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, on the Commission's own motion, to open a docket to implement the provisions of Section 6w of 2016 PA 341 for **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** service territory.	))))))	Case No. U-18253

At the November 30, 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

History of Proceedings

MCL 460.6w (Section 6w) was added to 1939 PA 3, MCL 460.1 *et seq.*, by passage of 2016 PA 341. Section 6w provides for the Commission to establish a state reliability mechanism (SRM). On February 28, 2017, the Commission commenced this proceeding to implement Section 6w for Upper Michigan Energy Resources Corporation (UMERC) and other named utilities, and, as a result of rulings by the Federal Energy Regulatory Commission (FERC),[1] also

[1] On February 2, 2017, the FERC issued an order (February 2 order) rejecting the Midcontinent Independent System Operator, Inc.'s (MISO) Competitive Retail Solution (CRS) tariff filing in Docket No. ER17-284-000. The FERC determined that the Forward Resource Auction (FRA) proposed by MISO, which would apply to a small amount of load within MISO and would occur more than three years prior to MISO's existing Planning Resource Auction (PRA), would bifurcate the MISO capacity market and have potential adverse impacts on price. February 2 order, p. 2. The FERC did not expressly comment on the Prevailing State Compensation Mechanism (PSCM) proposal that was set forth in MISO's CRS filing. Notwithstanding, the Commission understands that the PSCM was also rejected in the February 2

suspended the schedule in other related dockets and sought public comment on whether to move forward and establish a SRM for UMERC and the other utilities. On March 10, 2017, the Commission summarized the public comments received and concluded that there was no immediate need to place the proceedings for UMERC and other utilities located in Michigan's Upper Peninsula (UP) on the same fast track as the schedule of proceedings for Consumers Energy Company (Consumers) and DTE Electric Company (DTE Electric). Instead, the Commission encouraged the UP utilities, the Commission Staff (Staff), and the other interested entities to participate in a collaborative effort to be conducted by the Staff. The Staff sent letters on March 20 and April 11, 2017, inviting the UP utilities, the Association of Businesses Advocating Tariff Equity, the Sierra Club, Constellation NewEnergy, Inc. (CNE), and Verso Corporation (Verso) to participate in workgroup meetings on April 11 and 26, 2017, respectively. No resolution of SRM-related issues for these UP utilities was reached.

Because the statutory deadline for the Commission to establish SRMs applicable to the UP utilities is December 1, 2017, the Commission issued an order on May 31, 2017, setting dates for intervention, as well as an initial prehearing conference, to establish a schedule in this and other proceedings involving the other UP utilities.

On June 28, 2017, Administrative Law Judge Sharon L. Feldman (ALJ) held a prehearing conference at which intervenor status was granted to Verso, CNE, and the Michigan Electric Cooperative Association (MECA). UMERC and the Staff also participated. At the prehearing conference, the ALJ approved a schedule going forward and directed UMERC to file an application regarding an SRM charge by July 25, 2017.

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order. The Commission eventually concluded that further efforts to implement Section 6w(1) of Act 341 were no longer required. March 10, 2017 order (March 10 order), p. 18.

On July 25, 2017, UMERC filed its application, along with supporting testimony and exhibits, for an SRM capacity charge under Section 6w of Act 341.[2] On August 28, 2017, testimony and exhibits were filed by the Staff, CNE, and MECA. On September 8, 2017, UMERC filed rebuttal testimony.

An evidentiary hearing was held on September 18, 2017. On October 5, 2017, initial briefs were filed by UMERC, the Staff, Verso, CNE, and MECA. On October 17, 2017, reply briefs were filed by UMERC, the Staff, CNE, and MECA.

The record consists of 102 pages of transcript and 18 exhibits admitted into evidence. In order to issue an order no later than December 1, 2017, as Section 6w requires, the Commission has decided to read the record in this case.

<u>Background</u>

MCL 460.6w(12)(h) defines the SRM[3] as "a plan adopted by the commission in the absence of a [PSCM] to ensure reliability of the electric grid in this state consistent with [MCL 460.6w(8)]." Pertinent subsections of MCL 460.6w related to SRM, state reliability charge, and the capacity obligations and process are as follows:

> (2) . . . If, by September 30, 2017, the Federal Energy Regulatory Commission does not put into effect a resource adequacy tariff that includes a capacity forward auction or a prevailing state compensation mechanism, then the commission shall establish a state reliability mechanism under subsection (8). The commission may commence a proceeding before October 1 if the commission believes orderly administration would

[2] Pursuant to a series of orders issued in Case No. U-18197 and the March 10 order in this matter, the Staff has held a number of technical conferences for the purpose of addressing the procedures and requirements for demonstrating capacity. The result of those conferences was the September 15, 2017 order in Case No. U-18197 (September 15 order).

