by the Company's executives." Consumers' exceptions, p. 63. The company reiterates arguments regarding the necessity of DBSERP and DCSERP, the benefits to ratepayers, and requests recovery of these "reasonable costs." *Id.*, p. 64.

On page 25 of its replies to exceptions, the Staff states that although the company has requested recovery of these expenses many times, "the Commission has not allowed any utilities to recover SERP or DC SERP expenses, as a component of the revenue requirement, in any rate case." The Staff notes that in each of these cases, the Commission found that the costs of these plans are not commensurate with ratepayer benefits. *Id.*, pp. 25-26. Additionally, the Staff notes, on page 72 of the November 19 order, the Commission stated that if these costs are to be recovered, the company must include metrics quantifying ratepayer benefits. The Staff contends that Consumers failed to provide the requested metrics. Therefore, the Staff requests that the Commission adopt the ALJ's recommendation. The Attorney General agrees.

The Commission agrees with the Staff, the Attorney General, and the ALJ and finds that there is no justification presented in this case to change its position on these costs. The Commission therefore adopts the ALJ's recommendation.

6. Employee Incentive Compensation Plan

Consumers initially projected incentive compensation O&M costs of $14.377 million, but subsequently capitalized $2.357 million, which reduced the amount of O&M to $12 million: $3.1 million for short-term employee incentive compensation plan (EICP) costs and $8.9 million for long-term incentive compensation. Consumers stated that it established specific performance criteria for safety, reliability, customer value, and financial health. From there, the company established 13 specific performance measures for 2015: three individual performance criteria, or measures, for safety; three for reliability; five for customer value; and two for financial performance. Consumers anticipated that essentially the same plan goals will be in effect for 2016. Consumers' initial brief, p. 144, citing 6 Tr 1019; Exhibit A-30. Consumers indicated that the goals for company officers are basically the same, but weighted differently. *Id.*, p. 146, citing 6 Tr 1025-1028.

Consumers argued that EICP and long-term incentive compensation should not be considered as supplemental to employee compensation, but as part of the overall reasonable level of compensation. The company's witness provided lengthy testimony regarding the customer benefits of EICP and long-term incentive compensation. *See*, 6 Tr 1031-1038. In addition, Consumers set forth a quantitative analysis of these benefits, but acknowledged that it was difficult to quantify every metric included in the program. *Id.*, pp. 963-967. The company requested that the Commission adopt the criteria for recovery of incentive compensation costs from the 2011 Indiana Utility Regulatory Commission (IURC) order involving Southern Indiana Gas and Electric Company.

The Staff requested exclusion of all incentive compensation costs for two reasons. First, the Staff stated that "the Commission [has] found that incentive compensation plans that were tied to Company earnings and cash flow were financial considerations that largely benefited shareholders and should not be paid for by ratepayers." 8 Tr 2530. The Staff argued that in this case, both the EICP and long-term incentive compensation plan are tied to financial metrics because most of the plans' payout is driven by achievements of target levels of performance in financial measures.

Second, the Staff claimed that the costs associated with the incentive compensation plans are unreasonable. The Staff noted that on page 72 of the November 19 order, the Commission stated that going forward, Consumers must provide "additional well-defined evidentiary support for demonstrating that the company's total compensation (historical and test year) are, in fact, reasonable compared to peer organizations." According to the Staff, in this case, Consumers failed to comply with the November 19 order because the company could not calculate the amount of total compensation included in the projected test year, or the amount of payroll as compared to historical payroll. 8 Tr 2532-2533. Furthermore, the Staff disputed the company's claim that only the overall level of compensation must be reasonable, not the specific structure of the compensation programs. The Staff argued that both factors are important, and the lack of information prevented the Staff from determining whether total compensation is reasonable compared to peer organizations and whether the costs result in benefits to ratepayers.

The Attorney General also recommended excluding all incentive compensation costs, relying on the same rationale as the Staff. Regarding Consumers' request that the Commission adopt the IURC criteria for recovery of incentive compensation costs, the Attorney General argued that the IURC criteria fails to balance the interests of ratepayers and shareholders, and results in unreasonable and unjust rates that inequitably benefit shareholders. He asserted that the IURC criteria is not representative of how most state regulatory commissions evaluate incentive compensation in setting customer rates.

The ALJ stated that within Consumers' specific performance criteria, there were 11 operational measures, which included 4 of the 5 cited by the Commission in the November 19 order. The ALJ noted that the company's witness testified about the direct customer benefits assigned to five of the metrics, and then applied a 63% allocation for electric customers for the savings under safety, quality, and productivity, which results in a benefit of $98.080 million. Consumers incorporated the benefits for distribution and generation reliability, and calculated $134.512 million of total annual quantified ratepayer benefit that the company claims is tied to the incentive compensation program. PFD, p. 105.

The ALJ noted that the "premise of [Consumers'] analysis is [that] the savings in the 5 areas . . . identified are attributable only to the short-term incentive compensation plan. In other words, the $3.510 million in savings from employee safety, i.e. the reduction in lost work days and medical expenses, were realized solely because of the incentive plan." PFD, p. 105. However, the

ALJ found that a number of other factors could have contributed to the decrease in costs as a result of employee safety, and that the company failed to identify any. The ALJ determined that the EICP, standing alone, did not result in $134.512 million in annual savings to ratepayers. Although there may have been some benefit to ratepayers as a result of the metrics used in the EICP, the ALJ stated that, based on the record, it was impossible to quantify an amount. *Id.*, pp. 105-106. Therefore, the ALJ recommended that the Commission disallow $3.1 million for EICP expense.

Regarding the long-term incentive compensation plan, the ALJ found that "it is premised solely on financial benchmarks: relative total shareholder return and relative earnings per share growth." PFD, p. 107, citing 6 Tr 1004. As a result, the long-term incentive compensation plan provides no benefit to ratepayers and the ALJ recommended a disallowance of $8.9 million.

The ALJ agreed with the Attorney General and found that adopting the IURC criteria would be a "dramatic shift from well-settled law in Michigan. PFD, p. 107. The ALJ recommended that the Commission deny Consumers' request.

In exceptions, Consumers reiterates the arguments set forth in its initial brief, and asserts that it presented evidence that the costs of the incentive compensation plans are commensurate with the benefits to ratepayers. Consumers argues that the "EICP is based on the achievement of metrics which are tied to <u>both</u> the operational and financial performance of the Company." Consumers' exceptions, p. 66. (Emphasis in original.) The company contends that the "total quantified annual operational benefit for electric customers provided by the Company's incentive compensation plan is approximately $134.512 million. This far exceeds the $12 million test year expense." *Id.* (Citations omitted.)

Consumers rejects the ALJ's rationale for disallowing EICP expense because, in the ALJ's opinion, there could be other factors contributing to the company's achievement of savings. The company argues that by the ALJ's reasoning, Consumers would never be able to prove there are customer benefits to the EICP because there is a mere possibility that another factor, other than the EICP, may have contributed to the achievement of the metrics and savings. Consumers' exceptions, p. 67.

Consumers disputes that it failed to provide the Staff the requested payroll information, and explains that the "Company's labor dollars are not segregated as an individual component of rate case O&M expense or capital expenditures. That is, the Company's rate case projections are based on project spending, and do not separate labor costs as a separate component." Consumers' exceptions, p. 70.

Consumers concludes that if the Commission disallows incentive compensation plan costs, it would be "effectively invading the Company's managerial prerogative to determine the appropriate structure of its employee compensation packages." Consumers' exceptions, p. 75.

In replies to exceptions, the Staff reiterates the arguments set forth in its initial brief and restates that the company failed to comply with the criteria set forth in the November 19 order. The Staff asserts that the Commission should reject the company's proposed incentive compensation plan costs because the total projected test year compensation level is unknown, unsubstantiated, and unreasonable. The Attorney General agrees.

Though recommending adoption of the PFD, Energy Michigan replies that in the event the Commission allows certain of the incentive compensation plan costs, "Consumers should be required to separate distribution service benefits from power supply service benefits" so that customers are only charged for the program costs from which they benefit. Energy Michigan's replies to exceptions, p. 4.

Over the past 10 years, the Commission has rejected Consumers' proposed EICP expenses because the company failed to demonstrate that the costs to ratepayers correspond with the benefits. Incentive compensation plans that include financial metrics mostly benefit the company's investors, not ratepayers. However, the Commission finds that it is reasonable for the company to recover amounts undisputedly linked to utility operating performance metrics meant to benefit customer service.

In this case, the Commission finds that Consumers provided convincing evidence that the non-financial measures of the EICP provide appreciable benefits to ratepayers and quantified the benefits associated with five metrics: employee safety, distribution reliability, generation reliability, first time quality improvement, and productivity improvement. Assuming that target performance in all non-financial measures is met, the projected payout for non-financial measures is $2,124,103. *See*, 8 Tr 2530-2531. Therefore, the Commission approves recovery of $2,124,103, of which $1,208,405 is O&M and $915,698 is capitalized.

Regarding the long-term incentive compensation, the Commission agrees with the ALJ and finds that the company failed to demonstrate that the benefits to ratepayers are commensurate with the costs. Consumers' long-term incentive compensation is tied closely to company earnings and cash flow measurements that overwhelmingly benefit shareholders. *See*, 6 Tr 1004-1005, 1027; 8 Tr 2529-2534. Consequently, the Commission finds, Consumers' long-term incentive compensation does not meet the criteria set forth in the December 22 order and is rejected.

The Commission seeks to ensure that overall salaries and wages are reasonable and competitive, are structured in a manner that rewards improved operational performance that benefits ratepayers, and that there is adequate baseline information and transparency to inform future decisions. As stated in the December 9 DTE Gas order, the Commission remains interested in a more thorough presentation of compensation levels and metrics. Rather than prescribe the specific expectations in this order, the Commission seeks to address these issues in Case No. U-18238. Because Consumers plans to file a new rate case prior to the conclusion of Case No. U-18238, the company is strongly encouraged to provide additional detail as requested by the Staff.

The Commission also notes that Energy Michigan requested, for the first time in replies to exceptions, that "distribution service benefits be separated from power supply service benefits" so that customers are only charged for the program costs from which they benefit. The Commission declines to address this issue, because no other party was provided an opportunity to examine or respond to this proposal.

7. Advanced Metering Infrastructure

Consumers projected AMI expense for the test year of $13,762,000. Consumers explained that $9,423,000 of the projected amount is comprised of expenses related to project management, systems and software expense, and smart grid infrastructure, with the remaining $4,340,000 allotted for O&M associated with the purchase and installation of smart meters. 7 Tr 1417-1423.

The Staff recommended a disallowance of $2,915,000 based on a comparison of historical actual expenses to projections made in prior rate cases. 8 Tr 2611. Consumers countered that the Staff's recommendation ignores evidence showing that the company already reduced its projected expense in this case to reflect historical actual expenses, making the Staff's disallowance duplicative. 7 Tr 1454.

The ALJ reviewed the projections for AMI O&M costs in Consumers' last rate case, comparing them to those made in this proceeding. He agreed with the company that the appropriate reductions were already reflected, and recommended adoption of the company's projected expense. PFD, pp. 108-109. No exceptions were filed. The Commission adopts the ALJ's findings and recommendation.

8. Plug-in Vehicle Charging Station

Consistent with the discussion above, the Commission finds that no PEV charging station expense shall be approved in this case. PFD, p. 109.

9. Demand Response Expenses

Consumers seeks $2,815,000 in expenses associated with its DR program. 6 Tr 859. As discussed above, the Commission has agreed with the ALJ's recommendation to allow Consumers to include $996,000 in capital costs for its DR program. Although several parties argued for modifications to the DR program, there were no requested adjustments to the projected DR O&M expense. The ALJ recommended approval of this expense amount. PFD, p. 109. No exceptions were filed. The Commission adopts the ALJ's findings and recommendation.

10. Uncollectible Expense

Consumers projected uncollectible expenses for the test year of $26.9 million. This amount is comprised of: (1) write-offs of customers' accounts receivable balances deemed uncollectible; and (2) changes during the period in the uncollectible reserve account. Exhibit A-40. Consumers utilized a three-year average bad debt loss ratio of net uncollectible accounts' expense to electric service revenue. The company applied that ratio to the test year electric service revenue plus surcharge revenue. 7 Tr 1547.

The Staff proposed a reduction of $1.826 million, utilizing a five-year historical average for the period of 2011 to 2015 on a cash basis uncollectible ratio, for a total of $25.094 million. The Staff argued that "uncollectible expenses can be sporadic over any given time period and a five-year average can better smooth out any unusual variances that may occur." 8 Tr 2538.

The Attorney General asserted that a $24.7 million uncollectible expense is appropriate. He argued that the five-year average is a more accurate approach because it captures the highs and lows of costs and reflects the improving economy. The Attorney General also argued that his figure includes a more reasonable approach for calculating the savings to uncollectible expense stemming from the installation of smart meters. He contended that applying the prorated savings based on the projected test year results in a $5.4 million cost savings. 8 Tr 2300.

Consumers responded that the five-year average employed by the Staff and the Attorney General dilutes the recent trend of higher uncollectible expenses. 7 Tr 1560.

The ALJ stated that it was unclear why Consumers believes that the five-year average approach somehow fails to capture the trend of higher uncollectibles. Citing pages 80-81 of the November 19 order, the ALJ noted the Commission's preference for the five-year average because it eliminates any aberration in a particular year that can skew the average. Accordingly, the ALJ recommended adopting the Attorney General's position on uncollectible expense. PFD, p. 111.

Consumers takes exception and argues that its methodology properly reflects recent trends in uncollectibles. Consumers further argues that its calculation of $4.956 million in cost savings to uncollectible expenses resulting from the deployment of smart meters is more reasonable.

In reply, the Staff acknowledges that its method for calculating uncollectible expense produces results similar to that of the Attorney General. Thus, the Staff has no objection to the ALJ's recommendation.

The Commission agrees with the ALJ and finds that the five-year average is the better approach for projecting uncollectible expense. The Commission is further persuaded that the average of the ratio of net charge offs to revenue for the 2011 to 2015 period, as offered by the Attorney General and accepted by the Staff, is the more reasonable methodology. Therefore, the

Commission adopts the ALJ's findings and recommendation, and finds that $24.7 million for uncollectible expense is appropriate.

On pages 3 and 4 of the November 14, 2013 order in Case No. U-17493, the Commission stated that "[e]nergy assistance programs, if properly designed and executed, have the potential to not only reduce costs for and provide other benefits to participating customers, but also reduce the utility's expenses for bad debt, disconnection/reconnection, and collection activities." Therefore, with proper execution of its energy assistance programs, including the CARE pilot program, the Commission expects that there will be a reduction in Consumers' uncollectible expense going forward.

D. Electric Injuries and Damages

The company projected $4.5 million for injuries and damages expense. As explained by Consumers, the projection was calculated using a five-year average of actual expenses for the three component costs, which consist of: (1) electric injuries and damages; (2) internal legal costs; and (3) workers' compensation costs. 7 Tr 1549.

No party requested an adjustment, and the ALJ recommended approval of Consumers' projection. PFD, p. 111. No exceptions were filed, and the Commission adopts the ALJ's findings and recommendation.

E. Meter Reading

In compliance with the Commission's directive in Case No. U-18002, Consumers removed amounts associated with meter estimation write-offs. *See*, June 9, 2016 order in Case No. U-18002, p. 23. Based on this directive, the company reduced its projected expense by $456,000. Exhibit A-70. As Consumers explained, the "reduction reflects costs that the company estimates it incurred in the past associated with additional resources within the Customer

Operations & Quality Department to handle customer calls, customer complaints, and billing issues and good faith credits issued to customers for issues from its past meter estimation practices." 6 Tr 1148.

Consumers further explained the use of good faith credits to address concerns with estimated billings: good faith credits are written off as a reduction to revenue and do not have any impact on uncollectible or corporate service expense. 7 Tr 1556. The estimated test year expense associated with good faith credits resulted in an increase of $101,498 to test year revenues. 7 Tr 1557.

No party objected to this expense, and the ALJ recommended approving Consumers' proposal. No exceptions were filed, and the Commission adopts the ALJ's findings and recommendation.

F. Depreciation and Amortization Expense

Consumers' projected depreciation expense results from depreciation rates approved in Case No. U-17653, along with projected capital expenditures and assumed plant retirements. The company revised its depreciation expense based on adjustments arising during the course of this proceeding. Consumers ultimately projected a total depreciation expense of $590.760 million, with jurisdictional depreciation expense of $588.155 million. PFD, pp. 112-113.

The Staff recommended an adjustment of $41.988 million to various components of the expense, resulting in a total depreciation expense of $586.138 million. 8 Tr 2522.

The ALJ did not make a recommendation on this issue, but appears to have agreed with the Staff's adjustment, as those figures have been inserted into Appendix C to the PFD, based on his other decisions. PFD, p. 113.

Consumers takes exception and merely states that the Commission should adopt its projected expense.

Consistent with the other decisions made in this order, the Commission adopts total depreciation and amortization expense of $588.994 million.

G. Taxes

Consumers projected jurisdictional expense for real and personal property tax expense of $167,744,000; general tax expense of $28,781,000; local income tax of $1,130,000; Michigan corporate income tax (MCIT) of $37,218,000; and federal income tax (FIT) of $134,031,000. 5 Tr 627-629; Exhibit A-112.

The Staff made adjustments to the tax expense to match positions taken within other areas of this case. Thus, the Staff recommends a $3.833 million upward adjustment to the MCIT expense, to $40.481 million. The Staff further recommends an upward adjustment of $20,201,700 to the FIT expense, to $151,790,000 (which also corrects an error that Consumers did not dispute). 5 Tr 628; 8 Tr 2540-2541.

The ALJ did not make a recommendation on this issue. PFD, p. 114. No party filed exceptions. The Commission adopts the tax amounts that reflect the other decisions made in this order.

H. Allowance for Funds Used During Construction

Consumers projected a test year jurisdictional AFUDC amount of $5.663 million. No party proposed an adjustment, and the ALJ recommended its adoption. PFD, p. 114. No exceptions were filed, and the Commission approves the company’s proposed amount.

I. Calculation of Adjusted Net Operating Income

In summary, the Commission finds that Consumers’ jurisdictional projected NOI for the 2016-2017 test year is $535,764,000.

VII. OTHER REVENUE AND ACCOUNTING ISSUES

A. Revenue Adjustment Mechanism

Consumers requested a symmetrical RAM that compares the nonfuel rate revenues approved by the Commission in the most recent proceeding to the nonfuel revenue generated through actual sales for the time period under evaluation. The company provided the same rationale for the RAM as argued in its most recent rate case, Case No. U-17735. *See*, Consumers' initial brief, pp. 169-171; 7 Tr 1326-1330. Consumers stated that its request for a RAM is conditioned upon the enactment of new energy legislation authorizing electric decoupling before the conclusion of this proceeding.

Only NRDC supported Consumers' proposed RAM. ABATE, the Attorney General, Hemlock, Kroger, and the Staff argued that Consumers' proposed electric RAM is illegal, harmful to ratepayers, and should be rejected.

The ALJ found that the Commission does not have the authority pursuant to current Michigan law to approve Consumers' proposed RAM, and approval of a conditional RAM in anticipation of authorizing legislation is improper and speculative. *See,* PFD, pp. 115-116. Therefore, the ALJ recommended that the Commission reject Consumers' proposed RAM.

After the close of the record in this proceeding, Act 341 and 2016 PA 342 were signed into law. These enactments do not provide for decoupling for electric utilities with over 200,000 customers. The Commission therefore finds that this issue is moot.

B. Investment Recovery Mechanism

Consumers proposed an IRM in its initial filing that provided "for the recovery of the Company's incremental 2017, 2018, and 2019 capital investments, beyond investments incorporated in rates through the end of August 2017, associated with specific Distribution, Generation, and Environmental Compliance programs." 5 Tr 680.

The Staff argued that Consumers' initially proposed IRM was nearly identical to the IRM that was rejected by the Commission in the November 19 order. Consequently, the Staff designed an alternative IRM that addresses the concerns of the Commission, the ALJ, and the parties in Case No. U-17735 by:

1. Setting the IRM program spending plans based on the projected test year amounts approved in this case.
2. Requiring [an] annual plan filing that provide[s] each programs['] individual projects, which can be tied to spending plans and serve as the basis for reconciliation.
3. Including an Operation[s] and Maintenance Offset to the revenue requirement.

Staff's initial brief, p. 167, citing 8 Tr 2589-2590. The Staff proposed that eight distribution capital and O&M programs be included in the IRM, which the Staff claimed would result in significant cost savings to ratepayers by increasing the efficiency of Consumers' distribution system. 8 Tr 2591-2592. For the IRM reconciliation, the Staff proposed a process that is substantially similar to that approved for DTE Gas in Case No. U-16999.

In rebuttal, Consumers contended that it was willing to accept the Staff's alternative IRM so long as the Commission approves certain modifications. First, Consumers agreed to removing generation and environmental program expenditures from the IRM, but averred that pursuant to the Staff's proposal, two electric distribution programs, reliability and capacity, must be included. Second, the company requested removal of any one-way trackers of O&M categories. Finally, Consumers was agreeable to the Staff's reconciliation process, however, the company requested "a structured and finite timeline . . . for the review and reconciliation process and for the implementation of the annual surcharge." 5 Tr 695. In the event the Commission rejects the company's modifications, Consumers requested that the Commission decline to adopt an IRM in this case.

The Attorney General, ABATE, Hemlock, Kroger, MEC/NRDC/SC, and Wal-Mart argued that the IRM is a single-issue ratemaking mechanism and must be rejected for the same legal and policy reasons as concluded by the Commission in the November 19 order.

The ALJ reviewed MCL 460.6a(1) and (2), and *In re Michigan Consolidated Gas Company*, unpublished opinion per curiam of the Court of Appeals, issued December 11, 2014 (Docket No. 316141), which affirmed the Commission's approval of an IRM in Case No. U-16999 for gas distribution, and found that the Commission has the authority to approve the Staff's alternative IRM.