[3] The final sentence of Section 6w(2) refers to establishment of a "state reliability charge" in the same manner as a "capacity charge" under Section 6w(3). The remainder of Section 6w refers to the state reliability mechanism or SRM. "SRM charge" or "capacity charge" are used interchangeably throughout this order to refer to the state reliability charge.

be enabled by doing so. If the commission implements a state reliability mechanism, it shall be for a minimum of 4 consecutive planning years beginning in the upcoming planning year. A state reliability charge must be established in the same manner as a capacity charge under subsection (3) and be determined consistent with subsection (8). . . .

(3) After the effective date of the amendatory act that added section 6t, the commission shall establish a capacity charge as provided in this section. A determination of a capacity charge must be conducted as a contested case pursuant to chapter 4 of the administrative procedures act of 1969, 1969 PA 306, MCL 24.271 to 24.287, after providing interested persons with notice and a reasonable opportunity for a full and complete hearing and conclude by December 1 of each year. The commission shall allow intervention by interested persons, alternative electric suppliers, and customers of alternative electric suppliers and the utility under consideration. The commission shall provide notice to the public of the single capacity charge as determined for each territory. No new capacity charge is required to be paid before June 1, 2018. The capacity charge must be applied to alternative electric load that is not exempt as set forth under subsections (6) and (7). If the commission elects to implement a capacity forward auction for this state as set forth in subsection (1) or (2), then a capacity charge shall not apply beginning in the first year that the capacity forward auction for this state is effective. In order to ensure that noncapacity electric generation services are not included in the capacity charge, in determining the capacity charge, the commission shall do both of the following and ensure that the resulting capacity charge does not differ for full service load and alternative electric supplier load:

(a) For the applicable term of the capacity charge, include the capacity-related generation costs included in the utility's base rates, surcharges, and power supply cost recovery factors, regardless of whether those costs result from utility ownership of the capacity resources or the purchase or lease of the capacity resource from a third party.

(b) For the applicable term of the capacity charge, subtract all non-capacity-related electric generation costs, including, but not limited to, costs previously set for recovery through net stranded cost recovery and securitization and the projected revenues, net of projected fuel costs, from all of the following:

(i) All energy market sales.

(ii) Off-system energy sales.

(iii) Ancillary services sales.

(iv) Energy sales under unit-specific bilateral contracts.

(4) The commission shall provide for a true-up mechanism that results in a utility charge or credit for the difference between the projected net revenues described in

subsection (3) and the actual net revenues reflected in the capacity charge. The true-up shall be reflected in the capacity charge in the subsequent year. The methodology used to set the capacity charge shall be the same methodology used in the true-up for the applicable planning year.

(5) Not less than once every year, the commission shall review or amend the capacity charge in all subsequent rate cases, power supply cost recovery cases, or separate proceedings established for that purpose.

(6) A capacity charge shall not be assessed for any portion of capacity obligations for each planning year for which an alternative electric supplier can demonstrate that it can meet its capacity obligations through owned or contractual rights to any resource that the appropriate independent system operator allows to meet the capacity obligation of the electric provider. The preceding sentence shall not be applied in any way that conflicts with a federal resource adequacy tariff, when applicable. Any electric provider that has previously demonstrated that it can meet all or a portion of its capacity obligations shall give notice to the commission by September 1 of the year 4 years before the beginning of the applicable planning year if it does not expect to meet that capacity obligation and instead expects to pay a capacity charge. The capacity charge in the utility service territory must be paid for the portion of its load taking service from the alternative electric supplier not covered by capacity as set forth in this subsection during the period that any such capacity charge is effective.

(7) An electric provider shall provide capacity to meet the capacity obligation for the portion of that load taking service from an alternative electric supplier in the electric provider's service territory that is covered by the capacity charge during the period that any such capacity charge is effective. The alternative electric supplier has the obligation to provide capacity for the portion of the load for which the alternative electric supplier has demonstrated an ability to meet its capacity obligations. If an alternative electric supplier ceases to provide service for a portion or all of its load, it shall allow, at a cost no higher than the determined capacity charge, the assignment of any right to that capacity in the applicable planning year to whatever electric provider accepts that load.

(8) If a state reliability mechanism is required to be established under subsection (2), the commission shall do all of the following:

(a) Require, by December 1 of each year, that each electric utility demonstrate to the commission, in a format determined by the commission, that for the planning year beginning 4 years after the beginning of the current planning year, the electric utility owns or has contractual rights to sufficient capacity to meet its capacity obligations as set by the appropriate independent system operator, or commission, as applicable.