Regarding the merits of the Staff's proposed IRM, the ALJ stated that the eight distribution capital and O&M programs cited by the Staff "are reactive or present the greatest opportunity to reduce costs by enhancing system reliability." PFD, p. 121, citing 8 Tr 2590. The ALJ agreed with the Staff that the costs of reactive programs are difficult to predict because they are driven by factors beyond the company's control. However, the ALJ noted, it is clear that when the costs of reactive programs increase, a corresponding reduction in spending is made in proactive programs, and this in turn, causes decreased system reliability and increases costs. *Id.* The ALJ stated that full funding and effective management of these programs will lead to better system reliability and savings to ratepayers, and therefore, recommended that the Commission approve the Staff's proposed IRM.

The ALJ rejected all but one of Consumers' requested modifications to the Staff's proposed IRM. The ALJ found that the distribution reliability program should be included in the Staff's IRM because it provides "the greatest opportunity to reduce costs and provide savings to ratepayers," whereas the capacity program should be rejected because it does "not appear to provide the benefit of significantly reducing costs." PFD, p. 122. The ALJ also denied Consumers' request to eliminate the Staff's O&M offset. In the ALJ's opinion, without the offset, the purpose of the IRM (ensuring that spending on covered programs will correspond with Commission-approved expenses) and the benefit of the IRM (reduced costs for ratepayers) are eliminated.

In a final note, the ALJ rejected the Staff's and other parties' argument that in the event an IRM is approved, it reduces the company's risk exposure and increases the risk for ratepayers, and therefore, a lower ROE is appropriate. The ALJ stated, "beyond the generality that the IRM reduces risk, the record is devoid of any evidence that quantifies the reduction, or allows for its quantification." PFD, p. 123.

In exceptions, Consumers argues that the Commission should reject the ALJ's recommendation because it results in an unreasonable and inappropriate IRM. The company reiterates that it is willing to accept the Staff's alternative IRM, however, only under the condition that it contains all of Consumers' proposed modifications. Consumers states that, "[i]f the Commission does not accept the totality of the Company's proposed modifications . . . <u>the Company withdraws its request for an IRM in this case</u>." Consumers' exceptions, pp. 78-79. (Emphasis in original.)

The Attorney General filed an exception reiterating that he opposes the company's proposed IRM and the Staff's alternative IRM, stating that, "Staff's recommended hybrid IRM is still fairly expansive and marks a major departure from prior decisions of the Commission." Attorney General's exceptions, p. 15. In his opinion, the Staff's alternative IRM is a single-issue ratemaking mechanism that fails to comply with the projected test year requirements of

MCL 460.6a(1) and does not provide adequate review of future expenditures for reasonableness and prudence.

Like the Attorney General, Hemlock filed an exception opposing Consumers' IRM and the Staff's alternative IRM. Hemlock states that the Staff's alternative IRM "functions more as a series of tracking mechanisms than the IRM proposed by Consumers," and "is a form of rate adjustment that would not capture other material changes in Consumers' cost of service that could offset a need for a rate increase for incremental plan investments." Hemlock's exceptions, p. 40. Hemlock argues that a rate case is a more effective and accurate venue for ensuring that rates are designed to recover the utility's cost of service, and therefore, recommends that the Commission reject Consumers' and the Staff's proposed IRMs.

ABATE also excepts, disputing that the Staff's alternative IRM resolves the Commission's concerns in the November 19 order. ABATE argues that the Staff's alternative IRM will:

> (i) shift regulatory risk from utility investors to ratepayers outside of a base rate case, accelerating investor recognition of specific costs in rates; (ii) occur without a corresponding reduction in rate of return to reflect reduced business risks; (iii) act as a dis-incentive for utility management to control cost escalations; and (iv) Michigan's adoption of Public Act 286's allowances for self-implementation and 12-month rate case final order requirement have significantly diminished the need for tracker mechanisms.

ABATE's exceptions, p. 14. In addition, ABATE states, the Staff's alternative IRM effectively doubles Consumers' requested rate increase. Finally, ABATE asserts that Consumers has consistently over-earned for the past five years with its 10.30% ROE, which makes the IRM unnecessary. Therefore, ABATE requests that the Commission reject the Staff's alternative IRM.

Consumers agrees with the Attorney General, ABATE, and Hemlock that the ALJ's recommendation should be rejected, however, in replies to exceptions, Consumers states that its rationale differs. Contrary to the other parties' contention that *any* IRM should be rejected for legal and policy reasons, Consumers argues that an IRM is authorized by MCL 460.6a(1), the statute provides for the recovery of costs beyond the 12-month test year, and that the Staff's alternative IRM, with the company's proposed modifications, is reasonable and prudent. However, if the Commission declines to adopt the Staff's alternative IRM with Consumers' requested modifications, the company reiterates that it is withdrawing its request for an IRM in this case.

In replies to exceptions, the Attorney General, ABATE, and Hemlock reiterate their objections to an IRM, as set forth in their briefs and exceptions, and request that the Commission reject the ALJ's recommendation.

Although the Commission appreciates the Staff's effort to craft an IRM that addresses the Commission's concerns in the November 19 order, the Commission finds that the ALJ's recommendation should be rejected. As discussed above, the Commission required Consumers to submit a five-year distribution investment and maintenance plan. The Commission notes that valuable information may be gleaned from the plan regarding Consumers' anticipated needs, priorities, and spending for the next five years, and it may reveal whether or not an IRM is necessary and appropriate, and how it should be structured. As a result, the Commission finds that approval of an IRM is premature at this time.

The Commission notes that Consumers requested that its proposal for an IRM be withdrawn in the event the Commission declined to approve the Staff's alternative IRM with the company's proposed modifications. As discussed above, the Commission declined to adopt the Staff's alternative IRM at this time, and as a result, the Commission finds that the company's proposed modifications are moot. Therefore, the Commission finds that Consumers' request for an IRM is withdrawn.

C. Accounting Requests

1. Deferred City Income Taxes

In prior years, Consumers incurred an inconsequential amount of city income taxes and the company determined that it was a much too sizable and time-consuming task to track an immaterial amount. However, Consumers stated, in recent years, there have been large increases in the company's deferred city tax liabilities, and the amount has become significant. Consumers requested authority to prospectively record these taxes using the GAAP deferral accounting method, to record a one-time adjustment to deferred income tax liabilities of approximately $14 million, and to recognize an associated regulatory asset of approximately $14 million. 5 Tr 743-747. Consumers also requested that the Commission "authorize the straight-line recovery of the regulatory tax asset over a 20-year period, the approximate period over which the associated book/tax differences will reverse." *Id.*, p. 747.

The RCG objected that Consumers' request constitutes retroactive ratemaking. Consumers disagreed, asserting that "[i]n *In Attorney General v Pub Serv Comm*, 262 Mich App 649; 686 NW2d 804 (2004), the Court of Appeals held that deferred accounting treatment of past expenses coupled with the amortization of the deferred amounts in future rates does not violate the rule against retroactive ratemaking." Consumers' reply brief, p. 174. Consumers averred that its proposal for the city income taxes is the same in all material respects to the deferred accounting and ratemaking method upheld by the Court of Appeals in *Attorney General*. *Id.*, p. 175.

The ALJ agreed with Consumers, stating that:

> [b]ased on this authority, deferred accounting and ratemaking treatment is proper, provided it doesn't readjust rates charged in prior years and is consistent with regulatory and accounting principles. Based on Ms. Hesche's testimony, and given that the proposal is limited to rates charged in the future, the accounting request for Deferred City Income taxes in [sic] not retroactive ratemaking under the authority cited by the Company.

PFD, p. 125. The ALJ recommended that the Commission grant Consumers' request for deferred accounting and ratemaking treatment.

The RCG excepts, reiterating the arguments set forth in its initial brief. The RCG asserts that Consumers has presented no evidence that it has not already recovered, pursuant to the ratemaking formula, all past federal, state, and local income taxes. In addition, the RCG claims that "[t]he application of a tax factor escalation factor to CECO's revisionist retroactive accounting changes is also egregious." RCG's exceptions, p. 7.

In its replies to exceptions, the company states that the RCG failed to allege any specific errors made by the ALJ, and instead, reiterated the arguments set forth in its initial brief. Accordingly, Consumers reiterates its response to the RCG from its reply brief, and requests that the Commission reject the RCG's exception.

After reviewing Consumers' proposal, the Commission agrees with the ALJ that the company's request should be approved. Consumers proposed to account for deferred city tax liability using the GAAP deferral accounting method, which the Commission agrees is the tax policy that was approved in the February 8, 1993 order in Case No. U-10083, affirmed in the February 15, 2012 order in Case No. U-16864, and the method that has been used to account for state and federal deferred income taxes for many years.

In addition, the Commission concludes that Consumers' proposed treatment of deferred city income taxes does not constitute retroactive ratemaking. Because Consumers is requesting approval to *prospectively* use deferred income tax accounting for city income taxes, and not a modification of rates set in a previous case, the Commission finds that the company's proposal correlates with the deferred accounting and ratemaking treatment upheld by the Court of Appeals in *Attorney General*, 262 Mich App 649; *see also, ABATE v Pub Serv Comm*, 208 Mich App 248, 261; 527 NW2d 533 (1994). Regarding the cases cited by the RCG in support of its position, the Commission finds the cases inapposite.

2. Coal Combustion Residual Accounting Retirement

Following the finalization of a federal rule regulating CCR, MDEQ promulgated more prescriptive state standards for certain categories of waste management facilities. As a result, Consumers projected an additional Asset Retirement Obligation (ARO) and "recorded a $68 million increase to its coal ash disposal ARO, including $47 million of coal ash disposal and $21 million of required ground water monitoring." Consumers' initial brief, p. 191.

According to the company, "asset retirement costs are recovered through cost of removal in depreciation rates, and the Company proposes that this new ARO be included in Consumers Energy's next electric depreciation case." Consumers' initial brief, p. 191. In addition, Consumers requested approval to establish a regulatory asset/liability so that the company may recognize the timing differences between the cost of removal included in depreciation rates compared to ARO accretion and depreciation expense recognized on Consumers' books and to keep ARO accounting income statements neutral. *Id.* The company contended that this is the same methodology used for Consumers' other AROs, and requested the same recovery as was approved for its existing AROs.

The ALJ stated that no party objected and therefore, he recommended that the request be granted. There were no exceptions filed. The Commission therefore adopts the PFD on this issue.

3. Classic Seven Remaining Inventory

Consumers filed an application in Case No. U-18048 requesting approval to record, as a regulatory asset, the remaining book value of the Classic Seven Remaining Inventory at the time of retirement. In the immediate case, Consumers requested to amortize the regulatory asset over a two-year period from the date of an order granting approval for recovery. The Commission issued an order in this case on May 20, 2016, concluding that it is reasonable to grant accounting treatment related to the inventory, parts, and equipment associated with the Classic Seven's retirement. The Commission found that the inventory, parts, and equipment expenses associated with the retirement of the Classic Seven should be charged to cost of removal and directed Consumers to include in its next electric depreciation case the inventory, parts, and equipment expenses associated with the Classic Seven's retirement.

4. Revenue Adjustment Mechanism

In its application, Consumers stated that the implementation of the company's proposed RAM would require necessary accounting approvals. However, because the Commission declined to approve a RAM in this case, the Commission finds that the request for these accounting approvals is moot.

5. Line Loss

MEC/NRDC/SC did not object to the recovery of Consumers' grid modernization expenses, however, they made two recommendations regarding those expenditures. MEC/NRDC/SC first requested that Consumers make "specific efforts to reduce line losses in its distribution system . . . ," and "adopt[] dynamic volt-VAR control and . . . practice Conservation Voltage Reduction," which can be "greatly facilitated by using data from" AMI meters. 8 Tr 2189-2190. Second, MEC/NRDC/SC proposed that Consumers be required to report the actual benefits and costs of grid modernization expenditures, and reflect the results in the PSCR line loss factor. *Id.*, p. 2190.

Consumers responded that MEC/NRDC/SC's recommendations are unclear, unnecessary, and premature. According to Consumers, MEC/NRDC/SC failed to provide any "details about specific report measurements, frequency, algorithms, or source data availability that may span across many operational systems to support such practices." Consumers' initial brief, p. 194, quoting 6 Tr 1189. Consumers further contended that its grid modernization program is not fully deployed, which will impact its ability to perform any of the practices recommended by MEC/NRDC/SC. In addition, Consumers argued that MEC/NRDC/SC's recommendations are not the most cost-effective methods to address line loss issues, and asserted that the expenditures that the company is making in New Business, Reliability, Grid Modernization, Capacity, and Asset Relocation programs already provide opportunities for line loss reductions. Finally, Consumers stated that the Commission has previously rejected MEC/NRDC/SC's request to review line losses in the context of PSCR cases because line losses are more appropriately considered in the context of electric general rate cases. Therefore, Consumers requested that the Commission reject MEC/NRDC/SC's recommendations.

The ALJ agreed with Consumers, but noted that in the November 19 order, the Commission highlighted "the importance of reducing energy waste and directed the Staff 'to engage with stakeholders on the process going forward to educate and enhance understanding of this complex issue.'" PFD, p. 130, quoting November 19 order, p. 93. Continuing, the ALJ stated:

> Given that AMI meters/Grid Modernization have not been fully deployed or connected to the Company's operational systems, the reporting of benefits is premature. Assumedly, the Commission's directive regarding engagement with stakeholders is proceeding and is sufficiently addressing steps that can reduce energy waste. Finally, the Company's objection to Mr. Jester's recommendation that line losses be reviewed, and if necessary, adjusted in PSCR cases, is valid. As Mr. Bordine noted, a line of Commission orders declined to order that step.

Id.

There were no exceptions filed. The Commission therefore adopts the PFD on this issue. The Commission also expects line losses and efficiency improvements resulting from AMI implementation to be covered in the company's distribution plan.

VIII. REVENUE DEFICIENCY SUMMARY

In accordance with the foregoing findings, Consumers' jurisdictional revenue deficiency for the test year is computed as follows:

Rate Base	$10,159,167,000
Required Rate of Return	5.94%
Income Required	$603,186,000
Adjusted Net Operating Income	$535,764,000
Income Deficiency (Sufficiency)	$67,422,000
Revenue Multiplier	1.6377
Demand Response Revenue Requirement	$2,861,000
PEV Revenue Requirement	$0
Total Revenue Deficiency	$113,277,000

IX. COST OF SERVICE

A. Production Cost Allocation

Consumers provided two cost of service studies (COSS). COSS Version 1 is based on a 75% demand, 0% on-peak energy, and 25% total energy production cost allocation, with four coincident peaks (4CP) for the demand component, or 4CP 75-0-25. Exhibit A-11, Schedule F-1. This allocation is the same as was approved in Consumers' most recent rate case, and the same as that applied in the 2014 historical COSS. November 19 order, p. 98; 5 Tr 544.

However, Consumers requested approval of its COSS Version 2, which applies a 4CP 100-0-0 production cost allocation. Exhibit A-11, Schedule F-1.1. Consumers contended that the residential and secondary classes have a significantly higher contribution to the company's system peak capacity requirements. 5 Tr 548. Consumers argued that because capacity planning is designed to meet demand, the 4CP 100 allocation "better aligns each customer class' assigned capacity cost recovery with the capacity costs actually incurred to serve each customer class." 5 Tr 545. Approval of the 4CP 100 allocation method would increase capacity costs by $31 million for the residential class and by $5 million for the secondary class, and would lower capacity costs by $33 million for the primary class.

The Staff supported the currently-approved allocation method, arguing that production assets are not obtained solely to meet peak capacity demand, but also to meet energy requirements for all hours in the year. 8 Tr 2683. The Staff noted that the Commission considered and rejected Consumers' proposed new allocation method in two recent Act 169 orders.

MEC/NRDC/SC opposed the 4CP 100 allocation method, and offered the equivalent peaker method instead, which would allocate the fixed costs of baseload at 4CP 50-25-25 and peaking assets at 4CP 100-0-0. The Attorney General also opposed the proposed 4CP 100 allocation method.

ABATE, Kroger, Wal-Mart, and Hemlock supported the 4CP 100 allocation method. ABATE argued that the energy component of the currently-approved allocation method is outdated, because the prevalence of natural gas means that utilities have lower capital investment and fuel costs. Kroger and Wal-Mart contended that capacity planning is designed solely to meet summer peak demand, and Hemlock argued that the 4CP 100 allocation method better reflects the competitive nature of market prices.

The ALJ began by noting that the production cost allocation method has been "litigated and considered by the Commission twice in the past 18 months," and that the Commission has consistently found that any acceptable production cost allocation method must reflect both demand and energy. PFD, p. 140. The ALJ found that year-round energy use is an appropriate consideration in determining production costs, stating that, "[s]ince both demand and energy requirements factor into production costs, under the theory of causation the costs must be allocated accordingly. The 4CP 75-0-25 method does that, while the 4CP 100-0-0 method does not." PFD, p. 141.

Consumers excepts, contending that 4CP 100 is the most appropriate production allocation method when considering "generation system planning and operation, the availability of load and operations data, and rate design objectives." Consumers' exceptions, p. 84. Consumers acknowledges that "the Company's production capacity portfolio has been assembled to economically address customer demand throughout the year," but argues that 4CP 100 "reasonably allocates the production capacity" because capacity planning is designed to meet summer demand. *Id.*, p. 85; 5 Tr 546. Consumers maintains that the currently-approved allocation method provides

inaccurate price signals, especially during off-peak periods, and that capacity expense and energy expense should be allocated separately. Consumers argues that its baseload proxy analysis shows that the residential class's average minimum demand represented 45% of the company's total baseload capacity in 2011 through 2014. Thus, Consumers states, the 4CP 100 allocation method is superior because it apportions 44.3% of production capacity costs to the residential class, while the 4CP 75-0-25 method only apportions 42.6% of production capacity costs to that class.
5 Tr 549-556.

In exceptions, ABATE argues that Consumers is not building coal-fired plants for new generation and therefore, 4CP 100 best reflects cost causation and sends appropriate price signals to customers to reduce demand. ABATE contends that fixed costs should be allocated to the customers whose demand necessitates them, and that the currently-approved allocation method is based on a generation acquisition theory that no longer applies.

Hemlock also takes exception, reiterating that the 4CP 100 allocation method is most consistent with cost causation and most accurately reflects competitive market pricing of production costs. Additionally, in light of the statutory mandate for cost-based rates, Hemlock contends that it is important that the Commission reconsider its position on this issue. Hemlock's exceptions, p. 4, citing MCL 460.11(1). Hemlock states that it provided a new analysis in this case showing a "clear relationship" between production capacity costs and energy costs, and that "[t]hese resource costs also make clear that it would not be economical to pay a higher capacity cost without a lower energy cost." 8 Tr 2077. In Hemlock's opinion, the currently-approved allocation method creates just such an uneconomic result, producing rates that are not based on the actual cost of service.

In replies to exceptions, ABATE supports Consumers' proposal and agrees with Hemlock.

MEC/NRDC/SC reply that Consumers, Hemlock, and ABATE offer no new information or evidence on this issue, which has been decided several times in recent rate and cost allocation cases. MEC/NRDC/SC also point out that in Act 341, which was signed into law on December 20, 2016, and becomes effective on April 20, 2017, the Michigan Legislature revised MCL 460.11(1) to create a presumption in favor of the 75-0-25 allocation method. The new law states that:

> The commission shall ensure that the cost of providing service to each customer class is based on the allocation of production-related costs based on using the 75-0-25 method of cost allocation and transmission costs based on using the 100% demand method of cost allocation. The commission may modify this method if it determines that this method of cost allocation does not ensure that rates are equal to the cost of service.

MCL 460.11(1), effective April 20, 2017. MEC/NRDC/SC contend that the Legislature has provided clear direction as to the appropriate allocation method. In addition, MEC/NRDC/SC assert that the proxy analysis relied upon by Consumers to support its 4CP 100 proposal was shown on cross-examination to rely on a questionable methodology. 5 Tr 576-579. MEC/NRDC/SC conclude by noting that Consumers erred in asserting that energy costs are allocated to the classes on a system average basis.

In replies to exceptions, the Staff also refers to the Commission's previous determinations regarding the functions of capacity planning, which include both identifying the total amount of capacity needed to serve peak load, as well as, selecting the type of capacity needed to serve peak load. June 30, 2015 order in Case No. U-17688, pp. 15-16. The Staff disputes Hemlock's contention that the ALJ overlooked new evidence regarding production cost allocation in light of competitive market pricing for production costs. Rather, the Staff asserts, the ALJ considered and properly rejected Hemlock's claimed "new evidence." In addition, the Staff supports the arguments made by MEC/NRDC/SC and agrees that the proxy analysis provided by Consumers does not reflect actual load and arbitrarily focuses on certain hours of the day.

Year-round energy use is an appropriate consideration in determining the allocation of production costs. The Commission has thoroughly considered and rejected the 4CP 100 option in two recent cost allocation cases, and three recent rate cases. *See*, June 15, 2015 order in Case No. U-17689, pp. 21-22; June 30, 2015 order in Case No. U-17688, pp. 15-16; November 19 order, pp. 96-98; December 11 order, pp. 112-113; and January 31 order, p. 100. No party presented new evidence or a new analysis in this record that persuades the Commission to adopt Consumers' COSS Version 2 proposal.

B. Intersystem Sales Allocator

Intersystem sales represent the revenue gained from the increased use and sale of generation above the needs of customers. In COSS Version 2, Consumers proposed changing the intersystem sales allocator from capacity to energy. The proposed change would decrease the residential class's revenue credits by $11 million and the secondary class's by $2 million, and would increase the primary class's revenue credits by $8 million. 5 Tr 549.

The Staff opposed the change, arguing that there is not enough information on the record to determine whether the change is reasonable. 8 Tr 2684. Because the proposal would shift revenue responsibility fairly significantly between classes, the Staff recommended that the proposal be rejected at this time.

The ALJ found that the proposal should be denied, agreeing with the Staff that the record evidence is insufficient to support the company's request. PFD, pp. 143-144.

In exceptions, Consumers contends that adequate evidence supports its request. Consumers notes that intersystem sales constitute the net sale of energy to the energy market operated by

MISO. Consumers states that this includes both the sale of energy where there is a surplus of generation (which costs less to produce than the market price), and the sale of energy strictly for reliability purposes, and that only 5% of Consumers' total intersystem sales result from the latter. 4 Tr 347-348; Exhibit A-56. Consumers thus argues that these are energy sales only, not capacity, and the total amount of sales should be based on the energy allocator rather than the capacity allocator.