(b) Require, by the seventh business day of February each year, that each alternative electric supplier, cooperative electric utility, or municipally owned electric utility demonstrate to the commission, in a format determined by the commission, that for the planning year beginning 4 years after the beginning of the current planning year, the alternative electric supplier, cooperative electric utility, or municipally owned electric utility owns or has contractual rights to sufficient capacity to meet its capacity obligations as set by the appropriate independent system operator, or commission, as applicable. One or more municipally owned electric utilities may aggregate their capacity resources that are located in the same local resource zone to meet the requirements of this subdivision. One or more cooperative electric utilities may aggregate their capacity resources that are located in the same local resource zone to meet the requirements of this subdivision. A cooperative or municipally owned electric utility may meet the requirements of this subdivision through any resource, including a resource acquired through a capacity forward auction, that the appropriate independent system operator allows to qualify for meeting the local clearing requirement. A cooperative or municipally owned electric utility's payment of an auction price related to a capacity deficiency as part of a capacity forward auction conducted by the appropriate independent system operator does not by itself satisfy the resource adequacy requirements of this section unless the appropriate independent system operator can directly tie that provider's payment to a capacity resource that meets the requirements of this subsection. By the seventh business day of February in 2018, an alternative electric supplier shall demonstrate to the commission, in a format determined by the commission, that for the planning year beginning June 1, 2018, and the subsequent 3 planning years, the alternative electric supplier owns or has contractual rights to sufficient capacity to meet its capacity obligations as set by the appropriate independent system operator, or commission, as applicable. If the commission finds an electric provider has failed to demonstrate it can meet a portion or all of its capacity obligation, the commission shall do all of the following:

(i) For alternative electric load, require the payment of a capacity charge that is determined, assessed, and applied in the same manner as under subsection (3) for that portion of the load not covered as set forth in subsections (6) and (7). If a capacity charge is required to be paid under this subdivision in the planning year beginning June 1, 2018 or any of the 3 subsequent planning years, the capacity charge is applicable for each of those planning years.

(ii) For a cooperative or municipally owned electric utility, recommend to the attorney general that suit be brought consistent with the provisions of subsection (9) to require that procurement.

(iii) For an electric utility, require any audits and reporting as the commission considers necessary to determine if sufficient capacity is procured. If an electric utility fails to meet its capacity obligations, the commission may assess appropriate and reasonable fines, penalties, and customer refunds under this act.

(c) In order to determine the capacity obligations, request that the appropriate independent system operator provide technical assistance in determining the local clearing requirement and planning reserve margin requirement. If the appropriate independent system operator declines, or has not made a determination by October 1 of that year, the commission shall set any required local clearing requirement and planning reserve margin requirement, consistent with federal reliability requirements.

(d) In order to determine if resources put forward will meet such federal reliability requirements, request technical assistance from the appropriate independent system operator to assist with assessing resources to ensure that any resources will meet federal reliability requirements. If the technical assistance is rendered, the commission shall accept the appropriate independent system operator's determinations unless it finds adequate justification to deviate from the determinations related to the qualification of resources. If the appropriate independent system operator declines, or has not made a determination by February 28, the commission shall make those determinations. . . .

* * *

(12) As used in this section:

(a) "Appropriate independent system operator" means the Midcontinent Independent System Operator. . . .

* * *

(c) "Electric provider" means any of the following:
(i) Any person or entity that is regulated by the commission for the purpose of selling electricity to retail customers in this state.
(ii) A municipally owned electric utility in this state.
(iii) A cooperative electric utility in this state.
(iv) An alternative electric supplier licensed under section 10a.

(d) "Local clearing requirement" means the amount of capacity resources required to be in the local resource zone in which the electric provider's demand is served to ensure reliability in that zone as determined by the appropriate independent system operator for the local resource zone in which the electric provider's demand is served and by the commission under subsection (8).

(e) "Planning reserve margin requirement" means the amount of capacity equal to the forecasted coincident peak demand that occurs when the appropriate independent system operator footprint peak demand occurs plus a reserve margin that meets an acceptable loss of load expectation as set by the commission or the appropriate independent system operator under subsection (8). . . .

* * *

(h) "State reliability mechanism" means a plan adopted by the commission in the absence of a prevailing state compensation mechanism to ensure reliability of the electric grid in this state consistent with subsection (8).

Thus, Section 6w of Act 341 requires each electric utility, alternative electric supplier (AES), cooperative electric utility, and municipally-owned electric utility to demonstrate to the Commission, in a format determined by the Commission, that the load serving entity (LSE or electric provider) owns or has contractual rights to sufficient capacity to meet its capacity obligations as set by the appropriate independent system operator (ISO), or by the Commission, as applicable. In the event an AES cannot make the required capacity showing (or elects not to), Section 6w requires that an SRM capacity charge be assessed, to be determined by the Commission, with the associated capacity for such AES customers provided by the incumbent utility. Section 6w established a new framework for resource adequacy in Michigan – that is, ensuring electric providers can meet customers' electricity needs over the long-term even during periods of high electricity consumption or when power plants or transmission lines unexpectedly go out of service. Act 341 went into effect on April 20, 2017.

Pursuant to a series of orders issued in Case No. U-18197 and the March 10 order in this matter, the Staff held a number of technical conferences for the purpose of addressing the procedures and requirements for demonstrating capacity. The Commission engaged stakeholders, with opportunities to provide comments and positions, and also opened dockets in this case and in Case Nos. U-18239, U-18248, U-18254, and U-18258, for the five electric providers with choice load potentially affected by the SRM charge requirement of Section 6w.

Under the Section 6w framework, the Commission must determine the capacity obligations for individual electric providers over a four-year period and create a process to evaluate whether such obligations are met. Section 6w provides remedies in instances when an electric provider is unable to demonstrate it has procured adequate capacity to cover its load, including allowing for uncovered AES load to be assessed a capacity charge determined by the Commission and paid to the incumbent utility in exchange for meeting that load's capacity obligations. Special provisions exist for electric utilities, municipally-owned utilities, and electric cooperatives that fail to meet the Section 6w capacity obligations. Whether any capacity charge is actually imposed on choice customers will be determined after February 9, 2018, when AESs make their capacity demonstrations. However, under Section 6w(3), the capacity charge must be established by the Commission after a contested case by December 1 of each year, and the charge may not go into effect prior to June 1, 2018.

In the September 15 order, the Commission adopted a timeline and procedures for the capacity demonstration process referred to in Section 6w(6) and (8). In the September 15 order in Case No. U-18441, the Commission opened the docket that will be the repository for all of the electric providers' filings for the initial demonstrations for planning years 2018-2021. Under the approved timeline, the Staff will file a memo in that docket indicating its determination on each electric provider's demonstration by March 6, 2018. Show cause proceedings shall be initiated if an individual LSE does not appear to have sufficient capacity based on the Staff's assessment. Such a proceeding will provide an opportunity for parties to present evidence on whether the electric provider has failed to demonstrate it can meet a portion or all of its capacity obligations, thereby triggering Commission action as set forth in Section 6w(8)(b)(i). The instant order will determine the capacity charge associated with choice load in UMERC's service territory. Whether the charge is levied on any retail open access (ROA) customers will be determined by the outcome of any orders to show cause issued after March 6, 2018, for AESs operating in UMERC's service territory.

Positions of the Parties

Direct Testimony

Upper Michigan Energy Resources Corporation

Dennis M. Derricks, Director of Regulatory Affairs at WEC Energy Group, Inc., testified that UMERC was established as a Michigan-regulated utility to provide electric and natural gas service to Michigan customers that were formerly customers of Wisconsin Electric Power Company (WEPCo) and Wisconsin Public Service Corporation (WPS Corp). UMERC provides electric service to approximately 36,500 full-requirements customers and retail natural gas service to approximately 5,300 full-requirements customers. 2 Tr 20. The focus of his testimony in this proceeding is the source of power supply for UMERC and the proposed capacity charges applicable for UMERC's electric customers that are served by an AES, for which adequate generation capacity has not been demonstrated. 2 Tr 19. Mr. Derricks sponsored as two exhibits, one purchase power agreement (PPA), between WEPCo and UMERC (Exhibit A-1), and one PPA between WPS Corp and UMERC (Exhibit A-2), as well as proposed tariff sheet revisions to implement UMERC's SRM capacity charge (Exhibit A-3). These PPAs cover the customer load in the geographic areas where WEPCo and WPS Corp used to provide electric service to their former customers, provide all of UMERC's power supply requirements, are formula-based, and are intended to be a bridge, rather than a long-term generation source, until a long-term energy solution is implemented in the UP. 2 Tr 20-21.

UMERC proposed to use the capacity rates of the two PPAs that provide UMERC's power supply to comply with MCL 460.6w. 2 Tr 21. Mr. Derricks testified that the PPAs are wholesale transactions subject to FERC regulation and were approved by the FERC on December 28, 2016. 2 Tr 22. Mr. Derricks further testified that both PPAs utilize cost-based formula rates that the FERC previously approved and determined to be "just and reasonable" in WPS Corp and WEPCo FERC rate cases. *Id*. Further, Mr. Derricks explained that the Commission's April 13, 2017 order in Case No. U-18149 approved UMERC's 2017 power supply cost recovery (PSCR) plan that included the PPAs' capacity costs. *Id*.