ABATE excepts, arguing that it provided substantial testimony showing that there is a current mismatch between the allocation of sales and costs, which an energy allocator would remedy. 8 Tr 2011, 2047.

Hemlock also takes exception, contending that Consumers' proposal will appropriately increase the revenue credits applied to the primary class and reduce the revenue credits applied to the residential and secondary classes. 8 Tr 2129-2130.

In reply, ABATE supports Consumers' proposal and agrees with Hemlock.

The Staff argues in replies to exceptions that the benefit of intersystem sales revenue should accrue to customers in the same way that generation cost is paid for by customers – through the production cost allocator. The Staff contends that the ALJ correctly recommended retaining the current intersystem sales allocator.

The Commission agrees with the ALJ and the Staff. The Staff determined that there was insufficient information to judge whether the proposal is reasonable, and that, based on the information that it had, the change would increase the revenue deficiency associated with the residential class by $7.4 million and decrease the revenue deficiency associated with the primary class by $6.8 million. 8 Tr 2684. These are not insignificant amounts, and the Commission finds that the direct and rebuttal testimony provided by Consumers does not provide the thorough support for this proposal that is needed.

C. Uncollectible Account Expense Allocator

The uncollectible account expense allocator is currently based on the average number of customers, which results in 88% of uncollectible expense being allocated to residential customers. 5 Tr 559. The Staff proposed to change the allocation to one based on class revenue requirements because uncollectible expense is a general cost of doing business. 8 Tr 2685-2686. Consumers countered that such an allocation would result in the residential class paying only 45% of uncollectible expense, even though that class causes 91% of the expense, and would assign some portion of uncollectible expense to classes that have almost no uncollectible accounts.
5 Tr 559-560.

The ALJ agreed with Consumers, finding that the Staff's proposal would violate principles of cost causation and is inconsistent with Commission precedent. PFD, p. 144. The ALJ noted Consumers' evidence showing that the residential class is the origin of 91% of this expense, and that under the Staff's proposal, the residential class would be allocated only 45% of uncollectible expense, while the existing method apportions 88% of uncollectible expense to that class.

In exceptions, the Staff argues that its method best matches with cost causation because it allocates uncollectible expense in an equitable way to all customers. The Staff points out that the National Association of Regulatory Utility Commissioners' Manual does not advocate any one particular method for uncollectible expense allocation, and argues that treating it as a general cost of doing business is cost-based and reasonable.

In reply, Hemlock asserts that the Staff's approach does not reflect Consumers' cost to serve each rate class, and that Consumers is using the correct allocation method. Hemlock argues that uncollectible expense has no relationship to each class's load characteristics, and the allocation of uncollectible expense should align with the function the expense is designed to support, namely customer relations, communication, and billing. 8 Tr 2130-2132. Hemlock argues that the Staff admitted that it had not reviewed Consumers' actual uncollectible expense by rate class. Exhibits HSC-13 and HSC-14.

ABATE argues in replies to exceptions that the evidence supports the ALJ's analysis, and that the Staff's proposal would divert uncollectible expense from the responsible class. In ABATE's opinion, other classes should not have to subsidize the costs associated with bill payment failures by one class.

Also, in reply, Consumers again refers to the fact that its analysis shows that 91% of electric write-offs during the last five years originated in the residential class. 5 Tr 559. Consumers points out that the Staff's proposal results in assigning some uncollectible expense to, for example, street lighting customers and non-jurisdictional customers, who almost never default. 5 Tr 560.

The Commission adopts the ALJ's findings and recommendation. This issue has been addressed in numerous recent orders where the Commission has considered and rejected the Staff's proposal to spread this cost to all customers rather than focusing on the class responsible for the bulk of the expense, and the Commission finds that the Staff has offered nothing new in this case. December 11 order, p. 114; December 9 order, p. 57; and January 31 order, pp. 102-103.

D. Demand Response Allocator

The DR revenue requirement allocator proposed by Consumers is based on CWIP. The Staff proposed an allocator based on "total expenses functionalized to production as a base to develop the allocator." 8 Tr 2686. In response, Consumers proposed a revised allocator closer to the Staff's proposal. The ALJ found that the two proposals produced similar results and recommended that the Commission approve Consumers' second proposed allocator. PFD, p. 145. No party filed an exception. The Commission adopts the ALJ's findings and recommendation.

E. Class Loss Factor

Class loss factors are used to calculate allocation factors. Hemlock argued that the class loss factors contained in the demand and energy allocations should be based on a three-year average rather than on the 2013 loss study. 8 Tr 2086.

The ALJ found that Consumers was correct in using the 2013 loss study because it is the most recent Commission-approved study, and the same factors were used in determining total generation requirements. PFD, p. 147; 5 Tr 563.

In exceptions, Hemlock argues that the 2013 study is outdated, and that use of the three-year average loss data would make the loss factor consistent with the three-year average used to develop demand and energy allocations. Hemlock asserts that Consumers' more recent 2014 loss study shows that the company's losses were greater in 2012 and 2014 than in 2013, and argues that 2013 data alone does not reflect Consumers' actual current losses. Hemlock avers that the ALJ failed to recognize that the 2014 loss study was introduced by the intervenors and admitted as Exhibit HSC-5. Hemlock argues that the three-year average should be used to avoid single-year anomalies and for consistency with the demand and energy allocators used by Consumers in the COSS.

In reply, Consumers argues that the 2013 study is the most recent Commission-approved study, and that the 2014 study is unapproved.

The Commission agrees with the ALJ. The 2013 loss study is the most recent approved study, and was used to determine Consumers' total generation requirements. November 19 order, p. 92; 5 Tr 563. Hemlock failed to demonstrate that the 2013 study was flawed, and the 2014 loss study that Hemlock favors actually reflects a four-year average of 2011-2014. Exhibit HSC-5, p. 9. The Commission finds that the 2013 loss study should form the basis for the class loss factors.[4]

X. <u>RATE DESIGN AND OTHER TARIFF ISSUES</u>[5]

A. Rate Design

1. Residential Rate RT

Residential Service Time of Day Rate RT (Rate RT) offers customers TOU pricing. Consumers proposed to close this rate to new business, because its new Residential Dynamic Pricing Rates (Rates RDP and RDPR) will be available to all customers with a smart meter pending approval in this case. 7 Tr 1315. The Staff countered that the rate should remain available until the installation of AMI is complete. 8 Tr 2660-2661.

The ALJ agreed with Consumers that the rate should be closed to new business, finding that closing the rate now will avoid future confusion between this rate and the Residential Dynamic Pricing Rates, and that customers currently on the rate will have adequate time to move to another rate option before Rate RT is finally eliminated for existing customers. PFD, p. 149; 7 Tr 1335.

In exceptions, the Staff argues that it is premature to close this rate to new business because that will discourage customers from enrolling in TOU rates while the AMI installation is still underway. The Staff contends that new customers may not wish to be subjected to the critical peak components of the other current TOU rate options of Rates RDP and RDPR.

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[4] Hemlock also argued that a 2012 class peak value should be utilized. Consumers agreed, but contended that the suggested value was inaccurate, and proposed a correction to Hemlock's correction. The ALJ agreed with Consumers and found that the company provided the correct class peak for use in calculating Allocator 127. PFD, p. 148; 5 Tr 564. No party filed an exception and the Commission adopts the ALJ's findings and recommendation on this issue.

[5] Minor tariff changes that were not disputed by the parties, and not addressed in the PFD or exceptions, are approved.

8 Tr 2660-2661. The Staff notes that whether or not Rate RT is closed has no bearing on the amount of time current customers have to find another rate option.

In reply, Consumers characterizes the Staff's concerns as speculative. Consumers states that it offers other residential TOU options.

The Commission agrees with the Staff. In the absence of Rate RT, new customers who are interested in a TOU rate might be forced onto Rate RS if they do not wish to be subject to the critical peak requirements of the other TOU rate options. 8 Tr 2660-2661. As the Staff points out, Rate RT is a better reflection of the cost to serve than Rate RS. The Commission finds that Rate RT should remain open to new business until the AMI installation is complete and the Residential Dynamic Pricing Rates are available to all customers with a smart meter.

2. Residential System Access Charge

The residential system access charge (also known as the customer charge) is currently $7.00 per month. Consumers proposed to increase it to $7.75 per month based on increased costs. 7 Tr 1312; Exhibit A-11. Consumers argued that the Commission's 1970s precedent on this issue is outdated, and that the company's proposed charge is cost-based and includes consideration of charges that arise from customers connecting to the system. 5 Tr 561-562.

The Staff argued that the increase is excessive and results from Consumers' inclusion of improper costs such as uncollectibles, taxes, and depreciation costs. 8 Tr 2687-2688. The Staff contended that the Commission has long held that not all customer-related costs should be recovered through the customer charge, but rather only those costs that are directly related to supplying service to customers. The Staff argued that the correct customer charge is $6.00 per month, but it does not oppose retention of the current charge. MEC/NRDC/SC agreed with the Staff.

The ALJ initially appears to partly agree with Consumers, and recommends that the Commission adopt “the $7.50 monthly system access charge, which was developed under the customer labor ratio that determines the customer-related expenses.” PFD, p. 147. (No party advocated for a $7.50 customer charge.) However, the ALJ later found that “it is reasonable to leave this charge at the $7.00 per month currently embodied in the Company’s rates.” PFD, p. 149.

In exceptions, MEC/NRDC/SC state that they support the ALJ’s ultimate conclusion to retain the current customer charge. MEC/NRDC/SC point out that Consumers’ calculation of the charge included general and common depreciation, and general and common property tax – categories that are not normally included in calculation of the customer charge. 5 Tr 561-562; 8 Tr 2687. Referring to the Staff’s testimony, MEC/NRDC/SC argue that while these costs might be considered to be fixed, they do not vary with the number of customers and are not incurred directly as a result of connection to the system. 8 Tr 2688. MEC/NRDC/SC argue that the method has not changed, and that the Commission rejected a proposal to include costs other than marginal costs in DTE Electric’s 2015 rate case. December 11 order, pp. 119-120.

The Staff argues in exceptions that the expenses included by Consumers in calculating its increased charge, such as uncollectibles, have been found to be not marginal, in that they are not affected by the total number of customers on the system. The Staff contends that its proposed customer charge (the current charge) includes only costs that have been repeatedly found to be directly associated with customers attaching to the system.

In exceptions, Consumers contends that the ALJ agreed with the company that the charge should be increased and that the later contradiction was in error. Consumers argues that in no case should be charge be set below the current $7.00 per month. Consumers’ exceptions, p. 90, n. 9.

In reply, the Staff argues that the charge should remain unchanged. The RCG and MEC/NRDC/SC indicate support for the Staff's position.

Consumers argues in replies to exceptions that "inclusion of customer administrative and general expenses, general and common depreciation, and general and common property tax in the residential customer charge is appropriate because they are directly related to personnel assigned to customer accounts and customer service." Consumers' replies to exceptions, pp. 37 and 92; 5 Tr 561-562. Consumers contends that uncollectible expense is also directly related to the number of customers and should be included.

The Commission agrees with the ALJ's latter conclusion that it is reasonable to retain the current charge. The Commission does not find its precedent outdated, and at this time, continues to support a customer charge based on marginal costs that are directly related to supplying service to customers. *See,* May 10, 1976 order in Case No. U-4771, Attachment A; January 18, 1974 order in Case No. U-4221, p. 30; December 11 order, pp. 119-120; November 19 order, p. 102; December 9 order, pp. 65-66; and January 31 order, pp. 107, 110; 8 Tr 2687-2688. Therefore, the Commission approves a residential system access charge of $7.00 per month.

3. Senior Citizen and Residential Income Assistance Rates

Consumers proposed to increase the RIA credit to $7.75 per month, and increase the RSC credit to $3.88 per month, in order to track the company's request with respect to the system access charge. The Staff opposed these changes.

Based on his decision to retain the current system access charge, the ALJ found that the RIA and RSC credits should remain at $7.00 and $3.50 per month (100% and 50% of the customer charge), respectively. PFD, p. 150.

In exceptions, Consumers argues that the ALJ's conclusion on these rates conflicts with his earlier ruling that the customer charge should be increased to $7.50, and that he intended to recommend approval of the higher RIA and RSC credits.

Based on its approval of the $7.00 customer charge, the Commission also retains the current RIA and RSC credits.

4. Residential Electric Vehicle Rates and Dynamic Pricing Pilot Rates, and Direct Load Management Program

Consumers proposed to retain the existing rate design approved for Rates REV-1 and REV-2, and proposed that Rates RDP and RDPR should act as standalone rates with the removal of the "pilot" designation. The Staff and the ALJ agreed. Likewise, all parties agreed that the name of the Direct Load Management Program should be changed to the Peak Power Savers Program, and that the credits associated with that program should be handled in the same manner as the interruptible credits for its general service primary demand rate (Rate GPD). The ALJ recommended adoption of these changes as well. No party filed an exception, and the Commission adopts the ALJ's findings and recommendations.

5. Rate GPD Issues

a. Joint Ownership Substation Credit

Hemlock proposed a change to the calculation of Consumers' joint ownership substation credit for Rate GPD Voltage Level 1 customers, to allow the credit to offset the maximum demand charge. 8 Tr 2093-2096. Consumers countered that its proposed credit is cost-based and serves both transmission and subtransmission voltages. 7 Tr 1339.

The ALJ recommended rejection of Hemlock's proposal, noting that Consumers has to construct and maintain its high voltage distribution lines at the 138 kilovolt (kV) level for all customers, and therefore all customers should contribute to the associated costs. PFD, p. 151.

In exceptions, Hemlock states:

> There are Rate GPD Voltage Level 1 customers, such as HSC, who own their own substations and for whom Consumers does not have investment in line conductors, line poles, line transformers, etc., to provide service. Some Rate GPD Voltage Level 1 customers are connected to the bulk transmission system owned by Michigan Electric Transmission Company, LLC. These are "transmission interconnect" customers. For these customers, Consumers' proposed substation ownership credit is not reasonable because it results in these customers paying for distribution plant not used to serve them. To correct this deficiency, HSC recommends that the substation ownership credit provision be amended to include the same transmission interconnect credit available to Consumers customers on Rate GSG-2.

Hemlock's exceptions, p. 18. Hemlock contends that it is seeking the same transmission interconnection credit as is provided to Rate GSG-2 customers, and that its proposal still requires the customer to pay for metering and other distribution-related costs through the system access charge. 8 Tr 2093-2096. Hemlock explains that a customer owning a substation that is not transmission interconnected will receive the credit proposed by the company, and a customer owning an interconnected substation will receive the higher credit because in that circumstance, the company "has no distribution investment other than metering, telemetry facilities and associated wiring." Hemlock's exceptions, p. 21.

In reply, Consumers reiterates that its proposal is cost-based, and that Hemlock ignores the fact that Consumers must construct and maintain high voltage lines at the 138 kV level of service for all customers. 7 Tr 1339. Consumers asserts that all customers who use the system should contribute to the cost. Consumers contends that Hemlock and other Rate GPD Voltage Level 1 customers are not transmission interconnected in the same way as customers who qualify for the Rate GSG-2 transmission interconnect credit, and thus should not receive the same treatment.

The Commission agrees with the reasoning of the ALJ, and adopts his findings and recommendation. Hemlock's proposal would effectively eliminate distribution charges for Rate

GPD Voltage Level 1 customers. 7 Tr 1339. However, the Commission finds that Hemlock has raised some legitimate concerns that were not completely addressed by Consumers, and recommends that this issue be explored more fully in the company's next general rate case.

b. Rate GPD Capacity Charges

Hemlock and Kroger proposed a change to the Rate GPD rate design to allow for the collection of 85% of capacity charges through the on-peak demand charge, rather than the 75% proposed by Consumers. The company opposed the intervenors' suggested change, arguing that it benefits high load factor customers on Voltage Level 1 only. 7 Tr 1339.

The ALJ found that the intervenors did not provide sufficient evidentiary support for the proposed change. PFD, p. 152; 8 Tr 2090, 2399-2400. The ALJ finds that the intervenors' proposed change is not revenue neutral, and that Consumers' proposal comports with the Commission's most recent ruling in Case No. U-17735.

Kroger argues in exceptions that the ALJ failed to address the substance of Kroger's and Hemlock's arguments. Kroger explains that the proposed change is revenue neutral to Consumers, though it would impact individual customers' rates. Kroger asserts that the current rate design sets demand charges below cost and energy charges above cost, thus creating a subsidy for lower load factor GPD customers. Kroger contends that its proposal would more closely align rates with cost causation, and would reduce the subsidy. Kroger maintains that regardless of the allocation method chosen, Consumers should be required to collect 85% of allocated capacity costs through the summer and winter on-peak demand charges for Rate GPD Voltage Level 3. 8 Tr 2399-2400.

In exceptions, Hemlock contends that, for Rate GPD Voltage Level 1 customers, 85% of demand costs should be collected in demand rates. Hemlock asserts that this moves rates closer to cost causation while avoiding rate shock, and that Hemlock's proposal is revenue neutral to

Consumers. Like Kroger, Hemlock maintains that Consumers' rate design creates an intra-class subsidization among large industrial customers, whereby high load factor customers subsidize lower load factor customers. Hemlock contends that this prevents cost-based rates, and prohibits economic development. Hemlock asserts that eventually 100% of demand costs should be recovered through demand rates. Hemlock refers to Exhibit HSC-8 which depicts the rate impact of its proposal, and argues that the increase on low load factor customers is reasonable (8.63% assuming Consumers' full rate request was granted).

In reply, Consumers argues that its 75% proposal balances the considerations of rate impact, cost causation, promotion of efficiency, and ensuring that the revenue requirement is collected. 7 Tr 1339.

The Staff argues in replies to exceptions that 75% is the appropriate level of capacity costs to be collected through the power supply demand charge for this rate. The Staff contends that Consumers' proposal considers cost causation and "the rate impact on all Rate GPD customers, not just customers with high load factors." Staff's replies to exceptions, p. 55. The Staff also argues that Consumers' rate design is appropriate because rates must be equal to the cost of service by rate class, not by rate schedule or rate component. *See*, MCL 460.11(1).

The Commission agrees with the ALJ and the Staff. In a previous discussion of this issue (where Hemlock advocated for 100%), the Commission found that "it is reasonable to consider rate impacts when changing rate design." November 19 order, p. 105. Hemlock and Kroger have provided nothing new in this record to persuade the Commission to move beyond 75% of capacity costs collected through the demand charge. Nor have they convinced the Commission that the differing voltage levels within this rate should be treated differently in order to comply with the cost-based rate statutory mandate. As the Staff notes, MCL 460.11(1) speaks in terms of "each customer class," and the revised version approved in Act 341 speaks in terms of each customer class or sub-class. Rate GPD Voltage Levels 1 and 3 are neither a class nor a sub-class. The Commission approves Consumers' proposed Rate GPD capacity charge.

c. On-Peak Demand Ratchet

Consumers proposed reinstating an on-peak demand ratchet that was previously utilized for the class of customers that take service under Rate GPD. The ratchet entails calculating demand based on the highest on-peak demand created during the billing month, but never billing at less than 60% of the highest on-peak demand of the preceding billing months of June through September, nor less than 25 kW. 7 Tr 1320. ABATE argued that Consumers failed to establish that the ratchet is necessary. 8 Tr 2012. Hemlock and Kroger argued that Consumers failed to estimate the additional billing units that would be produced. 8 Tr 2097, 2401.

The ALJ found that Consumers established that the ratchet helps to ensure that capacity costs are paid by the customers for whom the capacity has been obtained. The ALJ also noted Consumers' agreement that the final rate design should include the additional billing units and revenue impacts associated with the ratchet mechanism. PFD, pp. 152-153; 7 Tr 1320, 1340. The ALJ recommended that Consumers' rate design for Rate GPD be approved.

ABATE argues in exceptions that this rate has never had a demand ratchet, Consumers failed to demonstrate the need for it, and demand ratchets have the potential to charge for power not taken. ABATE contends that Consumers failed to show that it experienced any problems associated with collecting the full revenue amount associated with this rate without the demand ratchet, nor did the company disclose how the billing determinants for Rate GPD would change. ABATE asserts that if the demand ratchet is approved, it should be only in conjunction with approval of the 4CP 100 allocation method.

In exceptions, Hemlock points out that Consumers frequently files rate cases (six in the last nine years), rendering concerns about regulatory lag irrelevant. Hemlock argues that a ratchet mechanism is unnecessary for ensuring that Consumers has an opportunity to recover its demand costs from these customers.

In reply, ABATE supports Hemlock's position and reiterates the arguments set forth in exceptions.

Consumers explains in replies to exceptions that while it is true the ratchet was never used with Rate GPD before, the ratchet was applied to the prior primary service rate. Consumers argues that capacity costs will increase in the future, and the ratchet will ensure that those costs are paid for by the customers for whom the capacity has been secured. Consumers indicates that it agrees with the ALJ that the final rate design should include the additional billing units and revenue impacts, consistent with how rates are set after a final Commission order.

In replies to exceptions, the Staff argues that ABATE and Hemlock offer nothing new in their exceptions, and that the ALJ correctly recommended approval of the charge provided that Consumers properly accounts for the additional billing units and revenue the ratchet would produce. The Staff asserts that the ratchet will "help ensure that the Company can properly plan for capacity and that capacity costs are paid by those customers for whom capacity is secured." Staff's replies to exceptions, p. 56.

The Commission agrees with the ALJ and the Staff. While it is true that regulatory lag is not a concern (particularly in light of Act 341), Consumers is not arguing that the problem is failure to recover the cost, but rather that the appropriate customers are made responsible for the cost. Consumers demonstrated that the ratchet will simply help ensure that capacity costs are paid for by the customers for whom the capacity was secured.