Mr. Derricks next explained how PPA capacity costs that UMERC would recover via the SRM capacity charge would comply with MCL 460.6w(3)(b). Because this provision requires the exclusion of certain non-capacity-related electric generation costs, Mr. Derricks testified that the capacity formula rate only includes capacity-related generation costs and not non-capacity costs or energy-related costs. Additionally, Mr. Derricks noted that UMERC only purchases and pays for the amount of capacity it actually uses under the PPAs and that UMERC will not be making any off-system, market energy sales or ancillary service sales while the PPAs are in effect. Regarding compliance with MCL 460.6w(4), Mr. Derricks testified that the PPA charges are initially billed on an estimated basis and trued up the following year. UMERC will provide a refund or charge to reflect the difference between the estimated and actual $/kilowatt (kW). Mr. Derricks explained that the UMERC retail access service tariff implementing the SRM capacity charge reflects this methodology and eliminates the need to address it in other Commission proceedings. Finally, Mr. Derricks interprets Section 6w as requiring a minimum four-year period for the proposed SRM capacity charge mechanism to remain in place and UMERC proposed that the SRM charge remain in place indefinitely. 2 Tr 26.

Regarding the manner in which AESs shall demonstrate that they have sufficient capacity to meet their load obligations as provided pursuant to the SRM, UMERC defers to the Commission's decision in its September 15 order. Further, Mr. Derricks testified that, in the event that an AES's projected load changes between the annual demonstration and the applicable planning year four years later, the Commission should allow a means for annual true-up of load projections to ensure that the appropriate customers are being charged for utility-provided capacity. Again, Mr. Derricks testified that UMERC defers to the Commission's direction on this issue in its September 15 order.[4] 2 Tr 27. Likewise, if a customer's ROA load becomes subject to the SRM capacity charge, but subsequently that customer's AES supplier makes a demonstration that it can meet the resource adequacy requirements of the SRM for that customer's load in a subsequent year after it previously failed to make such a demonstration for the customer, UMERC defers to the Commission's direction in its September 15 order regarding whether the customer will be relieved of paying the SRM capacity charge to the utility.

<u>The Commission Staff and Intervenor Testimony</u>

Eric W. Stocking, an Economic Specialist in the Commission's Financial Analysis and Audit Division (FAAD), testified that, consistent with Section 6w(2), the SRM should be in effect in perpetuity, or until Act 341 is revised, because the SRM provides the Commission with a tool to ensure the long-term reliability of the grid and provides an economic incentive to LSEs to plan for future capacity obligations. 2 Tr 89-90. The Staff agrees with UMERC's proposal to have an SRM charge in place indefinitely, provided that Mr. Derricks is referring to the term of the SRM. 2 Tr 90. Mr. Stocking maintained that the term of the capacity charge is one year and that the capacity charge may only be assessed for AES load (for any planning year (PY)) for which the AES was unable to demonstrate an ability to meet. "For any years in which the AES is able to demonstrate that it has owned or contracted resources that satisfy its capacity obligations, no capacity charge should be levied onto that particular AES's customers." 2 Tr 91.

Mr. Stocking opined that, under Section 6w(8)(b)(i), in the initial four-year period beginning June 1, 2018, any portion of AES load that is not supported by a satisfactory capacity

[4] Although Mr. Derricks refers to the Commission's September 28, 2017 order in his testimony, it is clear he is referring to the September 15 order. Accordingly, the Commission refers to the proper date of September 15, 2017, instead of September 28, 2017, throughout this order.

demonstration in any one of those first four PYs would be subject to the capacity charge for those four years. Beginning with PY five and thereafter, Mr. Stocking further opined that the AES may annually demonstrate that has owned or contracted resources to meet its capacity obligations, and its customers would no longer be subject to the capacity charge for that PY. 2 Tr 92.

Mr. Stocking testified that the Staff agrees with UMERC that the Commission will identify the process for an SRM capacity demonstration and will determine whether the Commission will allow an annual true up or reconciliation of load projections elsewhere in a separate docket. 2 Tr 92-93. Mr. Stocking further testified that the Staff disagrees with some of the language UMERC proposed in its retail access service tariff based on the Staff's objection to portions of UMERC's proposed SRM calculation described in the testimony of Staff witness Nicholas Revere. 2 Tr 94.

Nicholas M. Revere, Manager of the Rates and Tariff Section of the Commission's Regulated Energy Division, presented the Staff's calculation of the capacity charge. He opined that the appropriate cost of capacity is the cost of new entry (CONE), or the cost to build a combustion turbine (CT). He testified that UMERC proposed to use the PPA capacity charges from the FERC formula rate tariff under which UMERC purchases power to comply with Section 6w, but opined that this proposal does not meet the requirements of Section 6w as it fails to include the capacity costs included in UMERC's rates. 2 Tr 76. The Staff, on the other hand, went through the cost of service study (COSS) for the former utilities replaced by UMERC, i.e., WEPCo and WPS Corp, and identified costs that are capacity related, and then considered all other costs non-capacity. Exhibits S-1.1 and S-1.3.

Mr. Revere stated that the Staff identified all costs currently classified as production-demand related and excluded those costs not directly incurred to provide capacity service. 2 Tr 76. He goes on to state:

> An alternative methodology is to apply a percentage to all production demand classified costs at the percentage necessary to make the resulting amount equal to CONE or some other measure of the value of capacity, as determined by the Commission. This would treat all costs in excess of CONE (or the Commission's chosen value of capacity) as non-capacity-related costs. Should the Commission determine such a method is more appropriate, Staff recommends that the levelized per year cost of a CT resulting from one of the rate regulated Upper Peninsula utilities' PURPA cases[5] be utilized. This would provide consistency in the Commission's determination of the value of capacity.

2 Tr 76-77.

Mr. Revere stated that the Staff further recommends that the Commission require UMERC, in its next general rate case, to file its COSS and rate design consistent with the Commission's determinations in Consumers' electric SRM case, Case No. U-18239, and DTE Electric's SRM case, Case No. U-18248, as well as the specific determinations reached in this case. 2 Tr 77. Mr. Revere further testified that Section 6w requires a single capacity charge applied to similarly-situated ROA and full-service customers, allowing for collection of class cost responsibility from that class. *Id*. With respect to the issue of how to align the collection of costs with customers' contributions to the need for capacity, he noted two difficulties. First, he stated that billing according to the measure of contribution is effectively impossible. Second, customers would not be able to determine when the peak hours would occur because they are not known until after the fact. 2 Tr 79. He suggested using a proxy such as on-peak demand, or "isolating some number of hours likely to become the [Coincident Peak] (CP) and charging each of those hours at the same rate." 2 Tr 80. He opined that for classes with large numbers of diverse customers, on-peak kilowatt hours (kWh) is the best starting point. As UMERC lacks the ability to charge most non-demand billed customers on the basis of on-peak energy, the Staff proposed "a charge based on annual kWh for the smaller [rate] schedules for which the capability to charge on an on-peak basis

[5] UPPCO, Case No. U-18094; WPS Corp, Case No. U-18095; or WEPCo, Case No. U-18096.

is lacking, and a charge based on annual on-peak energy for the smaller [rate] schedules for which [UMERC] has the ability to charge on-peak rates." 2 Tr 80-81; Exhibits S-1.2 and revised S-1.4. However, if the Commission decides that all customers must pay the same charge, then he recommends that an annual kWh charge be utilized. 2 Tr 81.

Mr. Revere testified that the Staff disagrees with UMERC's proposal to not alter its rates and tariffs for bundled customers because Section 6w(3) requires that the capacity charge apply to full-service and applicable ROA customers. *Id*. The Staff also disagrees with UMERC's proposal to reconcile all revenues and costs under the capacity charge because Section 6w requires only a very limited reconciliation of the projected net revenues used in the calculation of the SRM charge to the actual net revenues, and the difference is reflected in the charge for the next year. He noted that capacity-related costs associated with PPAs are reconciled as part of the PSCR process, and explained how the Staff proposes to deal with these costs:

> The best way to deal with potential mismatches between the amount of capacity-related costs incurred in a given year and the amount collected through the Capacity Charge is in the PSCR Reconciliation process. It would be reasonable to assume that the amount of Capacity Charge revenue associated with PPA capacity costs is proportionate to the amount of PPA capacity costs included as part of the calculation of the Capacity Charge. For example, if PPA Capacity costs are 5% of the total capacity-related costs used to calculate the Capacity Charge, 5% of the revenues received from that charge should be considered revenues to cover those same costs. Any difference between the collected revenue so calculated and the actual PPA capacity costs should be included in the calculation of the next year's Capacity Charge. This is the same treatment required for the net revenue reconciliation, and keeps the Company whole in the same manner the current PSCR reconciliation does.