6. Rate GSG-2 Issues

a. Rate Design

ABATE proposed that Consumers' self-service power and standby service rate (Rate GSG-2) be changed to reflect the MISO planning resource auction clearing price (ACP); or, if that price is currently considered to be "unreasonably suppressed," then the MISO cost of new entry (CONE) should be adopted, with migration to the ACP in the future. 8 Tr 2030-2035. Consumers countered ABATE's proposal, arguing that the ACP has no bearing on this rate, and would not reflect the company's embedded cost of capacity. Consumers argued that it has generating capacity available to serve standby customers, and thus, standby customers should pay a demand rate based on the company's embedded cost of capacity on a per kW basis. 7 Tr 1341-1342.

The ALJ agreed with Consumers that the rate should reflect the embedded cost of capacity on a per kW basis, and that ABATE's proposal should be rejected because it would not reflect the company's embedded cost of capacity. PFD, p. 155. The ALJ found that the ACP "does not represent a per day cost, and thus has no bearing on the GSG-2 demand charges." *Id.* The ALJ also noted Consumers' agreement with the Staff to modify the tariff language to clarify that the capacity costs are prorated for customers based on the number of on-peak days per month in which standby power was actually provided.

In exceptions, ABATE avers that Consumers' proposal for this rate will nearly double the current Rate GSG-2 power supply standby service charges. ABATE argues that the GSG-2 demand charges should reflect the MISO ACP, which represents the incremental cost to provide standby service. ABATE states:

> This approach fully provides for Consumers' costs of service for three reasons: (i) Consumers does not need to include standby service demand in its long-term resource plan and does not incur any generation costs to provide service; (ii) the daily demand charges provide sufficient revenue to Consumers necessary to cover

> its MISO capacity costs to provide the service; and (iii) all MISO transmission charges are passed through to the customer and the customer is responsible for delivery charges. While the MISO ACP would fully cover Consumers' costs to provide the service, as a conservative migrational step toward that value, ABATE recommended that in this proceeding the MISO [cost of new entry] CONE price, which is the highest value that the MISO ACP can clear at, be used in place of the actual MISO ACP.

ABATE's exceptions, p. 15. (Notes omitted.) ABATE urges the Commission to adopt the CONE price in this proceeding and consider the ACP in the future. At a minimum, ABATE argues, the Commission should reject Consumers' proposal (presented in rebuttal testimony) to base power supply demand charges on Consumers' embedded cost of capacity and instead retain the current approach, which bases the charges on the highest contracted capacity purchase in that month, but with the on-peak day pro-rata clarification adopted by the ALJ.

Hemlock asserts in exceptions that Consumers failed to propose changes to Rate GSG-2 in its direct case, and instead first proposed the changes on rebuttal. 7 Tr 1341. Hemlock points out that proper rebuttal testimony refutes the direct case, and is not the forum for the presentation of new rate proposals. Hemlock contends that standby rates should not be changed, in any case, until the Staff completes the holistic review taking place in the Standby Rate Working Group and makes recommendations. *See,* November 19 order, p. 111. Hemlock further asserts that standby rates should not reflect Consumers' embedded capacity costs because the company "does not need to include standby demand in its capacity plans." Hemlock's exceptions, p. 26.

In reply, ABATE supports Hemlock's position and repeats its arguments, asserting that if capacity is not procured to provide standby service, it should not be included in the cost of providing such service.

Consumers argues in replies to exceptions that it is required to plan and secure capacity for all customers, including those who take service on a standby rate, and the MISO ACP does not reflect the cost of obtaining capacity for standby customers. Consumers asserts that historical standby demand should form the basis for determining capacity requirements because it represents expected use. Consumers notes that the MISO ACP is sold as an annual product, not as a daily product.

Consumers also argues that its new proposal regarding embedded cost was proper rebuttal, because it contradicted ABATE's proposal by explaining the proper way in which the Rate GSG-2 capacity costs should be calculated. Consumers points out that it is the supplier of last resort and must plan for the capacity of all retail customers, and argues that the embedded cost on a per kW basis makes most sense.

In reply, the Staff argues that ABATE's proposal would result in charges that create subsidies between groups of non-standby customers, and would fail to reflect the value of the service provided to standby customers. Staff's replies to exceptions, p. 57.

The Commission agrees with the ALJ and the Staff regarding ABATE's proposal. ABATE failed to demonstrate that either the MISO CONE or ACP is superior to historical standby demand for determining future capacity requirements. Neither MISO price reflects the cost of obtaining capacity for standby customers. However, because Consumers introduced the proposal to set the demand rate based on the company's embedded cost of capacity on a per kW basis on rebuttal, the Commission finds that it must be rejected. 7 Tr 1341-1342. Rather than simply a refutation of ABATE's proposal, Consumers presented a new concept for determination of the amount collected through this rate that was not presented in direct testimony, and the other parties were unable to rebut this testimony with witnesses or otherwise test the new concept. No party took issue with the agreed-upon clarification regarding proration and the Commission approves that change.

b. Rate GSG-2 Cost Study

The Staff proposed that, in its next rate case filing, Consumers provide a study that compares power supply revenue from Rate GSG-2 customers to power supply costs caused by these customers, in order to determine whether current demand charges reflect the cost to serve standby customers. 8 Tr 2713.

The ALJ recommended rejection of the Staff's proposal in light of the fact that Consumers is already participating in the Standby Rate Working Group convened pursuant to the November 19 order, which will require submission of a report. PFD, p. 155.

In exceptions, the Staff contends that a study comparing the power supply costs and revenues associated with standby customers should be required for the next rate case, because the working group does not have access to this data "split out specifically to standby customers." Staff's exceptions, p. 38.

Consumers argues in replies to exceptions that an additional study is unnecessary and that the Staff previously expressed a preference for studying this issue in a workgroup rather than in a rate case. Consumers notes that an additional analysis "could be substantial." Consumers' replies to exceptions, p. 40.

The Commission approves the Staff's request. The report expected from the Standby Rate Working Group is of a more holistic nature, as both the Staff and the company pointed out in post-PFD briefing. It is reasonable to expect Consumers to support its assertion that this rate is cost-based by providing information comparing revenues to costs in its next rate case filing.

7. Interclass Crossing-Point Adjustment

The Staff agreed with Consumers' proposed interclass crossing-point adjustment, which maintains the crossing points between Rates GPD and GP, but argued that in its next rate case, Consumers should be required to make a proposal to bring these rates to their relative cost to serve. 8 Tr 2673.

The ALJ found that the "Interclass Crossing Point adjustment will establish the breakeven point, and as the Commission held in U-17735, is reasonable. Therefore, the adjustment should be approved, and should not be precluded from approval in future rate cases." PFD, p. 156. The ALJ did not address the cost of service issue.

In exceptions, the Staff states that it does not take exception to the ALJ's decision to adopt the adjustment for the instant case, but argues that the additional cost of service analysis should be required for the next rate case. The Staff notes that the crossing-point adjustment has grown larger in recent rate cases, and recommends that the Commission require Consumers, in its next rate case, to provide the evidence necessary to show how the adjustment may be eliminated.

In reply, Consumers argues that no study is necessary, and that the company should be able to continue to use the same adjustment in the future.

The Commission agrees with the Staff and the ALJ, and adopts Consumers' proposed adjustment for this case, as well as, the Staff's recommendation that, in the next general rate case filing, Consumers provide the evidence necessary to show how the adjustment may be eliminated.

8. Educational Institution Rates

Educational institutions (EI) must be charged retail rates that reflect their cost of service pursuant to MCL 460.11(9). In this case, Consumers proposed to separate EI customers into their own rate class, and accept the results if the separation produced a lower cost for EI customers.

The Staff took issue with Consumers' proposed rate design, arguing that EI rates should be set in the same manner as they were set in the company's last rate case:

> In that case, it was determined that Education Institution customers were not their own separate rate class and were charged rates that reflected cost to serve for each

> of the standard rates that Education Institution customers take service under. The fact that the results of splitting out the customers is so inconsistent shows that the customers are not served differently enough from those on the standard rates so as to merit a separate rate class. The method approved in U-17735 simply resulted in a credit on the distribution rates for Education Institution customers to remove the subsidies for Income Assistance and Senior Citizens, which these customers are not required to pay (Order, U-17735, Page 102).

8 Tr 2670-2671. Consumers countered that the Staff's proposal would prevent some customers from receiving a power supply credit.

Finding that Consumers' proposal should be adopted, the ALJ stated:

> Staff's proposal would result in some educational customers paying higher rates, relative to other classes, in some rate schedules. Conversely, the Company's proposal to split the institutions in their own class, and then determine the cost of service and apply a credit if there is a cost benefit relative to the total rate schedule's cost of service, complies with the express language of MCL 460.11(9). Therefore the Company's proposed Educational Institution Service provision should be adopted.

PFD, p. 158.

In exceptions, the Staff argues that Consumers' proposal produces inconsistency, so that when "it is in an educational institution's benefit, the Company would give them a power supply and distribution credit, but when an institution's power supply charge is more than it would have been without the split, the Company would treat the institution like the rest of its original class." Staff's exceptions, pp. 30-31; 8 Tr 2670. The Staff argues that the company is choosing when to apply rates that reflect the EI's cost to serve, which does not comport with the statutory requirement. The Staff supports the cost-based approach that was adopted in Case No. U-17735 and notes that no party argued against that approach.

In reply, Consumers argues that its proposal is consistent with the statute because it focuses on the actual cost of providing service. Consumers states that splitting EIs into their own class "allowed the Company to establish education credits within the rate design to discount the standard rate and reflect educational institutions' actual cost of service – to the extent there was a cost benefit relative to the total rate schedule's cost of service." Consumers' replies to exceptions, p. 34.

The Commission agrees with the Staff. MCL 460.11(9) mandates that EIs shall pay their cost to serve, and provides no exceptions. While Consumers' proposal may be well-intentioned, the Staff's proposal is consistent with Commission precedent and the requirements of the statute with respect to cost-based rates. Regarding the mechanics of the proposal, Consumers' witness stated:

> [T]o the extent that the cost of service shows that an educational customer class should receive lower power supply charges, the Company applied a credit to achieve the lower rate. This gets these customers classes to their cost to serve. In some rate schedules, the cost of service showed a higher cost to serve for the education class than for the rest of the class. Therefore, for these customers, only the distribution credit is applied which represents removal of low-income and senior subsidies. The fact that some classes did not see a benefit in the power supply should not impact the classes that did.

7 Tr 1335-1336. This testimony, as well as the Staff's analysis of the effect of the split, indicates that separation of these customers into their own rate class does not provide a better match with their cost to serve; if it did, Consumers would presumably apply the credits consistently.

XI. OTHER ISSUES

A. Advanced Metering Infrastructure Opt-out Tariff

Consumers proposed to increase the AMI opt-out charges based on increased costs of service. 7 Tr 1436-1441; Exhibit A-65. Consumers argued that, rather than the 1.5% of customers originally projected, only about 0.6% of customers have chosen to opt out of the smart meter program. 7 Tr 1439. Consumers noted that currently, the up-front cost for a customer who chooses to retain their existing meter prior to smart meter installation is $69.39, the up-front cost for a customer who requests to replace an existing smart meter with a legacy meter is $123.91, and the ongoing monthly cost of operations for opt-out customers is $9.72 per month. Based on this lower participation level, Consumers now proposes an up-front cost of $163.82 for customers who retain their existing meter (a $94 increase), $219.48 for customers who choose to have their smart meter replaced with a legacy meter (a $95 increase), and a $19.43 monthly opt-out charge. Exhibit A-65. On rebuttal, Consumers revised the proposed monthly charge to $15.48 after removing the meter reading expense and the AMI capital and investment expense (credits that were previously approved in Case No. U-17087), that amounts to a $5.76 increase. Exhibit A-120.

Consumers stated that full deployment of AMI will be completed by the end of the test year, making this the last case in which the Commission can address the implementation costs. Consumers further contended that as of January 25, 2016, the acceptance rate stabilized at 99.49%, and has not dropped below 99% since 2013. 7 Tr 1436-1445. Additionally, Consumers requested that the Commission consider eliminating the offsetting credit approved in Case No. U-17087 that allows opt-out customers to avoid the costs of AMI infrastructure (capital and investment) that are embedded in base rates. Consumers argued that it is poor ratemaking policy to allow a small group of customers to evade payment for a Commission-approved investment that has become standard utility equipment. If the rate base credit remains in place, Consumers proposed an increase from $1.00 per month to $3.60 per month. 7 Tr 1449-1450; Exhibits A-119 and A-120.

The Staff opposed the tariff increases, arguing that they are premature and unsupported by the record evidence. 8 Tr 2700-2702. The Staff pointed out that AMI installation is still in progress, the total number of opt-outs will not be known until full deployment, and that an increase to the charges could affect the number of people who decide to opt out. The Staff also opposed the proposal to eliminate the AMI base rate credit.

The RCG argued that Consumers failed to support the proposed charges with sufficient evidence, and that opt-out charges should in fact decrease because only one annual meter reading is necessary for customers that self-read. Additionally, the RCG contended that the Commission should require Consumers to provide adequate advance notice that an AMI meter will be installed, and allow the installation only upon receipt of written permission from the property owner. *See*, Exhibit RCG-11. The RCG also argued, as it has many times before, that the Commission lacks jurisdiction to mandate a smart meter program, and that the Commission's AMI-related orders are unconstitutional.

The ALJ found that the notice that Consumers is currently providing to customers regarding AMI installation "goes well beyond Exhibit RCG-11, and is more than sufficient to inform customers of the nature of the program, including the ability to opt-out." PFD, p. 161; 7 Tr 1438-1439. The ALJ took note of the Commission's and Michigan Court of Appeals' decisions finding that the AMI meter is now standard metering technology and part of standard utility service. *See*, November 19 order, pp. 130-131; *Detroit Edison Co v Stenman*, 311 Mich App 367, 382; 875 NW2d 767 (2015). The ALJ also found that this proceeding cannot be used by the RCG to make a collateral attack on Commission and court orders that address the jurisdictional and constitutional arguments.

Turning to the tariff, the ALJ found that Consumers' proposed tariff change represents the cost to serve these customers and should be adopted. PFD, pp. 164-167. The ALJ determined that "Neither Staff nor the RCG presented any evidence that specific charges in the AMI tariff are inaccurate or do not represent the actual cost-of-service for the AMI opt-out program." PFD, p. 164. The ALJ referenced Consumers' evidence showing that it will utilize 21 full-time meter readers (previously estimated at 35) for monthly reading of an estimated 10,800 randomly-distributed non-transmitting meters under the 0.6% opt-out estimate. 7 Tr 1439; *see*, Mich Admin Code, R 460.113(1) and 460.115. The ALJ pointed out that it is possible that no opt-out customer will enroll in the self-read program, and that Consumers must plan accordingly. With respect to the AMI base rate credit, the ALJ found that the credit should remain in place based on Commission precedent, but that it should increase as proposed by Consumers concurrent with the increase in the opt-out tariff charges. Exhibits A-65 and A-120.

In exceptions, the Staff argues that the tariff should not be increased. The Staff extrapolates a variability in the acceptance rate of approximately 0.5% over the time period shown in the graph at 7 Tr 1446, and contends that the 0.5% variability is significant in the context of such a small pool of customers opting out (approximately 0.6% of all customers receiving a new meter). The Staff maintains that the increases are premature and that Consumers failed to prove that the new tariff would be cost-based. The Staff also objects to the fact that Consumers' evidence attempting to justify the increase and incorporating the currently-mandated offsets was only offered on rebuttal (Exhibit A-118), allowing no opportunity to test the evidence. In any case, the Staff contends, Exhibit A-118 offers no explanation for why the Smart Meter Deployment Exceptions Process line item (lines 2 and 9 on Exhibits A-65 and A-120) quadrupled for both categories of up-front costs (going from \$19 to \$114, and \$34 to \$129). The Staff also notes that by not calculating the amount of the offsetting credits until the rebuttal phase of the case, the other parties had no opportunity to test this evidence.

In exceptions, the RCG argues that the ALJ erred. The RCG points out that Consumers offered no COSS on these costs, and asserts that the proposed charges punish opt-out customers. The RCG contends that self-reads combined with participation in the budget payment program would protect the company and obviate the need for any meter reading expense. The RCG argues that the lower number of opt-out customers should correspond to lower costs rather than higher, and that the surcharge should be eliminated for customers who agree to self-read. In any event, the RCG contends, opt-out customers do not cause costs because they pay the rate base amount, the ROE (on that amount), the O&M expense, and the taxes associated with the new infrastructure.

The RCG reiterates that customers do not receive adequate notice of the installation of the smart meter, and that advance written notice should be required.

The RCG further asserts that the Commission lacks jurisdiction with regard to AMI-related costs and tariffs, and that the Commission's AMI-related orders are unconstitutional.

In exceptions, Consumers argues that the offsetting credit should be removed. Consumers notes that the costs of the AMI infrastructure have been approved in a series of rate cases (2009, 2010, 2012, 2013, and 2015) and have been affirmed by the Court of Appeals. Consumers reiterates that smart meters are now considered standard metering equipment, and that a small percentage of the customer base should not be allowed to evade payment for a portion of this approved investment. The company asserts that the opt-out option is extraordinary, and that opt-out customers still receive numerous benefits from the AMI infrastructure.

In exceptions, the Attorney General opposes an increase to the opt-out fee and supports the Staff.

In reply to Consumers, the Staff argues that the offset continues to be necessary to ensure that opt-out rates are cost-based.

The RCG argues in replies to exceptions that Consumers presented no qualified COSS witness to identify the specific costs attributable to opt-out customers. The RCG also asserts that analog meters remain standard metering equipment, and that, in any case, Consumers does not explain how making something "standard" establishes an adequate cost basis for a proposed charge. The

RCG contends that opt-out customers save Consumers the cost of the smart meter and the cost of its installation. The RCG again refers to the ability to self-read, combined with the budget payment plan option, as providing a way to dispense with any alleged opt-out cost.

In replies to exceptions, Consumers contends that it provided ample evidence in its testimony and exhibits to support the increase, and that no party presented contradictory evidence. *See*, 7 Tr 1436-1437; Exhibits A-65 and A-118. Consumers also points out that the existing credit in the current opt-out charge is designed to remove the costs of the infrastructure from opt-out customers' rates, despite the fact that those customers receive benefits from AMI. Consumers contends that R 460.113 contains express encouragement for utilities to perform actual meter reads, and that no party provided evidence showing that Consumers could avoid meter reading costs by allowing customers to self-read.

Consumers maintains that it provides ample notice prior to the installation of smart meters and has developed an extensive customer communication process that has been noted by the Commission and found to constitute consent. November 19 order, p. 130-131. *See, Stenman*, 311 Mich App at 382.

Finally, Consumers objects to the RCG's attempts to re-litigate jurisdictional and constitutional issues that have been decided by the Commission and either affirmed on appeal, or are under active appeal.

The Commission agrees with the ALJ that Consumers' advance notice program is adequate to provide customers with notice of pending smart meter installation and how to obtain more information either online or over the phone. 7 Tr 1438-1439. Advance notification is by postcard (30 days before installation), letter (14 days before), and phone call (the Saturday before) to the individual customer. *Id.* The smart meter is now standard metering technology and part of standard utility service. *Stenman*, 311 Mich App at 382. The Commission is, once again, not persuaded that Consumers' notification program is inadequate to provide sufficient warning, or that written consent is required. November 19 order, pp. 130-131.

The Commission also agrees with the ALJ's findings and recommendations regarding the RCG's jurisdictional and constitutional arguments, and does not find it necessary to repeat the conclusions of the many orders and cases wherein the RCG's claims have been thoroughly considered. *Pennwalt v Public Service Comm*, 166 Mich App 1, 9; 420 NW2d 156 (1988); *Stenman, supra; In re Application of Detroit Edison Co to Implement Opt-Out Program*, unpublished opinion per curium of the Court of Appeals, issued February 19, 2015 (Docket Nos. 316728, 316781); *Attorney General v Public Service Comm*, unpublished opinion per curiam of the Court of Appeals, issued April 30, 2015 (Docket No. 317456); November 19 order, pp. 114-132; and December 11 order, pp. 91-110.

The Commission rejects several of the RCG's other arguments. The RCG contends that opt-out charges are duplicative because these customers are already paying for the AMI program through base rates. The Commission has previously rejected this argument, citing to the Staff's testimony that it is "demonstrably false." November 19 order, pp. 129-130 (quoting from 9 Tr 1868 in that docket). The RCG's contention is belied by Exhibit A-120 in this case, which shows the existing and proposed monthly credits for opt-out customers. These monthly credits protect opt-out customers from the meter reading expense and the AMI capital and investment expense that appear in rate base, by offsetting those expenses.

The Commission also rejects the RCG's arguments regarding the necessity for a COSS for these tariffs, because convincing evidence demonstrating the costs associated with the opt-out program was supplied in Case No. U-17087 and Case No. U-17735 (direct evidence). November 19 order, pp. 127-128.

In addition, the Commission has previously addressed the RCG's argument regarding self-reads, and rejected it. November 19 order, p. 128. As the Commission stated in Consumers' last rate case, self-reads are the exception, not the rule, and the RCG provided no evidence in this docket showing how many opt-out customers are providing self-reads or how often. *Id.* Finally, as the RCG is aware, the company may not require all opt-out customers to enroll in the budget payment plan. Consumers must plan its expense in a reasonable and prudent manner or risk having the expense disallowed in a rate case. Here, the cost that is built into the tariff is based on the notion that the company may have to read all of the analog meters, and does not assume that all opt-out customers will enroll in the budget payment plan. The Commission finds that this is reasonable and prudent planning.

The Commission, however, agrees with the Staff and the RCG on the issue of raising the opt-out charges. Consumers' direct evidence supporting the increases was scant. 7 Tr 1436-1441. The company's witness refers to Exhibit A-65, but this exhibit simply lists categories of costs, showing the existing and proposed costs by line item, but provides no tangible support for the increases. The testimony describes the nature of the up-front and ongoing monthly costs, but is silent on the basis for the proposed new charges. 7 Tr 1436-1437. More information was provided on rebuttal[6] in Exhibit A-118, but even that exhibit fails to explain why the "Systems Cost to Enable Process" increased by almost $100 per customer between Case No. U-17087 and

[6] The Commission notes that the sponsoring witness testified that he provided the same evidence as a workpaper in the company's original filing. 7 Tr 1447.

this case. Exhibit A-118, p. 2, n. 4; 7 Tr 1448.[7] That change alone raised the up-front cost for customers who opt out prior to the install, in this category, by a factor of six ($19 to $114). The supporting evidence simply does not justify a tariff increase of that magnitude.