2 Tr 83.

<u>Constellation NewEnergy, Inc.</u>

Laura T.W. Olive, Ph.D., Senior Consultant at National Economic Research Associates, Inc., testified on behalf of CNE that Section 6w requires LSEs to demonstrate sufficient capacity to serve all customers. Additionally, Dr. Olive testified that the law now requires incumbent regulated utilities to include the 10% choice customers in their capacity plans, and that the capacity charge will be new and incremental for ROA customers. 2 Tr 44. She stated that UMERC could have used a planning model "reflective of forward-looking capacity-only costs during the applicable term of the capacity charge, as required under Section 6w(3)." *Id*. She explained that UMERC's proposal to use the costs reflected in its PPAs with WEPCo and WPS Corp does not address the purpose of the SRM capacity charge to ensure reliability with sufficient capacity resources at forecasted peak demand. 2 Tr 45. Dr. Olive criticized UMERC's approach as reflective of only the embedded cost of service of its existing power supply agreements. 2 Tr 46. She applied the average and excess energy weighting method to calculate a single SRM capacity charge of $288/megawatt (MW)-day for both the WEPCo and WPS Corp rate zones. 2 Tr 48-49. As a check, she examined CONE for 2016 which was $260.90/MW-day and concluded that UMERC's proposal to use the capacity charges from its PPAs with WEPCo and WPS Corp is unreasonable. 2 Tr 50-51.

Lael Campbell, Director of Regulatory Affairs for Exelon, proposed that UMERC assess the SRM charge directly to the AES for the portion of AES load the Commission has determined is subject to that charge. 2 Tr 62. This permits the AES to manage capacity on behalf of customers on a portfolio basis, consistent with utility and MISO practice. *Id*. Mr. Campbell further asserts that eliminating an AES's ability to manage capacity is inconsistent with Act 341 and will result in increased costs to customers subject to the SRM. 2 Tr 63. He also stated that billing customers directly would put AESs at a competitive disadvantage compared to utilities. In contrast, when an AES manages the SRM charge on a portfolio level, it can spread the SRM cost across its load base and not discriminate against individual customers, putting the AES on equal footing with utilities.

Id. Mr. Campbell claims that Section 6w(6) explicitly states that it is the AES that pays the SRM charge. 2 Tr 64. This approach allows the AES to reduce the impact of the SRM charge on customers by blending those costs with other, potentially cheaper, assets in its capacity portfolio to meet its capacity obligations. *Id*. According to Mr. Campbell, it also makes the AES responsible for handling any regulatory disputes with the utility, sparing the customer potential litigation costs. 2 Tr 64-65.

Mr. Campbell testified that the AES would be responsible for the customers' capacity obligation with MISO for all of its load, and that the AES will have to pay the PRA clearing price for that load in each MISO annual auction. 2 Tr 65. To avoid double billing for capacity, Mr. Campbell explained that the AES would be billed the SRM capacity charge in an amount equal to the charge minus the PRA clearing price for the applicable delivery year. *Id*. According to Mr. Campbell, this approach does not deprive the utility of the full amount of the SRM capacity charge. *Id*. Mr. Campbell also identified the operational issues that exist when customers pay the capacity charge directly. 2 Tr 66.

<u>Michigan Electric Cooperative Association</u>

Thomas King Jr., Director of Regulation and Policy for Wolverine Power Supply Cooperative, Inc., described the options an AES has to procure capacity to serve its customers. He explained that an AES can either own capacity, enter into near- or long-term bilateral contracts such as PPAs, or participate in the capacity auctions of their respective regional transmission organization. 2 Tr 98. He testified that it is inappropriate to assign a capacity charge to ROA customers because, as end users of electricity, they are neither required nor able to: (1) provide information for any capacity demonstration, (2) serve their own load, or (3) own or control their own capacity. Mr. King contrasted this inability with the responsibility an LSE has to submit their capacity demonstration filings with the Commission, its obligation to serve its customers' loads, and its ability to own or control capacity resources. He therefore reasoned that an AES, as the LSE, is the proper entity that should be assessed any applicable capacity charge. He further explained that an AES customer does not decide whether to meet an AES's capacity obligation or rely on a utility for capacity as an AES does. Mr. King testified that an AES's payment of a capacity charge compensates a utility for obtaining capacity on the AES's behalf and does not involve the Commission setting capacity prices. He stated that, absent specific legislative authorization, it is fundamentally unfair from a ratemaking standpoint to assess the capacity charge on the AES customer when the customer has no say in and no ability to avoid the cost of an AES's capacity decisions. Mr. King further reasoned that the AES, as an unregulated business, would then decide if and when the cost of capacity is passed on to its customer as a "matter of private contract." 2 Tr 99.