Likewise, with regard to the monthly charge, the Commission is not satisfied that Exhibit A-118 answers all relevant questions. The rebuttal testimony provided by Consumers seems to focus on the up-front charges, and only offers that the proposed increases "are based on cost of service principles." 7 Tr 1444-1446. The discussion of the monthly charge contained in Exhibit A-118 does not address the Staff's question as to how to accurately determine the number of opt-out customers to divide the costs among. Given that the AMI installation is not yet complete, the proposed increases appear premature. January 31 order, p. 129. Moreover, the existing tariffs have been found, based on the evidence provided in Case Nos. U-17087 and U-17735, to be cost-based. June 28, 2013 order in Case No. U-17087, pp. 3-9; November 19 order, pp. 125-128. Accordingly, the Commission finds that the existing tariffs should remain in place, with the existing credit. The Commission adopts the Staff's recommendation that Consumers recalculate AMI opt-out charges either in its next general rate case following full deployment of AMI meters, or in a contested case filed six months following full deployment, whichever is sooner. 8 Tr 2701-2702.

[7] This is an element of the Smart Meter Deployment Exceptions Process, Exhibits A-65 and A-120, lines 2 and 9.

B. Emergency Electrical Procedures

Consumers proposed revisions to its Emergency Electrical Procedures Tariff to better align the tariff with MISO requirements. 8 Tr 1845-1846. No party opposed the revisions and the ALJ recommended that they be approved. No exceptions were filed. The Commission approves the revisions.

C. Experimental Residential Plug-in Electric Vehicle Charging Program Tariff

Consumers proposed changes to the Experimental Residential PEV Charging Program Tariff to eliminate the language for the now-expired reimbursement program, and to add language regarding an incentive. Consumers later withdrew its proposal for a PEV charging program, but argued that the Commission should approve the original version of the PEV tariff proposed in its initial filing.

The ALJ recommended that the language concerning the now-expired reimbursement program be removed. PFD, p. 168. No exceptions were filed, and the Commission approves this change.

The Staff proposed a change to the tariff language in schedule C4.4 to make it clear that sale-for-resale at an electric vehicle charging station is not regulated by the Commission as a sale of electricity by a public utility.

The ALJ did not address this issue.

In exceptions, the Staff notes that the ALJ did not address its proposal, but argues that the sale-for-resale issue should be decided. The Staff contends that it should be clear to the electric vehicle charging market that charging stations will not be treated as though they are regulated public utilities. The Staff advocates proposed language for revised schedule C4.4 that clarifies that neither the resale of Consumers’ electric service nor the sale of self-generated service at a public charging stations is subject to Commission regulation because these sales are being made into the competitive fuels market.

In exceptions and replies to exceptions, ChargePoint argues that the Commission should establish a regulatory exemption for electric vehicle charging stations by adopting the Staff's proposed modification to the C4.4 resale tariff, which would remove electric vehicle charging services from the resale prohibition. ChargePoint notes that the ALJ failed to address this issue, and argues that allowing for pricing of charging services by kWh will expand customer choice and innovation in the electric vehicle charging market.

In exceptions and replies to exceptions, MEC/NRDC/SC also note that the ALJ failed to address this "non-controversial" issue, and urge the Commission to adopt the Staff's proposed change to the C4.4 tariff language.

Consumers agrees in replies to exceptions that this revision to the C4.4 tariff language should be adopted.

The proposal indeed appears to be non-controversial, and the Commission agrees with the Staff that the sale of electricity by charging station owners should not be treated as a resale of electricity under the tariff, or as a sale by regulated utilities. This is a necessary change to the tariff language which the Commission approves.

D. Appeal of the Administrative Law Judge's Ruling on the Protective Order

On May 26, 2016, MEC/NRDC/SC filed a motion to compel discovery responses, seeking specific confidential information from Consumers pursuant to a protective order. According to MEC/NRDC/SC, they and Consumers had the same dispute in the company's last rate case, Case No. U-17735, and the judge in that case, Mark E. Cummins, entered a protective order granting MEC/NRDC/SC custody of specific confidential materials under reasonable time restrictions. MEC/NRDC/SC averred that in this case, its "proposed Protective Order, conform[s] to the order in Case No. U-17735 in all respects except case names and numbers," and requested that the ALJ approve its proposed protective order. MEC/NRDC/SC's motion to compel discovery responses, p. 5.

In response, Consumers noted that it agreed to provide the requested information, however pursuant only to its proffered confidentiality agreement. The company stated that MEC/NRDC/SC declined to execute the agreement because it contained a provision that would have required MEC/NRDC/SC to return or destroy the company's confidential information at the conclusion of this case. Consumers disputed the propriety of the protective order in Case No. U-17735 and MEC/NRDC/SC's conforming protective order in this case, and requested that the ALJ, instead, adopt the company's proposed protective order.

At a hearing on June 6, 2016, the ALJ granted MEC/NRDC/SC's request for a protective order, stating that:

> Counsel for a requesting Party may maintain a single confidential file of Protected Material beyond the resolution of this proceeding, provided that this Order will continue in effect with respect to the Protected Material for so long as it is retained by counsel for any requesting Party. If the Protected Material is relevant or reasonably calculated to lead to admissible evidence in another Commission proceeding, then it may be used in such a proceeding subject to the issuance of a new Protective Order in that proceeding. The terms of this Paragraph shall apply until the later of (i) the resolution of Consumers Energy Company's next general electric rate case conducted after Case No. U-17990, or (ii) the resolution of any and all Power Supply Cost Recovery or Power Supply Cost Recovery Reconciliation cases that may be filed before the resolution of the next general electric rate case. For purposes of this paragraph, the "resolution" of a case means the expiration of the period of judicial review of a final order of the Commission.

June 7, 2016 protective order in Case No. U-17990 (June 7 protective order), pp. 4-5.

In exceptions and pursuant to Rule 433(5) of the Rules of Practice and Procedure Before the Commission, R 792.10433(5), Consumers appeals the ALJ's decision. Consumers argues that the discovery information sought by MEC/NRDC/SC in this case is confidential, proprietary, and commercially sensitive business information and is the personal property of the company. Pursuant to statute and established case law, Consumers asserts that the Commission has no authority "to permit parties to retain discovery materials beyond the confines of the case for which it was produced." Consumers' exceptions, p. 96. To do so, Consumers avers, constitutes a taking of the company's personal property.

Consumers also argues that the Commission erred in the November 19 order when it upheld a similar protective order. According to the company, the Commission applied the wrong standard of review – abuse of discretion – to Judge Cummins' decision to enter a protective order. Consumers states that:

> The Commission in that case did not recognize that the authority and discretion to control discovery matters only operates within the confines of an appropriate case . . . . To the extent the ALJ's Protective Order purported to extend a possessory right over the Company's confidential information to third-parties outside of the confines of an MPSC proceeding, it was not a "discovery" matter at all. Therefore, the Commission should not have applied the deferential abuse-of-discretion standard.

Consumers' exceptions, p. 98. Because MEC/NRDC/SC claimed that abuse of discretion was the appropriate standard of review in replies to exceptions in Case No. U-17735, the company contends that it did not have an opportunity to dispute the claim in that case.

In this case, Consumers asserts that the ALJ entered a protective order based upon the erroneous ruling in Case No. U-17735. As a result, Consumers requests that the Commission reverse its decision in the November 19 order, overrule the ALJ's decision in the immediate case, strike paragraph 12 of the June 7 protective order, but otherwise preserve the June 7 protective order in all other respects.

MEC/NRDC/SC reply that the Commission should reject Consumers' appeal because this issue was recently decided by the Commission, this type of protective order has become common in Commission cases, and the terms of the protective order are narrowly tailored, limited in duration, and reasonable. MEC/NRDC/SC's replies to exceptions, p. 22.

MEC/NRDC/SC note that, according to Judge Cummins in Case No. U-17735, a protective order of this type is reasonable because efficiency is improved when the same parties have access to relevant materials in subsequent cases, thus reducing the number of discovery requests, discovery responses, and contested hearings. MEC/NRDC/SC also state that general rate cases, PSCR plan cases, and PSCR reconciliation cases "operate under relatively tight timeframes, making it important to have relevant material available rather than waiting for the discovery process. That concern will only become more severe, not less, with the shortening of rate cases from 12 months to 10 months as dictated by PA 341 of 2016." MEC/NRDC/SC's replies to exceptions, p. 20. In addition, MEC/NRDC/SC contend that an intervenor's right to retain confidential materials is narrowly tailored in the protective order because only counsel for the parties may retain one copy of the materials, the retention period is limited in duration, and the use of these materials in a subsequent case requires a new protective order. *Id.*, pp. 20-21.

MEC/NRDC/SC aver that the protective order expressly states that the "Protected Material shall remain the property of the Applicant," thereby eliminating Consumers' concern that the protective order is a taking of personal property. June 7 protective order, p. 3. Moreover, MEC/NRDC/SC argue that Consumers failed to cite any relevant precedent in support of its taking argument, and instead relies on "Michigan cases reciting well-known precepts about the bundle of property rights, but no Michigan cases having anything to do with discovery, let alone discovery involving regulated utilities." MEC/NRDC/SC's replies to exceptions, p. 21. MEC/NRDC/SC state that the only case regarding discovery cited by Consumers is from Texas and is irrelevant.

MEC/NRDC/SC disagree with Consumers' assertion that although the State Administrative Procedures Act allows agencies to adopt discovery and deposition rules appropriate to its "proceedings," this grant of authority cannot extend beyond a single proceeding. MEC/NRDC/SC's replies to exceptions, p. 22, citing Consumers' exceptions, p. 96. In MEC/NRDC/SC's opinion, the language cited by Consumers "refers to not a single proceeding, but to plural 'proceedings.' And . . . the conditions of the protective order are undoubtedly fashioned in a manner appropriate for Commission proceedings." *Id*., p. 22.

Regarding Consumers' claim that the Commission applied the incorrect standard of review – abuse of discretion – to Judge Cummins' decision to enter a protective order in Case No. U-17735, the Commission notes that the company failed to set forth what it believes to be the correct standard of review. Therefore, absent a persuasive contrary argument, the Commission affirms the November 19 order and finds that protective orders, like most pretrial matters, are reviewed for an abuse of discretion. *Briggs v Upjohn Co,* 200 Mich App 62, 65; 503 NW2d 695 (1993); January 20, 1982 order in Case No. U-6923; and November 29, 1993 order in Case No. U-10335. The Commission further notes that several protective orders have been recently issued that allow parties to retain confidential information from one proceeding for possible use in a subsequent proceeding.[8] In this case, the ALJ crafted a narrower order that only allows the information to be retained for a limited time period. The protective order tracks the language of previous protective

[8] *See,* April 21, 2014 order in Case No. U-17319; February 18, 2015 order in Case No. U-17680; April 10, 2015 order in Case No. U-17767; October 23, 2015 order in Case No. U-17792; April 4, 2016 order in Case No. U-17918; September 9, 2016 order in Case No. U-17678-R; September 2, 2016 order in Case No. U-18090; and December 20, 2016 order in Case No. U-17680-R.

orders, and the use of any confidential information obtained in this proceeding would require another protective order if used in another proceeding. Thus, the Commission does not find an abuse of discretion in the ALJ's ruling.

In addition, because the protective order is narrowly tailored to provide for limited retention of confidential materials by intervenors' counsel for a specific timeframe, the Commission determines that the terms of the protective order are reasonable and do not constitute a taking of personal property. The Commission finds that the cases cited by Consumers to support its taking argument are inapposite. As stated by MEC/NRDC/SC, the cases relate to property rights, however Consumers failed to cite any Michigan cases pertaining to discovery, or discovery issues involving regulated utilities. The only discovery-related case cited by Consumers is a Texas Court of Appeals case involving a discovery request in a personal injury case where plaintiffs sought to pierce the corporate veil. Agreeing with MEC/NRDC/SC, the Commission finds this case to be irrelevant.

The Commission also rejects Consumers' narrow interpretation of Section 74 of the State Administrative Procedures Act, 1969 PA 306. The language of MCL 24.274(1) specifically states that the Commission may "adopt rules providing for discovery and depositions to the extent and in the manner appropriate to its *proceedings*." (Emphasis added.) Contrary to the company's claim, the Commission finds that its authority to adopt discovery rules is not confined to a single proceeding.

The Commission also finds MEC/NRDC/SC's policy arguments persuasive. The Commission finds value in this type of protective order because it improves efficiency between related cases, and helps to reduce the number of discovery requests, discovery responses, and contested hearings.

This is especially important in light of the tightened timeframe set forth in Act 341, which shortens rate cases from 12 months to 10 months.

Based on the foregoing, the Commission finds that Consumers' appeal should be denied.

THEREFORE, IT IS ORDERED that:

A. Based on this order's findings adopting a 2016-2017 test year, a jurisdictional rate base of $10,159,167,000, an authorized rate of return on common equity of 10.10%, and an authorized required rate of return of 5.94%, Consumers Energy Company is authorized to implement rates that increase its annual electric revenues by $113,277,000 on a jurisdictional basis over the rates approved on November 19, 2015, in Case No. U-17735.

B. Consumers Energy Company is authorized to implement the rates approved by this order on a service rendered basis for service provided on and after March 7, 2017, as summarized in Attachment A, and set forth in Attachment B. Within 30 days of February 28, 2017, Consumers Energy Company shall file tariff sheets substantially similar to those contained in Attachment B. When filing the tariffs consistent with those ordered, Consumers Energy Company shall also update the Contribution In Aid of Construction Allowance Schedule amounts on Tariff Sheet C-3.10, Section C1.4 to be consistent with the rates approved in this order. Due to the size of Attachment B, it is not physically attached to the original order contained in the official docket or paper copies of the order, but is electronically appended to this order, which is available on the Commission's website.

C. On or before May 31, 2017, Consumers Energy Company shall file an application for authority to conduct a self-implementation reconciliation proceeding as required under MCL 460.6a(1).

D. Consumers Energy Company shall submit a draft distribution investment and maintenance plan to the Commission Staff by August 1, 2017. Subsequently, the company shall meet with the Staff to discuss the framework for completing a final five-year distribution investment and maintenance plan to be submitted by January 31, 2018.

E. In its next general rate case, Consumers Energy Company shall provide a detailed benefit/cost analysis regarding the retirement of the D.E. Karn 1 and 2 and J.H. Campbell 1 and 2 units as set forth in this order.

F. In its next general rate case, Consumers Energy Company shall provide a study that compares power supply revenue from Rate GSG-2 customers to power supply costs caused by these customers, in order to determine whether current demand charges reflect the cost to serve standby customers.

G. In its next general rate case, Consumers Energy Company shall provide the requisite cost of service analysis if the company again proposes to use the interclass crossing-point adjustment.

H. Consumers Energy Company's accounting requests are approved as set forth in the order.

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, under MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General - Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Sally A. Talberg

Sally A. Talberg, Chairman

Norman J. Saari

Norman J. Saari, Commissioner

Rachael Eubanks

Rachael A. Eubanks, Commissioner

By its action of February 28, 2017.

Kavita Kale, Executive Secretary

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule

Total Revenues

Line No.	Description	(a) Sales	(b) Present Revenue	(c) Proposed Revenue	(d) Difference Revenue	(e) Difference Percent
		MWh	$000	$000	$000	%
	Bundled Service					
	Residential Class					
1	Residential Service RS	12,290,194	$ 1,852,801	$ 1,902,189	$ 49,388	2.7
2	Residential Time-of-Day RT	52,266	6,953	6,965	13	0.2
3	Residential Electric Vehicle REV	8,802	1,065	1,265	200	18.8
4	Res. Dynamic Price RSDP	-	-	-	-	NA
5	Res. Dynamic Price Rebate RSDPR	-	-	-	-	NA
6	Total Residential Class	12,351,262	1,860,819	1,910,420	49,600	2.7
	Secondary Class					
7	Secondary Energy-only GS	3,622,389	540,036	537,055	(2,982)	(0.6)
8	Sec. Energy Dynamic Price GSDP	-	-	-	-	NA
9	Secondary Demand GSD	3,872,534	485,436	487,107	1,671	0.3
10	Secondary Energy-only GS TOU	-	-	-	-	NA
11	Total Secondary Class	7,494,923	1,025,472	1,024,161	(1,311)	(0.1)
	Primary Class					
12	Primary Energy-only GP	1,441,467	154,469	164,026	9,558	6.2
13	Primary Demand GPD	11,337,619	903,165	951,928	48,763	5.4
14	Primary Energy Intensive Rate EIP	369,885	22,486	22,810	325	1.4
15	Primary Time of Use Pilot GPTU	245,434	20,452	22,836	2,384	11.7
16	Total Primary Class	13,394,405	1,100,571	1,161,601	61,030	5.5
	Lighting & Unmetered Class					
17	Metered Lighting Service GML	19,959	2,173	2,184	11	0.5
18	Unmetered Lighting Service GUL	126,290	27,608	29,947	2,340	8.5
19	Unmetered Exp. Lighting GU-XL	95	19	24	5	26.7
20	Unmetered Service GU	86,073	7,483	7,689	207	2.8
21	Total Lighting & Unmetered Class	232,417	37,282	39,844	2,563	6.9
	Self-generation Class					
22	Small Self-generation GSG-1	-	-	-	-	NA
23	Large Self-generation GSG-2	55,031	4,768	2,534	(2,234)	(46.8)
24	Total Self-Generation Class	55,031	4,768	2,534	(2,234)	(46.8)
25	Total Bundled Service	33,528,039	$ 4,028,913	$ 4,138,561	$ 109,648	2.7
	ROA Service					
	Residential Class					
26	Residential Service RS	-	$ -	$ -	$ -	NA
27	Residential Time-of-Day RT	-	-	-	-	NA
28	Total Residential Class	-	-	-	-	NA
	Secondary Class					
29	Secondary Energy-only GS	26,117	1,115	1,119	4	0.3
30	Secondary Demand GSD	224,954	7,285	7,339	54	0.7
31	Total Secondary Class	251,071	8,401	8,458	58	0.7
	Primary Class					
32	Primary Energy-only GP	66,525	1,120	1,255	135	12.0
33	Primary Demand GPD	3,938,798	20,502	23,960	3,458	16.9
34	Total Primary Class	4,005,323	21,622	25,215	3,593	16.6
35	Total ROA Service	4,256,394	$ 30,023	$ 33,673	$ 3,651	12.2
36	Total Bundled and ROA Service	37,784,432	$ 4,058,936	$ 4,172,234	$ 113,299	2.8

Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule

Power Supply Revenues

Line No.	Description	(a) Sales	(b) Present Revenue	(c) Proposed Revenue	(d) Difference Revenue	(e) Difference Percent
		MWh	$000	$000	$000	%
	Bundled Service					
	Residential Class					
1	Residential Service RS	12,290,194	$ 1,185,077	$ 1,210,118	$ 25,041	2.1
2	Residential Time-of-Day RT	52,266	4,457	4,366	(91)	(2.0)
3	Residential Electric Vehicle REV	8,802	603	786	183	30.3
4	Res. Dynamic Price RSDP	-	-	-	-	NA
5	Res. Dynamic Price Rebate RSDPR	-	-	-	-	NA
6	Total Residential Class	12,351,262	1,190,138	1,215,271	25,133	2.1
	Secondary Class					
7	Secondary Energy-only GS	3,622,389	341,656	338,573	(3,082)	(0.9)
8	Sec. Energy Dynamic Price GSDP	-	-	-	-	NA
9	Secondary Demand GSD	3,872,534	350,530	351,420	890	0.3
10	Sec. Demand Dynamic Price GSDDP	-	-	-	-	NA
11	Total Secondary Class	7,494,923	692,186	689,994	(2,192)	(0.3)
	Primary Class					
12	Primary Energy-only GP	1,441,467	129,111	135,146	6,035	4.7
13	Primary Demand GPD	11,337,619	831,165	861,318	30,153	3.6
14	Primary Energy Intensive Rate EIP	369,885	20,988	20,619	(370)	(1.8)
15	Primary Time of Use Pilot GPTU	245,434	17,883	19,693	1,810	10.1
16	Total Primary Class	13,394,405	999,148	1,036,776	37,629	3.8
	Lighting & Unmetered Class					
17	Metered Lighting Service GML	19,959	1,065	1,047	(18)	(1.7)
18	Unmetered Lighting Service GUL	126,385	6,681	6,508	(173)	(2.6)
19	Unmetered Exp. Lighting GU-XL	95	5	5	(0)	(0.3)
20	Unmetered Service GU	86,073	6,237	6,390	153	2.5
21	Total Lighting & Unmetered Class	232,512	13,988	13,950	(38)	(0.3)
	Self-generation Class					
22	Small Self-generation GSG-1	-	-	-	-	NA
23	Large Self-generation GSG-2	55,031	2,698	-	(2,698)	(100.0)
24	Total Self-Generation Class	55,031	2,698	-	(2,698)	(100.0)
25	Total Bundled Service	33,528,134	$ 2,898,158	$ 2,955,990	$ 57,833	2.0
	ROA Service					
	Residential Class					
26	Residential Service RS	-	$ -	$ -	$ -	NA
27	Residential Time-of-Day RT	-	-	-	-	NA
28	Total Residential Class	-	-	-	-	NA
	Secondary Class					
29	Secondary Energy-only GS	26,117	-	-	-	NA
30	Secondary Demand GSD	224,954	-	-	-	NA
31	Total Secondary Class	251,071	-	-	-	NA
	Primary Class					
32	Primary Energy-only GP	66,525	-	-	-	NA
33	Primary Demand GPD	3,938,798	-	-	-	NA
34	Total Primary Class	4,005,323	-	-	-	NA
35	Total ROA Service	4,256,394	$ -	$ -	$ -	NA
36	Total Bundled and ROA Service	37,784,527	$ 2,898,158	$ 2,955,990	$ 57,833	2.0

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-17990
ATTACHMENT A

Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule

Delivery Revenues

Line No.	Description	(a) Sales MWh	(b) Present Revenue $000	(c) Proposed Revenue $000	(d) Difference Revenue $000	(e) Difference Percent %
	Bundled Service					
	Residential Class					
1	Residential Service RS	12,290,194	$ 667,724	$ 692,071	$ 24,347	3.6
2	Residential Time-of-Day RT	52,266	2,495	2,599	104	4.1
3	Residential Electric Vehicle REV	8,802	462	479	17	3.8
4	Res. Dynamic Price RSDP	-	-	-	-	NA
5	Res. Dynamic Price Rebate RSDPR	-	-	-	-	NA
6	Total Residential Class	12,351,262	$ 670,681	695,149	24,468	3.6
	Secondary Class					
7	Secondary Energy-only GS	3,622,389	198,381	198,481	101	0.1
8	Sec. Energy Dynamic Price GSDP	-	-	-	-	NA
9	Secondary Demand GSD	3,872,534	134,906	135,687	781	0.6
10	Sec. Demand Dynamic Price GSDDP	-	-	-	-	NA
11	Total Secondary Class	7,494,923	333,286	334,168	881	0.3
	Primary Class					
12	Primary Energy-only GP	1,441,467	25,358	28,880	3,523	13.9
13	Primary Demand GPD	11,337,619	71,999	90,610	18,610	25.8
14	Primary Energy Intensive Rate EIP	369,885	1,497	2,192	694	46.4
15	Primary Time of Use Pilot GPTU	245,434	2,569	3,143	574	22.3
16	Total Primary Class	13,394,405	101,424	124,825	23,401	23.1
	Lighting & Unmetered Class					
17	Metered Lighting Service GML	19,959	1,108	1,137	29	2.6
18	Unmetered Lighting Service GUL	126,290	20,927	23,439	2,513	12.0
19	Unmetered Exp. Lighting GU-XL	95	14	19	5	36.5
20	Unmetered Service GU	86,073	1,246	1,299	54	4.3
21	Total Lighting & Unmetered Class	232,417	23,294	25,895	2,600	11.2
	Self-generation Class					
22	Small Self-generation GSG-1	-	-	-	-	NA
23	Large Self-generation GSG-2	55,031	2,070	2,534	465	22.5
24	Total Self-Generation Class	55,031	2,070	2,534	465	22.5
25	Total Bundled Service	33,528,039	$ 1,130,755	$ 1,182,570	$ 51,815	4.6
	ROA Service					
	Residential Class					
26	Residential Service RS	-	$ -	$ -	$ -	NA
27	Residential Time-of-Day RT	-	-	-	-	NA
28	Total Residential Class	-	-	-	-	NA
	Secondary Class					
29	Secondary Energy-only GS	26,117	1,115	1,119	4	0.3
30	Secondary Demand GSD	224,954	7,285	7,339	54	0.7
31	Total Secondary Class	251,071	8,401	8,458	58	0.7
	Primary Class					
32	Primary Energy-only GP	66,525	1,120	1,255	135	12.0
33	Primary Demand GPD	3,938,798	20,502	23,960	3,458	16.9
34	Total Primary Class	4,005,323	21,622	25,215	3,593	16.6
35	Total ROA Service	4,256,394	$ 30,023	$ 33,673	$ 3,651	12.2
36	Total Bundled and ROA Service	37,784,432	$ 1,160,778	$ 1,216,244	$ 55,466	4.8

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(Continued From Sheet No. A-2.00)

SECTION C
COMPANY RULES AND REGULATIONS

(Continued on Sheet No. A-4.00)

INDEX

(Continued From Sheet No. A-4.00)

SECTION D
RATE SCHEDULES (Contd)

(Continued on Sheet No. A-6.00)

(Continued From Sheet No. C-4.00)

C1. CHARACTERISTICS OF SERVICE (Contd)

C1.6 General Provisions of Service (Contd)

A. Service Requirements (Contd)

The customer may have to provide a deposit and/or contribution if the service the customer requires cannot be provided from available distribution lines. The extension policy is stated in Rule C6., Distribution Systems, Line Extensions and Service Connections.

The customer may be required to provide, at no expense to the Company, a dedicated telecommunication line(s) as required for metering purposes, located within ten feet of the meter involved.

B. Parallel Operation Requirements

The Company shall not be required to operate in parallel with a customer's or operator's generating facilities when, in the opinion of the Company, such parallel operation may create a hazard, disturb, impair or interfere with communication circuits or with the Company's service to other customers. The Company may agree to parallel operation when the customer or operator provides adequate controlling and protective equipment necessitated by the presence of a source of power on the customer's or operator's premises and has sufficient trained personnel to perform the necessary operations. Such equipment and its installation shall be in accordance with the Generator Interconnection Requirements as approved by the Commission. It may further require the customer or operator to pay the cost of and maintain private telephone connections with the offices of the Company's Load Dispatcher, for the purpose of assuring continuity of service to other customers.

The customer or operator shall be responsible for furnishing, installing and maintaining, at the customer's or operator's expense, all necessary controlling and protective equipment for connecting the generating facility to the Company's electric system to protect the customer's or operator's equipment and service as well as the equipment and service of the Company from injury or interruptions which might be caused by a flow of current from the Company's lines to the customer's or operator's connections or from a flow of current from the customer's or operator's generating equipment to the Company's lines. The customer or operator shall assume any loss, liability or damage caused by a malfunction or lack of such equipment.

C2. CONTROLLED SERVICE (SEE SECTION C3.)

C3. EMERGENCY ELECTRICAL PROCEDURES

C3.1 General

Emergency Electrical Procedures may be necessary if there is a ***near-term*** shortage in the electrical energy supply to meet the demands of customers. ***For the purpose of this procedure, an Emergency Electrical Event may be i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of any electric system or the safety of persons or property; (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of Emergency Electrical Procedures as defined in this tariff. Conditions during an emergency event may escalate such that procedural steps are not followed in orderly succession.***

Consumers Energy is a member of a Regional Transmission Organization (RTO) which therefore dictates that during any Emergency Electrical Event, Consumers Energy will coordinate procedural steps with the RTO and with the applicable transmission operator. For longer-term forecasts of resource adequacy, the RTO works with Consumers Energy to ensure an effective and efficient resource adequacy construct with appropriate consideration of all eligible internal and external resources and resource types and recognition of legal/regulatory authorities and responsibilities.

The Company shall promptly advise the Commission of the nature, time and duration of implemented emergency procedures which ***could result in widespread disruption of service*** to customers. The Commission may order the implementation of additional procedures or the termination of the procedures previously employed when circumstances so require.

(Continued on Sheet No. C-6.00)

(Continued From Sheet No. C-5.00)

Sheet reserved for future use

(Continued on Sheet No. C-7.00)

(Continued From Sheet No. C-6.00)

C3. EMERGENCY ELECTRICAL PROCEDURES (Contd)

C3.2 *Generation* Capacity Shortages

A. Sudden or Unanticipated ***Frequency Event***

In the event of a major power system disturbance which results in an area being seriously deficient in generation, this procedure sheds load to restore a load-generation balance.

In the event of a sudden decline of the frequency on the system or a sudden breakup which isolates all or parts of the Company's electric system from other electric systems with which it is interconnected and which results in the area so isolated being deficient in electric generation, with consequent rapid decline in frequency***,-a***utomatic load shedding will take place ***per North American Electric Reliability Corporation (NERC) Reliability Standards***. ***Five percent (5%) of the system load will be shed automatically at each frequency step of 59.5, 59.3, 59.1, 58.9, and 58.7 Hertz as set forth in East Central Area Reliability Council (ECAR) Document No. 3.*** Service so interrupted shall be to certain substations and lines serving customers throughout the Company's service area. Such interruptions shall be, where practicable, for short periods of time. ***Consumers Energy will comply with Reliability Directives from the applicable transmission operator and Balancing Authority, as defined in the NERC glossary of terms, to restore the system as frequency is recovered.***

(Continued on Sheet No. C-8.00)

(Continued From Sheet No. C-7.00)

C3. EMERGENCY ELECTRICAL PROCEDURES (Contd)

C3.2 *Generation* Capacity Shortages (Contd)

B. ***Actual or Forecasted Generation*** Capacity Shortages

In the event ***the RTO determines that near-term*** conditions ***are such that maximum generation capacity is within 1% of forecasted peak load, as published daily by the RTO, plus operating reserves, as defined in the NERC glossary of terms, an Emergency Alert Level is declared. For all emergency levels, the Company will advise the MPSC staff by telephone. The Alert Level steps are:***

(1) Generation assets will cancel maintenance that could jeopardize capability and expedite returning equipment to service if it increases capability.
(2) Hydro facilities will coordinate schedules to ensure maximum output during the alert period.
(3) Operators will dispatch to sites that will need operator assistance to make equipment available.
(4) Non-utility generators and independent power producers will be polled for additional energy.
(5) Tariff Interruptible loads will be advised of system conditions.

In the event the ***RTO determined that forecasted energy reserves are less than required, actual operating reserves are less than required, or transmission constraints may be projected to limit energy transfer, the RTO will declare an Emergency Warning Level. For all declared emergency levels, the Company will advise the MPSC staff by telephone. The Warning Level steps are:***

(1) The Company will ensure all steps of the Alert Level have been performed.
(2) Internal load reduction will be implemented.
(3) The Company will schedule any external to the RTO resources into the RTO area.
(4) Non-firm energy sales will be curtailed.

In the event that the RTO determines that real-time energy demand and operating reserve requirements cannot be met, an Event Level emergency is declared. For all declared emergency levels, the Company will advise the MPSC staff by telephone. The Event Level steps are:

(1) Ensure all steps of the Alert and Warning Level have been performed.
(2) Start off-line resources as needed.
(3) Direct that public appeal for load reduction be issued.
(4) Implement Load Modifying Resources (LMR) such as tariff interruptible loads.
(5) Poll industrial customers for voluntary load reduction and instruct those volunteers to implement load reduction.
(6) Request that government environmental restrictions are lifted on generation suffering such reductions.
(7) Direct shedding of firm load as directed by the RTO.

Emergency Event Termination is determined by the RTO. Upon termination, the Company will work backward through the implemented steps and ensure all notifications to generation sites, facilities, industrial customers, tariff interruptible customers, and the MPSC have been made.

(Continued on Sheet No. C-9.00)

Sheets reserved for future use

(Continued From Sheet No. C-12.00)

C3. EMERGENCY ELECTRICAL PROCEDURES (Contd)

C3.3 Long-Term Capacity or Fuel Shortages (Contd)

A. Fuel Shortages

The Company shall notify the MPSC Staff of the fuel supply shortage if such shortfall is expected to impact customer service.

A Coal Fuel Shortage occurs at a generation facility when available supplies and deliveries are forecasted to fall below 15 days.

A Fuel Shortage of natural gas occurs at a generation facility when that facility is physically unable to receive gas delivery on a daily basis.

In the event of ***a*** fuel shortage ***at a generation facility***, the Company ***shall take one or more of the following actions:***

(1) Attempt to find alternate supplies or transportation of fuel.
(2) Optimize deliveries of fuel to all generation facilities to free up supply.
(3) Reduce dispatch of the affected generator(s).
(4) Purchase capacity or energy to replace the facility.
(5) Enter into load management agreements with large industrial customers.
(6) Optimize all other generating facilities to free up supply.

(Continued on Sheet No. C-14.00)

Sheets reserved for future use

(Continued From Sheet No. C-15.00)

C3.4 **Short-Term Capacity Shortages Outside of the Company's Service Area**

Firm service to customers in the Company's service area may be interrupted at the direction of the ***RTO*** in order to provide service to suppliers of electric energy outside of the Company's service area.

(Continued on Sheet No. C-17.00)

Sheet reserved for future use

(Continued From Sheet No. C-18.00)

C4. APPLICATION OF RATES

C4.1 Classes of Service

The rates specified in this Electric Rate Book are predicated upon the delivery of each class of service to a single metering point for the total requirements of each separate premises of the customer, unless otherwise provided for in the Company's Electric Rate Book.

Service to different delivery points and/or different classes of service on the same premises shall be separately metered and separately billed. In no case shall service be shared with another premises or transmitted off the premises to which it is delivered.

C4.2 Choice of Rates

A customer may be eligible to have service billed on one of several rates or provisions of a rate. Upon request, the Company shall advise the customer in the selection of the rate or rate provision which is most likely to give the customer the lowest cost of service based on the information provided to the Company. The selection of the rate or provision of a rate is the responsibility of the customer. Because of varying customer usage patterns and other reasons beyond its reasonable knowledge or control, the Company does not guarantee that the most economic applicable rate will be applied.

(Continued on Sheet No. C-20.00)

(Continued From Sheet No. C-23.00)

C4. APPLICATION OF RATES (Contd)

C4.3 Application of Residential Usage and Non-Residential Usage (Contd)

D. Rate Application for Seasonal Condominium Campgrounds (Contd)

(5) The customer must notify individuals and/or co-owners utilizing the customer's property that the customer's facilities may not be able to be located by Miss Dig.
(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.

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.

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 Demand Rate GSD, General Service Primary Rate GP, or General Service Primary Demand Rate GPD. 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 RS 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, Residential Service Time-of-Day Secondary Rate RT 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:

$***0.147744*** per kWh for all kWh during the months of June-September
$***0.145694*** 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-25.00)

(Continued From Sheet No. C-24.00)

C4. APPLICATION OF RATES (Contd)

C4.4 Resale (Contd)

The service contract shall also provide that the reselling customer shall be responsible for the testing of each ultimate user's meter at least once every 3 years. The accuracy of such meters shall be maintained within the limits as prescribed in Rule B1., Technical Standards for Electric Service. Meters shall be tested only by outside testing services or laboratories approved by the Company.

A record of each meter, including testing results, shall be kept by the reselling customer during use of the meter and for an additional period of one year thereafter. When requested, the reselling customer shall submit certified copies of the meter test results and meter records to the Company.

The reselling customer shall supply each ultimate user with an electric system adequate to meet the needs of the ultimate user with respect to the nature of service, voltage level and other conditions of service. The reselling customer shall render a bill once during each billing month to each of the customer's tenants in accordance with approved Rate Schedules of the Company. Every bill rendered by the reselling customer shall specify the following information: the rate categories and provisions; the due date; the beginning and ending meter readings of the billing period and dates thereof; the difference between the meter readings; the Power Supply Cost Recovery Factor; if applicable; the subtotal of the bill before taxes; amount of sales tax; other local taxes where applicable; any previous balance; the amount due for delivery service and/or power supply service, as applicable; the amount due for other authorized charges; and the total amount due. The due date of the customer's bill shall be 21 days from the date of rendition.

If the reselling customer fails to meet the obligations of this rule, the Company shall notify the Commission. If, after review with the reselling customer, the problem is not resolved, the Company shall assess a penalty in the amount of ***5%*** of the resale customer's bill before taxes per month until the problem is resolved. ***The reselling customer is not permitted to pass the resale penalty cost on to its ultimate customer(s).*** If the problem is not resolved after three months, the Company shall shut off electric service until the problem is resolved.
The Company shall not incur any liability as the result of this shutoff of electric service.

The renting of premises with the cost of electric service included in the rental as an incident of tenancy is not considered to be a resale of such service.

Neither the resale of electric services provided by Consumers Energy nor the sale of self-generation at publicly available electric vehicle charging stations is subject to Commission regulation and no restrictions are imposed on the rate charged or rate structure to the ultimate motor vehicle customer, as those sales are being made into the competitive motor fuels market.

C4.5 Mobile Home Park - Individually Served

For purposes of this rule, the definition of a mobile home park is a parcel or tract of land upon which three or more mobile homes are located on a continuous nonrecreational basis.

Service to separately metered mobile homes shall be billed on the appropriate Residential Service Rate under the following conditions:

Service to all new mobile home parks and expanded service to existing mobile home parks receiving electrical service shall be provided through individual tenant metering.

The mobile home park shall be of a permanent nature with improved streets and with individual water and sewer connections to each lot. Ordinarily, electric service to a mobile home shall be in the name of the occupant. However, service to lots designated for occasional or short-term occupancy shall be in the name of the owner of the park or his/her authorized representative.

(Continued on Sheet No. C-26.00)

(Continued From Sheet No. C-30.00)

C5. CUSTOMER RESPONSIBILITIES (Contd)

C5.2 Bills and Payments (Contd)

J. Energy Theft, Stolen Meter and Switched Meter

In cases where metered or unmetered energy theft, stolen meter or switched meter by someone other than a Company representative are involved, refunds and backbillings are for the determined duration of the period. Where the duration cannot be reasonably established or estimated, the Company will adjust the billing for the past three years on the basis of actual monthly consumption determined from the most recent 36 months of consumption data.

Metered or unmetered energy theft includes but is not limited to tampering, unauthorized use, diversion and interference. For purposes of this rule, a stolen meter is classified as any meter not specifically assigned to that service location by the Company. For purposes of this rule, a switched meter is classified as a meter intentionally assigned incorrectly to a customer resulting in the customer being billed for another customer's consumption.

The Company reserves the right to recover all unbilled service revenue and reasonable actual costs associated with the theft of energy, stolen meters or switched meters. Therefore, the customer or other user who benefits from the unauthorized or fraudulent use is responsible for payment of the reasonable actual cost of the service used during the period such fraudulent or unauthorized use or tampering occurred, or is reasonably assumed to have occurred, and is responsible for the reasonable actual cost of the tampering investigation and any associated damages, with the exception that all costs be recovered in cases involving criminal prosecution. The customer who did not intentionally steal a meter, switch a meter or who did not intentionally become involved in energy theft shall pay for energy usage according to Section H of this rule.

The owner of the multiple metered building shall be responsible for accurately tracing all lines and for tagging such lines with Company-provided tags to assure individual units are properly metered. The Company will not set the meters until the lines are identified. The owner of the multiple metered building could be held responsible for any underrecovery of revenues resulting from improperly tagged meters. Any future expense of tracing lines due to instances of switched meters related to errors in tracing and tagging of such lines shall be the responsibility of the current owner of the multiple metered building.

C5.3 Restoration of Service

Restoration charges and meter relocation charges shall be made by the Company to partially cover the cost of shutting off, terminating and restoring service.

Where service has been shut off for reasons as outlined in Rule C1.3, Use of Service, a restoration charge of ***$11*** shall be collected from the customer whose service was disconnected at the customer's meter. If service was disconnected at the point of contact with the Company's distribution system, a charge of $80 shall be collected from the customer whose service was shut off.

Where service has been shut off for reasons as outlined in Rule C1.3, Use of Service, a meter relocation charge, if applicable, and assessed in accordance with Rule B2., Consumer Standards and Billing Practices for Electric and Gas Residential Service, R 460.116, Meter Accuracy, Meter Errors, Meter Relocations, and R 460.144, Restoration of Service, shall be collected from the customer whose service was shut off. The Company shall charge the customer for relocating the meter, based on the Company's current cost.

(Continued on Sheet No. C-32.00)

(Continued From Sheet No. C-31.00)

C5. CUSTOMER RESPONSIBILITIES (Contd)

C5.3 Restoration of Service (Contd)

The restoration charge and meter relocation charge, if applicable, shall be billed to the customer and shall be paid before service is restored.

An On-Premises Site Visit Charge of $15.00 shall be assessed to the customer if a Company employee is sent to the premises to either serve the customer with a shut-off notification or to shut off service, unless the customer presents evidence that reasonably indicates the claim has been satisfied or is currently in dispute. The charge shall be applied to the customer account. The Company shall not assess this fee twice on the same notice for shutoff.

In case of shutoff of service, the Company shall restore service only after any metering changes, where deemed necessary by the Company, have been made by the Company and after the customer has paid for any unmetered energy used, paid for any damage to Company property, paid the restoration charge and meter relocation charge, installed any necessary devices to protect the Company's facilities and paid all charges as provided in the Company's Electric Rate Book.

A customer who orders a termination and a restoration of service at the same premises within a 12-month period shall be liable for a "turnon" charge of ***$11***.

C5.4 Shutoff Protection Plan for Residential Customers

A. Eligibility

Eligible low-income customers and senior citizen customers may choose to participate in the Shutoff Protection Plan (SPP) in lieu of the applicable Winter Protection Plan as described in Rule B2., Consumer Standards and Billing Practices for Electric and Gas Residential Service, R 460.148, Winter Protection Plan for Low-income Customers, or R 460.149, Winter Protection Plan for Senior Citizens. For purposes of this Company rule, an eligible low-income customer means a utility customer who has not had more than one default condition on the SPP in the last twelve months and whose household income does not exceed 200% of the federal poverty guidelines as published by the United States Department of Health and Human Services or who receives supplemental security income or low-income assistance through the Department of Human Services or successor agency, food stamps, or Medicaid. In addition, an eligible senior citizen customer means a utility customer who has not had more than one default condition on the SPP in the last twelve months, is 65 years of age or older, and advises the utility of his or her eligibility. An eligible customer enrolled in the SPP shall be referred to as an SPP Customer. Customers who are actively participating in the Consumers Affordable Resource for Energy (CARE) Pilot or have participated in the CARE Pilot during the concurrent heating season are not eligible to participate in SPP until the beginning of the next heating season.

(Continued on Sheet No. C-32.10)

(Continued From Sheet No. C-32.30)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd)

C6.1 Overhead Extension Policy (Contd)

A. Residential Customers (Contd)

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 the first year's estimated 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.***

B. General Service Customers

The Company shall construct single-phase and three-phase distribution line extensions, at its own cost when the cost of such extension does not exceed three times the estimated annual revenue from the customer(s) to be immediately served.

Extensions in excess of the above free allowance shall require a deposit from the customer, in an amount equal to the estimated construction costs in excess of the free allowance.

(1) Original Customers

At the end of the first complete 12-month period beginning the month following the date the line extension is completed, the Company shall refund to the depositor three times the amount that actual revenue exceeds the original revenue estimate. If the actual revenue exceeds the estimated revenue, the actual revenue then becomes the base upon which future refund calculations are to be made during the remainder of the five-year refund period.

(2) Additional Connected Customers

The Company shall refund $500 for each residential customer and/or the first year's estimated revenue for each General Service customer who connects directly to the line for which a deposit was required. 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 be made until the original customer(s) or equivalent is actually connected to the extension. 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.

C. General

(1) Refundable deposits made with the Company under this rule shall be subject to refund without interest, for a five-year period which begins the month after the line extension is completed. The Company shall have no further obligation to refund any remaining portion of line extension deposits.

(2) Each extension shall be a separate, distinct unit and any further extension therefrom shall have no effect upon the agreements under which existing extensions were constructed.

(3) Refunds cannot exceed the refundable portion of the deposit.

(4) Estimated construction costs shall exclude services and meters.

(5) The applicant shall furnish, without cost to the Company, all necessary rights-of-way and tree trimming permits, in a form satisfactory to the Company. If the applicant is unable to secure rights-of-way and permits, in a form satisfactory to the Company, the Company shall extend its distribution system along an alternate route selected by the Company, and shall require the applicant to pay all additional costs incurred.

(Continued on Sheet No. C-34.00)

(Continued From Sheet No. C-41.00)

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 1.0792 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-4.00.

Should the Company apply lesser factors than those shown on Sheet No. D-4.00, 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-4.00.

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-43.00)

(Continued from Sheet No. C-48.60)

C10. RENEWABLE ENERGY PLAN (REP) (Contd)

C10.5 Pilot Solar Program

The purpose of this rule is to develop and test programs to enable the development of Michigan's renewable energy resources. The Pilot Solar Program (Solar Program) is a voluntary program intended to further the deployment of solar energy in Michigan and meet customer demand. The Solar Program, offered for a period of three years beginning 90 days following Commission approval of this tariff, will consist of up to 10 MW of large scale solar facilities. The Company will own and maintain all facilities under this pilot and/or contract with Independent Power Producers for the solar energy output of facilities located within Consumers Energy's electric distribution service area.

Eligible customers will have an opportunity to subscribe to the Solar Program. A subscription is equal to 0.5 kW of solar energy. Customers may subscribe to more than one subscription; however, a customer's total subscriptions shall not exceed the customer's Annual Net Usage. A subscribed customer will receive a Solar Energy Credit for the subscription's percentage of the solar energy generated in the Solar Program. This Solar Energy Credit includes the energy and capacity value of the program production as defined herein, and avoided line losses. The Company will retire the Renewable Energy Credits (REC), as defined in Public Act 295 of 2008 and in compliance with MCL 460.1011. The customer can opt to have the Company sell the REC, rather than retire it, and then the value of the REC will be included in the Solar Energy Credit.

A. Definitions

Annual Net Usage - the average annual kWh usage or the annual Imputed Customer Usage in kWhs if enrolled in Net Metering.

Long Term Program Capacity Value - the product of the Zonal Resource Credits for the facilities, as determined by Mid-Continent Independent System Operator (MISO), and 75% of the applicable MISO published Cost of New Entry for the resource zone in the lower peninsula of Michigan, adjusted annually.

Long Term Program Energy Value - the kWh production of the Solar Program at each hourly interval, multiplied by the hourly day ahead Locational Marginal Price (LMP) at the CONS.CETR pricing node, adjusted for applicable line losses.

Short Term Program Energy and Capacity Value - the monthly kWh production of the Solar Program multiplied by the fixed rate of $0.075/kWh.

Solar Energy Credit - the monthly bill credit provided to the enrolled customer based on enrollment level, program solar energy production and the value of the energy credit and capacity credit described below and, if chosen by the customer, the value of the REC.

Subscription Payment - a payment to participate in the Solar Program, equal to the cost of 0.5 kW of solar capacity.

B. Customer Eligibility

Subject to any restrictions, the Solar Program is available to any Full Service customer served on Rate RS, RT, GS, GSD, GP, GPD, ***EIP***, and GPTU. Customers will not be eligible for the Solar Program if they have received a shutoff notice within nine months preceding their application.

(Continued on Sheet No. C-48.64)

RATE CATEGORIES AND PROVISIONS

Description	Full Service	Retail Open Access
RESIDENTIAL SERVICE SECONDARY RATE RS		
Residential	1000	2000
Provisions		
Residential With Income Assistance (RIA) *	Applicable	Applicable
Residential With Senior Citizen (RSC) *	Applicable	Applicable
Peak Power Savers Program	1005	Not Applicable
Residential With Self-Generation (SG)**	1700	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
Non-Transmitting Meter Provision	Applicable	Applicable
RESIDENTIAL SERVICE DYNAMIC PROGRAM		
Residential Dynamic Pricing (RDP)	***1007***	***Not Applicable***
Residential Dynamic Pricing Rewards (RDPR)	***1008***	***Not Applicable***
Provisions		
Residential Dynamic Pricing With Income Assistance (RIA) *	***Applicable***	***Applicable***
Residential Dynamic Pricing With Senior Citizen (RSC)*	***Applicable***	***Applicable***
Residential Dynamic Pricing With Self-Generation (SG)	***1700***	***Not Applicable***
Green Generation Program	***Applicable***	***Not Applicable***
RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT		
Residential Time-of-Day	1010	2010
Provisions		
Residential Time-of-Day With Income Assistance (RIA) *	Applicable	Applicable
Residential Time-of-Day With Senior Citizen (RSC)*	Applicable	Applicable
Residential Time-of-Day With Self-Generation (SG)***	1705	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM		
Residential Electric Vehicle Service (REV-1)	1020	Not Applicable
Residential Electric Vehicle Service (REV-1) With Self-Generation (SG)***	1710	Not Applicable
Residential Electric Vehicle Service (REV-2)	1030	Not Applicable
Green Generation Program	Applicable	Not Applicable

* Provisions shall not be taken in conjunction with each other.
** Provisions shall not be taken in conjunction with the Direct Load Management Provision or the Net Metering Program.
***Provisions shall not be taken in conjunction with the Net Metering Program.

(Continued on Sheet No. D-6.10)

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-6.00)

Description	Full Service	Retail Open Access
GENERAL SERVICE SECONDARY RATE GS		
Commercial	1100	2100
Commercial-Temporary Construction Service	1999	Not Applicable
Industrial	1110	2110
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
Industrial With Educational Institution (GEI)	Applicable	Applicable
Commercial With Self-Generation (SG)**	1715	Not Applicable
Industrial With Self-Generation (SG)**	1720	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
Non-Transmitting Meter Provision	Applicable	Applicable
GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU		
Commercial	***1121***	***Not Applicable***
Industrial	***1122***	***Not Applicable***
Provisions		
Commercial With Educational Institution (GEI)	***Applicable***	***Applicable***
Industrial With Educational Institution (GEI)	***Applicable***	***Applicable***
Commercial With Self-Generation (SG)***	***1716***	***Not Applicable***
Industrial With Self-Generation (SG)***	***1721***	***Not Applicable***
Green Generation Program	***Applicable***	***Not Applicable***
GENERAL SERVICE SECONDARY DEMAND RATE GSD		
Commercial	1120	2120
Industrial	1130	2130
Commercial (100 kW Billing Demand Guarantee)	1140	2140
Industrial (100 kW Billing Demand Guarantee)	1150	2150
Provisions		
Commercial Resale	Applicable	Applicable
Commercial With Educational Institution (GEI)	Applicable	Applicable
Industrial With Educational Institution (GEI)	Applicable	Applicable
Commercial With Self-Generation (SG)**	1725	Not Applicable
Industrial With Self-Generation (SG)**	1730	Not Applicable
Commercial (100 kW Billing Demand Guarantee) With Self-Generation (SG)**	1735	Not Applicable
Industrial (100 kW Billing Demand Guarantee) With Self-Generation (SG)**	1740	Not Applicable
Green Generation Program	Applicable	Not Applicable
Non-Transmitting Meter Provision	Applicable	Applicable

*Provisions shall not be taken in conjunction with the DLM Provision, GEI Provision, or the Net Metering Program.
**Provisions shall not be taken in conjunction with Dynamic Pricing or the Net Metering Program.

(Continued on Sheet No. D-7.00)

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-6.10)

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
Green Generation Program	Applicable	Not Applicable
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
Green Generation Program	Applicable	Not 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 with Education Institution (GEI)	***Applicable***	***Applicable***
Industrial with Education Institution (GEI)	***Applicable***	***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
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE ENERGY INTENSIVE PRIMARY RATE EIP		
Industrial (Customer Voltage Level 1, 2, or 3)	1250	Not Applicable
Provisions		
Commercial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG)** *	***1775***	***Not Applicable***
Industrial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG)*	***1780***	***Not Applicable***
Green Generation Program	***Applicable***	***Not Applicable***

* Provisions shall not be taken in conjunction with the DLM provision, GEI provision, or the Net Metering Program.
** Provisions shall not be taken in conjunction with each other, with Dynamic Pricing or the Net Metering Program.
***Provisions shall not be taken in conjunction with the DLM provision or the Net Metering Program.

(Continued on Sheet No. D-7.10)

RESIDENTIAL SERVICE SECONDARY RATE RS

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, without the specific consent of the Company.

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:	$***0****.093884*	per kWh for the first 600 kWh per month during the billing months of June-September
	$***0.126757***	per kWh for all kWh over 600 kWh per month during the billing months of June-September
	$*0.093884*	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-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

System Access Charge:	$7.00	per customer per month
Distribution Charge:	$*0.047220*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-10.00)

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-9.00)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2, Consumer Standards and Billing Practices for Electric and Gas Residential Customers, R 460.102, Definitions. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Income Assistance Credit: $(7.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

(Continued on Sheet No. D-11.00)

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-10.00)

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 and Retail Open Access customers.**

Senior Citizen Credit: $(3.50) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.
All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.
Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.
Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

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). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

***Peak Power Savers Program*:**

A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary ***Peak Power Savers Program for load management of eligible*** electric central air conditioning, central heat pump, or other qualifying electric equipment. Customer eligibility to participate in this ***program*** is determined solely by the Company. The customer must be located within an area in which Advanced Metering Infrastructure (AMI) is deployed and ***have a*** fully operational ***AMI meter*** for purposes of this ***program***. The Company will accept a customer's central air conditioning, central heat pump, and other qualifying electric equipment under this ***program*** only if it has the capability to be controlled by the Company. Load Management of a customer's swimming pool pump is permitted under this ***program*** only if the customer is allowing Load Management of their air conditioner or heat pump unit. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. 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.

(Continued on Sheet No. D-11.10)

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-11.00)

Monthly Rate: (Contd)

***Peak Power Savers Program*: (Contd)**

The Company reserves the right to specify the term or duration of the ***program***. The participating customer may elect to terminate service for any reason by providing the Company with thirty days' notice prior to the customer's next billing cycle. 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.

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. 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 Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management 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 ***Peak Power Savers*** 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 Direct Load Management Pilot.

The monthly credit for the ***Peak Power Savers Program*** shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Power Savers Credit: $ ***(7.84)*** per ***customer per month***

(Continued on Sheet No. D-11.20)

Sheet reserved for future use

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-11.30)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., 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.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., 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.

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, 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 Gas Residential Service, R 460.122, Allowable Charges.

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

RESIDENTIAL DYNAMIC PRICING PROGRAM

Availability:

The Residential Dynamic Pricing Program is voluntary and available to Full Service residential customers who have, or are selected to have, the required metering equipment and infrastructure installed. Customer eligibility to participate in this program is determined solely by the Company. The Company will furnish, install, maintain and own the required equipment at the customers' premises at the Company's expense. At the sole discretion of the Company, customers may be allowed to furnish, install and maintain the equipment at the customer's expense. Equipment and installations must conform to the Company's specifications. By enrolling in the program, the customer agrees to provide an email address, to participate in surveys and understands that the metering data will be used for evaluation purposes.

The participating customer may elect to terminate service for any reason giving the Company thirty days' notice prior to the customer's next billing cycle. The customer's enrollment shall be terminated if the program ceases or for any reasons as provided for in Rule C1.3, Use of Service.

Deployment of the Residential Dynamic Pricing Program is at the sole discretion of the Company and is dependent upon installation of advanced metering infrastructure and supporting critical systems.

Customers participating in the Residential Dynamic Pricing Program shall not participate in any other Demand Response Program or Net Metering.

The program 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 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.

Rate Options:

Customers are able to manage electric costs by either reducing load during high cost pricing periods or shifting load from high cost pricing periods to lower cost pricing periods. Upon enrollment of the customer in the Residential Dynamic Pricing Pilot, the customer shall take service under one of the following rate options:

Option 1 – Residential Dynamic Pricing (RDP) – During a critical peak event, customers on Rate RDP will be charged the Critical Peak Event charge for all kWh consumed during the critical peak event.

Option 2 – Residential Dynamic Pricing Rewards (RDPR) – During a critical peak event, customers on Rate RDPR will be credited the Critical Peak Rebate for incremental energy reductions.

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.

Monthly Rate:
Option 1 – Residential Dynamic Pricing Rate RDP:

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	$/kWh	
Off-Peak – Summer	$0.077645	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak – Summer	$0.105776	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak – Summer	$0.143396	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak – Winter	$0.077645	per kWh for all Off-Peak kWh during the billing months of October-May
Mid-Peak – Winter	$0.096645	per kWh for all Mid-Peak kWh during the billing months of October-May
Critical Peak Event	$0.950000	per kWh during a critical peak event between June 1 and September 30

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-13.02)

RESIDENTIAL DYNAMIC PRICING PROGRAM

(Continued From Sheet No. D-13.00)

Monthly Rate: (Contd)

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	*$7.00*	*per customer per month*
Distribution Charge:	*$0.047220*	*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-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

Option 2 – Residential Dynamic Pricing Rewards Rate RDPR:

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	$/kWh	
Off-Peak – Summer	*$0.082808*	*per kWh for all Off-Peak kWh during the billing months of June-September*
Mid-Peak – Summer	*$0.112809*	*per kWh for all Mid-Peak kWh during the billing months of June-September*
On-Peak – Summer	*$0.152931*	*per kWh for all On-Peak kWh during the billing months of June-September*
Off-Peak – Winter	*$0.082808*	*per kWh for all Off-Peak kWh during the billing months of October-May*
Mid-Peak – Winter	*$0.103071*	*per kWh for all Mid-Peak kWh during the billing months of October-May*
Critical Peak Reward	*$(0.950000)*	*per kWh during a critical peak event between June 1 and September 30*

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	*$7.00*	*per customer per month*
Distribution Charge:	*$0.047220*	*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-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2, Consumer Standards and Billing Practices for Electric and Gas Residential Customers, R 460.102, Definitions. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Income Assistance Credit: $(7.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

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 and Retail Open Access customers.

Senior Citizen Credit: $(3.50) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

(Continued on Sheet No. D-13.04)

RESIDENTIAL DYNAMIC PRICING PROGRAM

(Continued From Sheet No. D-13.02)

Monthly Rate: (Contd)

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

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). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

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.

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 Gas Residential Service R 460.122, Allowable Charges.

(Continued on Sheet No. D-13.06)

RESIDENTIAL DYNAMIC PRICING PROGRAM

(Continued From Sheet No. D-13.04)

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*

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM

Availability:

The Experimental Residential Plug-In Electric Vehicle Charging Program is a voluntary pilot available to Full Service residential customers. Upon enrollment of the customer in the program, the customer may take service under one of the following options as applicable:

Option 1 - Residential Home and Plug-in Electric Vehicle Time-of-Day Rate (REV-1) – Level 1 or Level 2 Charging of an electric vehicle combined with household electric usage such as space conditioning, cooking, water heating, refrigeration, clothes drying, incineration or lighting based upon on-peak, mid-peak and off-peak periods and through a single meter.
Option 2 - Residential Plug-In Electric Vehicle Only Time-of-Day Rate (REV-2) – Level 2 Charging of the electric vehicle based upon on-peak, mid-peak and off-peak periods through a separate meter. Electric usage for the household will be billed under the RS or RT Rate Schedule.

"Level 1 Charging" is defined as voltage connection of 120 volts and a maximum load of 12 amperes or 1.4 kVA.

"Level 2 Charging" is defined as voltage connection of either 240 volts or 208 volts and a maximum load of 32 amperes or 7.7 kVA at 240 volts or 6.7 kVA at 208 volts.

"Electric Vehicle Supply Equipment (EVSE)" is defined as the conductors, including the ungrounded, grounded and equipment grounding conductors, the electric vehicle connectors, attachment plugs, and all other fittings, devices, power outlets, or apparatus installed specifically for the purpose of delivering energy from the premise wiring to the electric vehicle.

Vehicles shall be registered and operable on public highways in the State of Michigan to qualify for this rate. Low-speed electric vehicles including golf carts are not eligible to take service under this rate even if licensed to operate on public streets. The customer may be required to provide proof of registration of the electric vehicle to qualify for program.

The total connected load of the home including the electric vehicle charging shall not exceed 10 kW, without the specific consent of the Company.

Customers shall not back-feed or transmit stored energy from the electric vehicle's battery to the Company's distribution system.

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.

Monthly Rate: Option 1 – REV-1:

Power Supply Charges: These charges are applicable to Full Service customers.

Energy Charge:

	$/kWh	
Off-Peak – Summer	$***0.082808***	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak – Summer	$***0.112809***	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak – Summer	$***0.152931***	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak – Winter	$***0.082808***	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak – Winter	$***0.103071***	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-4.00.

(Continued on Sheet No. D-13.20)

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM

(Continued From Sheet No. D-13.10)

Monthly Rate (Contd)

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.
System Access Charge: $7.00 per customer per month

Distribution Charge: $***0.047220*** 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-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

General Terms:

These rates are subject to all general terms and conditions shown on Sheet No. D-1.00.

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

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). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstance.

(Continued on Sheet No. D-13.25)

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM

(Continued From Sheet No. D-13.20)

Monthly Rate (Contd)

Option 2 - REV-2:

Power Supply Charges: These charges are applicable to Full Service customers.

Energy Charge:

	$/kWh
Off-Peak – Summer	$***0.082808*** per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak – Summer	$***0.112809*** per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak – Summer	$***0.152931*** per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak – Winter	$***0.082808*** per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak – Winter	$***0.103071*** 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-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

Distribution Charge: $***0.047220*** for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10. The REP Surcharge shown on Sheet No. D-2.10 shall not apply.

General Terms:

These rates are subject to all general terms and conditions shown on Sheet No. D-1.00.

(Continued on Sheet No. D-13.30)

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM

(Continued From Sheet No. D-13.25)

Schedule of On-Peak 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:

(1)	Off-Peak Hours:	11:00 PM to 7:00 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:

(1)	Off-Peak Hours:	11:00 PM to 7:00 AM
(2)	On-Peak Hours:	7:00 AM to 11:00 PM

Minimum Charge:

REV-1 - ***T***he System Access Charge included in the rate, adjusted for ***qualified*** service provision credit ***and any applicable non-consumption based surcharges***.
REV-2 - ***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 Gas Residential Service, R 460.122, Allowable Charges.

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.

Term and Form of Contract:

Service under this rate shall not require a written contract, except for a customer who receives a contribution for purchase or installation of the EVSE, installation of the separately metered service from the Company, or who participates in the Green Generation Program. The Company reserves the right to specify the term of duration of the experimental rates. The participating customer may elect to terminate service for any reason giving the Company ten business days notice prior to the customer's next billing cycle. The customer's enrollment shall be terminated if the voluntary pilot ceases or for any reason as provided for in Rule C1.3, Use of Service.

RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT

Availability:

Subject to any restrictions, this rate is available to any residential customer desiring electric service who chooses to have their electric consumption metered based upon on-peak and off-peak periods. In addition, this rate is available to customers desiring electric service for electric vehicle battery charging where such service is in addition to all other household requirements. Battery charging service is limited to four-wheel vehicles licensed for operation on public streets and highways. 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, without the specific consent of the Company.

Service under this rate is limited to 10,000 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.

On-Peak – Summer	$***0.111706***	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak – Summer	$***0.075406***	per kWh for all Off-Peak kWh during the billing months of June-September
On-Peak – Winter	$***0.091696***	per kWh for all On-Peak kWh during the billing months of October-May
Off-Peak – Winter	$***0.079368***	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-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

System Access Charge:	$7.00	per customer per month
Distribution Charge:	$***0.047220***	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-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit ***by meeting*** the requirements under Rule B2, Consumer Standards and Billing Practices for Electric and Gas Residential Customers, R 460.102***, Definitions***. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Income Assistance Credit:	$(7.00)	per customer per month

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

(Continued on Sheet No. D-15.00)

RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT

(Continued From Sheet No. D-14.00)

Monthly Rate: (Contd)

Senior Citizen Service Provision (RSC):

When service is supplied to the Principle 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 and Retail Open Access Customers.

Senior Citizen Credit: $(3.50) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

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). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstance.

(Continued on Sheet No. D-16.00)

RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT

(Continued From Sheet No. D-15.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11, 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.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11, 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.

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 Gas Residential Service, R 460.122, Allowable Charges.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday***, including holidays when applicable***:

(1) On-Peak Hours: 11:00 AM to 7:00 PM
(2) Off-Peak Hours: 7:00 PM to 11:00 AM

Saturday and Sunday are Off-Peak.

Term and Form of Contract:

Service under this rate shall not require a written contract.

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:	$***0.093995***	per kWh for during the billing months of June-September
	$***0.091945***	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-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access (ROA) Customers.

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$***0.042154***	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

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-19.00)

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-18.00)

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: $ ***(0.000751)*** 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.

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

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). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

(Continued on Sheet No. D-19.10)

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-19.00)

Sheet reserved for future use

(Continued on Sheet No. D-20.00)

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-19.10)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11, 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.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11, Net Metering Program.

(Continued on Sheet No. D-21.00)

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-20.00)

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 C 10.2, Green Generation Program.

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, 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 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.

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:

	$/kWh	
Off-Peak – Summer	$0.084091	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak – Summer	$0.120119	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak – Summer	$0.162840	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak – Winter	$0.076648	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak – Winter	$0.088553	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-4.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$0.042154	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-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-21.20)

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-21.10)

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***

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: $(0.000751) 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.

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C 1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self - generated will be charged as described in the Delivery Charges section of this Rate Schedule.

(Continued on Sheet No. D-21.30)

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-21.20)

Monthly Rate: (Contd)

Self-Generation Provision (SG): (Contd)

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

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). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

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 C 10.2, Green Generation 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 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, 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.

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.

Capacity Charge:	$10.00	per kW for all kW of Peak Demand during the billing months of June-September
	$8.00	per kW for all kW of Peak Demand during the billing months of October-May
Energy Charge:	***$0.067209***	***per kWh for all kWh during the billing months of June-September.***
	$***0.065743***	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-4.00.

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:	$1.15	per kW for all kW of Peak Demand
Distribution Charge:	$***0.030042***	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-23.00)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-23.00)

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: $***(0.000614)*** 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.

Self-Generation Provision (SG):

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company’s system, which may employ cogeneration or small power production technology.

All facilities operated in parallel with the Company’s system must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission’s (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

(Continued on Sheet No. D-24.10)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-24.00)

Self-Generation Provision (SG) (Contd)

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). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

(Continued on Sheet No. D-25.00)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-24.10)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11, 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.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., 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.

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.

(Continued on Sheet No. D-25.10)

GENERAL SERVICE PRIMARY RATE GP

Availability:

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 (CVL 3)

Energy Charge:	$***0.094196***	per kWh for all kWh during the billing months of June-September
	$***0.092211***	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge	$***0.095996***	per kWh for all kWh during the billing months of June-September
	$***0.094011***	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge	$***0.090996***	per kWh for all kWh during the billing months of June-September
	$***0.089011***	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-4.00.

(Continued on Sheet No. D-27.10)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-27.00)

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 (CVL 3)

Distribution Charge: $***0.019354*** per kWh for all kWh

Charges for Customer Voltage Level 2 (CVL 2)

Distribution Charge: $***0.012222*** per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL 1)

Distribution Charge: $***0.009347*** per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

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.

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.

Substation Ownership Credit: $ ***(0.000467)*** 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.

(Continued on Sheet No. D-28.00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-27.10)

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: $ ***(0.000557)*** 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.

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

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). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

(Continued on Sheet No. D-29.00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-28.00)

Sheet reserved for future use

(Continued on Sheet No. D-29.10)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-29.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11, 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.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11, 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.

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 shall 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, or (v) 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.

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 (CVL 3)

Capacity Charge:	$***22.24***	per kW of On-Peak Billing Demand during the billing months of June-September
	$***21.24***	per kW of On-Peak Billing Demand during the billing months of October-May
Energy Charge:	$***0.052166***	per kWh for all On-Peak kWh during the billing months of June-September
	$***0.034298***	per kWh for all Off-Peak kWh during the billing months of June-September
	$***0.042407***	per kWh for all On-Peak kWh during the billing months of October-May
	$***0.037135***	per kWh for all Off-Peak kWh during the billing months of October-May

Charges for Customer Voltage Level 2 (CVL 2)

Capacity Charge:	$***21.24***	per kW of On-Peak Billing Demand during the billing months of June-September
	$***20.24***	per kW of On-Peak Billing Demand during the billing months of October-May
Energy Charge:	$***0.053966***	per kWh for all On-Peak kWh during the billing months of June-September
	$***0.036098***	per kWh for all Off-Peak kWh during the billing months of June-September
	$***0.044207***	per kWh for all On-Peak kWh during the billing months of October-May
	$***0.038935***	per kWh for all Off-Peak kWh during the billing months of October-May

(Continued on Sheet No. D-31.10)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-31.00)

Monthly Rate: (Contd)

Power Supply Charges: These charges are applicable to Full Service Customers. (Contd)

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge:	$***20.24***	per kW of On-Peak Billing Demand during the billing months of June-September
	$***19.24***	per kW of On-Peak Billing Demand during the billing months of October-May
Energy Charge:	$***0.048966***	per kWh for all On-Peak kWh during the billing months of June-September
	$***0.031098***	per kWh for all Off-Peak kWh during the billing months of June-September
	$***0.039207***	per kWh for all On-Peak kWh during the billing months of October-May
	$***0.033935***	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-4.00.

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 (CVL 3)

Capacity Charge: $***4.92*** per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL 2)

Capacity Charge: $***2.07*** per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge: $***1.14*** per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

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-32.00)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-31.10)

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 l***ess than 60% of the highest on-peak billing demand of the preceding billing months of 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.

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:	$***(0.64)***	per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit:	***$(0.44)***	***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.

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.

(Continued on Sheet No. D-33.00)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-33.00)

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: $ ***(0.000326)*** 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-34.10)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-34.00)

Monthly Rate: (Contd)

Self-Generation Provision (SG):

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

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). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Interruptible Service Provision (GI):

This provision is available to any customer account willing to contract for at least 500 kW of On-Peak Billing Demand as interruptible. The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed 50,000 kW. The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to 250,000 kW.

The customer may choose to have the interruptible load separately metered. The customer shall bear any expense incurred by the Company in providing a separate service for the interruptible portion of an existing customer load. The customer must provide space suitable for the separate metering.

(Continued on Sheet No. D-35.00)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-34.10)

Monthly Rate: (Contd)

Interruptible Service Provision (GI): (Contd)

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. All contracts under this provision shall be negotiated on an annual basis. Within ~~10~~ *30* minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity or have the total facility subject to interruption.

The minimum On-Peak Billing Demand that shall be billed for the interruptible portion of a customer's bill is the contracted interruptible amount. At the Company's discretion, the customer may reduce 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 as determined by the Company and may require the installation and maintenance of equipment that allow the Company to remotely interrupt the customer's load. If the company determines it is required to install and maintain equipment at the customer's site to comply with any requirements associated with the GI service provision then it shall do so at the customer's expense. In addition, the customer shall also adhere to any advance notification requirements the Company deems are necessary to comply with its obligations to MISO under this provision.

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 endeavor to provide notice in advance of probable interruption, and if possible, a second notice of positive interruption. However, this service shall be interrupted immediately upon notice should the Company deem such action necessary. 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.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $50.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Interruptible Credit:	$(7.00)	per kW of On-Peak Billing Demand during the billing months of June-September
	$***(6.00)***	per kW of On-Peak Billing Demand during the billing months of October-May

(Continued on Sheet No. D-36.00)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-35.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., 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.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., 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.

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 applicable any 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 shall 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 Resale Service Provision, (ii) service under the Green Generation Program, (iii) service under the Educational Institution Service Provision, (iv) service under the Aggregate Peak Demand Service Provision, (v) service under the Interruptible Service Provision, 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.

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

Availability:

Subject to any restrictions, General Service Primary Time-Of-Use (GPTU) Rate is available to any Full Service Customer taking service at the Company's Primary Voltage level.

Nature of Service:

Service under the 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 normal 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 measuring equipment available to provide the Company with the metering data necessary for billing purposes.

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 12:00 PM and 7:00 PM to 11:00 PM
Mid-Peak Hours:	12:00 PM to 2:00 PM and 5:00 PM to 7:00 PM
High-Peak Hours:	2:00 PM to 5:00 PM
Winter:	
Off-Peak Hours:	12:00 AM to 2:00 PM and 9:00 PM to 12:00 AM
Mid-Peak Hours:	2:00 PM to 4:00 PM and 7:00 PM to 9:00 PM
High-Peak Hours:	4:00 PM to 7:00 PM

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 a 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-36.20)

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-36.10)

Monthly Rate:

Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL 3)

Energy Charge:

Off-Peak - Summer	$***0.069849***	per kWh during the calendar months of June - September
Low-Peak - Summer	$***0.092040***	per kWh during the calendar months of June - September
Mid-Peak - Summer	$***0.117719***	per kWh during the calendar months of June - September
High-Peak - Summer	$***0.134017***	per kWh during the calendar months of June - September
Off-Peak - Winter	$***0.073700***	per kWh during the calendar months of October - May
Mid-Peak - Winter	$***0.086293***	per kWh during the calendar months of October - May
High-Peak - Winter	$***0.089541***	per kWh during the calendar months of October - May

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

Off-Peak - Summer	$***0.071649***	per kWh during the calendar months of June - September
Low-Peak - Summer	$***0.093840***	per kWh during the calendar months of June - September
Mid-Peak - Summer	$***0.119519***	per kWh during the calendar months of June - September
High-Peak - Summer	$***0.135817***	per kWh during the calendar months of June - September
Off-Peak - Winter	$***0.075500***	per kWh during the calendar months of October - May
Mid-Peak - Winter	$***0.088093***	per kWh during the calendar months of October - May
High-Peak - Winter	$***0.091341***	per kWh during the calendar months of October - May

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge:

Off-Peak - Summer	$***0.066649***	per kWh during the calendar months of June - September
Low-Peak - Summer	$***0.088840***	per kWh during the calendar months of June - September
Mid-Peak - Summer	$***0.114519***	per kWh during the calendar months of June - September
High-Peak - Summer	$***0.130817***	per kWh during the calendar months of June - September
Off-Peak - Winter	$***0.070500***	per kWh during the calendar months of October - May
Mid-Peak - Winter	$***0.083093***	per kWh during the calendar months of October - May
High-Peak - Winter	$***0.086341***	per kWh during the calendar months of October - May

Delivery Charges:

System Access Charge: $***200.00*** per customer per month

Charges for Customer Voltage Level 3 (CVL 3)

Capacity Charge: $***4.92*** per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL 2)

Capacity Charge: $***2.07*** per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge: $***1.14*** per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-36.30)

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-36.20)

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.

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: $***(0.64)*** per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $(0.44) 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: $(0.000326) 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-36.40)

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-36.30)

Self-Generation Provision (SG)

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

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). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

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.

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 shall require a written contract with a minimum term of one year.

ENERGY INTENSIVE PRIMARY RATE EIP

Availability:

Subject to any restrictions, the Energy Intensive Primary Rate EIP is available to any Full Service electric metal melting customer taking service at the Company's Primary Voltage levels, where the electric load on this rate is utilized for industrial metal melting processes such as electric arc or induction furnaces or to any Full Service electric industrial customer who qualified as energy intensive as defined herein. ***E***xisting metal melting customers taking service under the Company's ***former Metal Melting Primary Pilot as of November 30, 2015 are eligible for service on Rate EIP***. An additional 200 MW of Maximum Demand capacity will be available on a first-come, first-served basis to Full Service customers with new electric metal melting or energy intensive industrial load not previously served by the Company. To qualify as energy intensive load, the customer must demonstrate viable options to site the production outside of the state and the customer's incremental load must exceed 2 MW at a single site ***with*** an annual load factor that exceeds 70% ***or the customer's incremental load must exceed 15 MW with a minimum of 75% of their total consumption occurring during Off-Peak Hours***. New electric metal melting load must be separately metered. The customer must provide a special circuit or circuits in order for the Company to install separate metering.

Nature of Service:

Service under the 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 measuring equipment available to provide the Company with the metering data necessary for billing purposes.

For purposes of this rate, the appropriate measure of market price is the Real-Time LMP for the Company's retail aggregating node CONS.CETR established by the Midcontinent Independent System Operator Inc. (MISO).

Critical Peak Event Determination:

The Company shall call a Critical Peak Event to signal either the market price has exceeded an Economic Trigger Price or a system integrity event 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 and Load Management Measures - Stage 1. 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 the greater of 150% of the High Peak Energy Charge or the average market price 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.

(Continued on Sheet No. D-37.10)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-37.00)

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:	3:00 PM to 5:00 PM 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:	5:00 PM to 7:00 PM 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.

Monthly Rate:

Power Supply Charges:

<u>Charges for Customer Voltage Level 3 (CVL 3)</u>

Energy Charge:

Off-Peak - Summer	$***0.040349***	per kWh during the calendar months of June - September
Low-Peak - Summer	$***0.056447***	per kWh during the calendar months of June - September
Mid-Peak - Summer	$***0.075074***	per kWh during the calendar months of June - September
High-Peak - Summer	$***0.086898***	per kWh during the calendar months of June - September
Critical Peak - Summer	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	$***0.043142***	per kWh during the calendar months of October - May
Mid-Peak - Winter	$***0.052278***	per kWh during the calendar months of October - May
High-Peak- Winter	$***0.054634***	per kWh during the calendar months of October - May
Critical Peak - Winter	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-37.20

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-37.10)

Power Supply Charges: (Contd)

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

Off-Peak - Summer	$***0.051349***	per kWh during the calendar months of June - September
Low-Peak - Summer	$***0.067447***	per kWh during the calendar months of June - September
Mid-Peak - Summer	$***0.086074***	per kWh during the calendar months of June - September
High-Peak - Summer	$***0.097898***	per kWh during the calendar months of June - September
Critical Peak – Summer	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	$***0.054142***	per kWh during the calendar months of October - May
Mid-Peak - Winter	$***0.063278***	per kWh during the calendar months of October - May
High-Peak- Winter	$***0.065634***	per kWh during the calendar months of October - May
Critical Peak - Winter	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 1 (CVL 1)

Energy Charge:

Off-Peak - Summer	$***0.048349***	per kWh during the calendar months of June - September
Low-Peak - Summer	$***0.064447***	per kWh during the calendar months of June - September
Mid-Peak - Summer	$***0.083074***	per kWh during the calendar months of June - September
High-Peak - Summer	$***0.094898***	per kWh during the calendar months of June - September
Critical Peak - Summer	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	$***0.051142***	per kWh during the calendar months of October - May
Mid-Peak - Winter	$***0.060278***	per kWh during the calendar months of October - May
High-Peak- Winter	$***0.062634***	per kWh during the calendar months of October - May
Critical Peak - Winter	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	

Delivery Charges:

System Access Charge: $***200.00*** per customer per month

Charges for Customer Voltage Level 3 (CVL 3):

Capacity Charge: $***4.92*** per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL 2):

Capacity Charge: $***2.07*** per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1):

Capacity Charge: $***1.14*** per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-37.30)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-37.20)

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.

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: $***(0.64)*** per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $(0.44) 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 Provision (SG):

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

(Continued on Sheet No. D-37.40)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-37.30)

Self-Generation Provision (SG) (Contd)

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

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). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Green Generation Programs:

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.

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 shall require a written contract with a minimum term of one year.

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-42.00)

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*** 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. If the customer fails to meet this written notice requirement, the LMP shall be increased by applying a 10% adder.

Delivery Standby Charges:

<u>System Access Charge:</u>

Generator that does not meet or exceed load:	$100.00	per generator installation per month
Generator that meets or exceeds load:	$200.00	per generator installation per month

<u>Charges for Customer Voltage Level 1 (CVL 3)</u>

Capacity Charge:	$***4.92***	per kW of Standby Demand

<u>Charges for Customer Voltage Level 2 (CVL 2)</u>

Capacity Charge:	$***2.07***	per kW of Standby Demand

<u>Charges for Customer Voltage Level 1 (CVL 1)</u>

Capacity Charge:	$***1.14***	per kW of Standby Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-44.00)

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-42.00)

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: $***(0.64)*** per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $(0.44) 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.

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: $***(1.25)*** per kW of Standby 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.

(Continued on Sheet No. D-45.00)

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-44.00)

Monthly Rate: (Contd)

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).

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

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.

Minimum Charge:

The System Access Charge included in this Rate Schedule in addition to the customer's contracted Standby Capacity multiplied by the net of any Substation Ownership Credit and Delivery Capacity Charges of this Rate Schedule.

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:

Standby service and/or sales of energy to the Company under this rate shall require a written contract with a minimum term of one year.

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: $***0.052873*** per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-47.00)

GENERAL SERVICE METERED LIGHTING RATE GML

(Continued From Sheet No. D-46.00)

Monthly Rate: (Contd)

Secondary Delivery Charge:

System Access Charge:	$10.00	per customer per month
Distribution Charge:	$***0.055922***	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

Primary Power Supply Charge:

Energy Charge:	$***0.025948***	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Primary Delivery Charge:

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$***0.042091***	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., 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.B, Net Metering Program.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., 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.

(Continued on Sheet No. D-48.00)

GENERAL SERVICE METERED LIGHTING RATE GML

(Continued From Sheet No. D-47.00)

Monthly Rate: (Contd)

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.

Special Terms and Conditions:

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, annual charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

Hours of Lighting:

Metered Lights shall be controlled to burn only when the natural general level of illumination is lower than about 3/4 footcandle. Under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. For dusk to midnight service, luminaires shall be controlled to turn off anytime between 11:00 PM, Eastern standard time, and dawn. The turnoff time within a given municipality shall be the same at all locations.

Term and Form of Contract:

All service under this rate shall require a written contract with an initial term of five years or more.

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-50.10)

Monthly Rate:

The charge per luminaire per month shall be:

	Nominal Rating of Lamps (One Lamp per Luminaire) (1)				
Type of Luminaire	**Watts**	**Watts Including Ballast (2)**	**Lumens**	**Service Charge per Luminaire (4)**	**Fixture Charge per Luminaire (4)**
Mercury Vapor (3)	100	128	3,500	$ ***6.21***	$6.00
Mercury Vapor (3)	175	209	7,500	***10.14***	6.00
Mercury Vapor (3)	250	281	10,000	***13.63***	6.00
Mercury Vapor (3)	400	458	20,000	***22.22***	6.00
Mercury Vapor (3)	700	770	35,000	***37.36***	6.00
Mercury Vapor (3)	1,000	1,080	50,000	***52.40***	6.00
High-Pressure Sodium (3)	70	83	5,000	***4.03***	6.00
High-Pressure Sodium	100	117	8,500	***5.68***	6.00
High-Pressure Sodium	150	171	14,000	***8.30***	6.00
High-Pressure Sodium (3)	200	247	20,000	***11.99***	6.00
High-Pressure Sodium	250	318	24,000	***15.43***	6.00
High-Pressure Sodium	400	480	45,000	***23.29***	6.00
Fluorescent (3)	380	470	20,000	***22.81***	6.00
Incandescent (3)	202	202	2,500	***9.80***	6.00
Incandescent (3)	305	305	4,000	***14.80***	6.00
Incandescent (3)	405	405	6,000	***19.65***	6.00
Incandescent (3)	690	690	10,000	***33.48***	6.00
Metal Halide	150	170	9,750	***8.25***	6.00
Metal Halide (3)	175	210	10,500	***10.19***	6.00
Metal Halide	250	290	15,500	***14.07***	6.00
Metal Halide	400	460	24,000	***22.32***	6.00

(1) Ratings for fluorescent lighting apply to all lamps in one luminaire.

(2) Watts including ballast used for monthly billing of the Power Supply Cost Recovery (PSCR) Factor, Securitization and Securitization Tax Charges, Power Plant Securitization Charges and surcharges.

(3) Rates apply to existing luminaires only and are not open to new business.

(4) For customers who own their lighting fixtures and are assessed a Service Charge (but not a Fixture Charge), the charge per luminaire represents a ***37.2***% Power Supply Charge and a ***62.8***% Distribution Charge. For customers who do not own their lighting fixtures and are assessed both a Service Charge and a Fixture Charge, the charge per luminaire represents a ***21.8%*** Power Supply Charge and a ***78.2%*** Distribution Charge.

For energy conservation purposes, customers may, at their option, elect to have any or all luminaires served under this rate disconnected for a period of six months or more. The charge per luminaire per month, for each disconnected luminaire, shall be 40% of the monthly rate set forth above. However, should any such disconnected luminaire be reconnected at the customer's request after having been disconnected for less than six months, the monthly rate set forth above shall apply to the period of disconnection. An $8.00 per luminaire disconnect/reconnect charge shall be made at the time of disconnection except that when the estimated disconnect/reconnect cost is significantly higher than $8.00, the estimated cost per luminaire shall be charged.

For 24-hour mercury-vapor service, the charge per luminaire shall be 125% of the foregoing rates.

(Continued on Sheet No. D-52.00)

GENERAL UNMETERED EXPERIMENTAL LIGHTING RATE GU-XL

(Continued From Sheet No. D-54.01)

Facilities Policy (Contd)

Company-Owned Option (Contd)

D. The Company will determine the type and size of all experimental 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 experimental lighting available under this rate.
E. The Company shall determine all associated equipment necessary to provide service under the Company-Owned Unmetered Experimental Lighting option.
F. Any charges, deposits or contributions may be required in advance of commencement of construction.

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:

Power Supply Charges:

Energy Charge:	$***0.051599***	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges Customer-Owned Option:

Distribution Charge:	$***0. 097210***	per kWh for all kWh

Delivery Charges Company-Owned Option:

Distribution Charge:	$***0.119232***	per kWh for all kWh
Fixture Charge per Luminaire:	$6.00	per month

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

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.

Determination of Monthly Kilowatt-Hours and Burning Hours per Month Based on 4,200 Burning Hours per Year:

The monthly kilowatt-hours shall be determined by multiplying the total capacity requirements in watts (including the lamps, ballasts, drivers, and control devices) times the monthly Burning Hours as defined below divided by 1,000. 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, and modifying the lighting contract with the Company accordingly.

Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
457.8	382.2	369.6	306.6	264.6	226.8	252.0	298.2	336.0	399.0	432.6	474.6	4,200

Hours of Lighting:

Unmetered Experimental Lighting shall be burning at all times when the natural general level of illumination is lower than about 3/4 footcandle, and under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. Lighting service will be supplied from dusk to dawn every night and all night on an operating schedule of approximately 4,200 hours per year.

(Continued on Sheet No. D-54.03)

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:	$***0.073436***	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges:

System Access Charge:	$2.00	per customer per month
Distribution Charge:	$***0.014975***	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-55.00)

GENERAL SERVICE UNMETERED RATE GU

(Continued From Sheet No. D-55.00)

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 provisions contained in Rule C10.2, Green Generation 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 ***plus 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.

Special Terms and Conditions:

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, monthly charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

Term and Form of Contract:

Traffic Lighting, Wireless Access and Security Camera service under this rate may require a written contract for a term of reasonable duration.

All service under this rate to Community Antenna Television Service Companies shall require a written contract with a minimum term of one year.

P R O O F O F S E R V I C E

STATE OF MICHIGAN)

Case No. U-17990

County of Ingham)

Gloria Pearl Jones being duly sworn, deposes and says that on February 28, 2017 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).

Gloria Pearl Jones

Gloria Pearl Jones

Subscribed and sworn to before me
this 28th day of February 2017

Lisa Felice

Lisa Felice
Notary Public, Eaton County
My Commission Expires April 15, 2020

Service List -- Case No. U-17990

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