Mr. King proposed that electric distribution companies could use their ability to charge AESs for billing services to likewise charge an AES for an applicable capacity charge. *Id*. Additionally, Mr. King testified that an AES is only responsible for paying a capacity charge after the Commission has found the AES to be deficient in its capacity demonstration. *Id*. Regarding the time period in which an AES should be assessed a capacity charge, Mr. King explained that an AES should not be required to pay a capacity charge for any year beyond the four years for which a capacity demonstration has been made. This is because there would be no evidence to support such a charge, it would be premature, and a charge would create incentives against an AES procuring its own capacity. 2 Tr 100.

Rebuttal Testimony

Upper Michigan Energy Resources Corporation

Regarding the proposal presented by MECA that a capacity charge should be assessed against an AES rather than AES customers, Mr. Derricks reiterated UMERC's proposal to bill ROA customers. Mr. Derricks explained that UMERC is not opposed to charging the AES as MECA suggested, but only if the Commission finds that it has the authority to approve and enforce such charges. 2 Tr 30. Regarding Mr. Revere's assertion that UMERC failed to properly identify its capacity-related costs that are currently included in base rates and his claim that UMERC's use of capacity rates in the two PPAs did not meet the requirements of Section 6w, Mr. Derricks disagreed reiterating his direct testimony on this issue. 2 Tr 30-31. In response to Mr. Revere's definition of capacity-related costs, Mr. Derricks explained that Mr. Revere proposed a narrower definition of that term than what Section 6w requires. He further testified that, although UMERC can accept Mr. Revere's methodology and his proposed SRM capacity charges in Exhibits S-1.2 and S-1.4 as revised, the utility reserves the right to take a different position on this issue in the future.

Regarding the Staff's proposal to charge both ROA customers and full-service customers a capacity charge, Mr. Derricks testified that he understood the Staff's proposal to be that full-service customers would continue to be charged as they have been, with no specific identification of a separate capacity charge on their monthly bill. Mr. Derricks agreed with this proposal and noted that UMERC is not proposing to change any rates for full-service customers at this time. Rather UMERC views the purpose of this docket as establishing the SRM capacity charge for AES load, rather than addressing retail rate design for its full-service customers. 2 Tr 31-32.
Mr. Derricks then provided an example illustrating how a full-service customer of a specific rate

class would be billed for capacity-related and non-capacity-related charges. He compared this to the charge that an ROA customer would have to pay if that customer's AES has not demonstrated it has sufficient capacity. His illustration showed that the full-service customer would still be charged the current energy rate, which is comprised of the same capacity charge as that billed to the ROA customer, as well as a non-capacity energy charge. 2 Tr 32.

Regarding Mr. Revere's proposal to increase the current billed demand charges for customers with demand charges, Mr. Derricks indicated that UMERC opposes this recommendation and instead proposed keeping current rates for all full-service customers. UMERC proposed applying the same methodology that Mr. Revere used for rate schedules without demand charges to identify the amount of generation capacity costs that are embedded in the on-peak energy charges for customers with demand charges in the WEPCo and the WPS Corp rate zones. Under this proposal, should an AES lack sufficient capacity, the AES or its customer would be charged the current billed demand charge and the capacity component of the on-peak energy charge. 2 Tr 33.

With respect to Mr. Revere's recommendation that the Commission require UMERC in its next general rate case to file its COSS and rate design consistent with the Commission's determinations in Case Nos. U-18239 and U-18248, Mr. Derricks responded that UMERC is unable to comment on the appropriateness of hypothetical cost-of-service methodologies or rate designs in orders that the Commission has not yet issued. 2 Tr 34. Further, regarding Mr. Revere's recommendation that the difference between projected and actual net revenues reflected in the SRM capacity charge be reconciled in the PSCR reconciliation process, UMERC supports this proposal. *Id*.

Mr. Derricks further testified that he disagrees with CNE's proposed methodology to determine SRM capacity charges, as well as CNE's proposed SRM capacity charges themselves.

2 Tr 34. However, UMERC will accept the Staff's methodology and SRM capacity charges as its initial SRM capacity charges. *Id*. He agrees with CNE that the AES would blend any SRM charge with costs from other assets in the capacity portfolio to meet its capacity obligations. He further agrees with CNE that the AES is responsible for paying the PRA clearing price for its load obligations. 2 Tr 35. He further explains that the cost for an entity to obtain capacity to meet its obligations in MISO or a state regulatory agency does not impact the PRA price that an LSE pays for its load obligations. Further, Mr. Derricks explained that an entity that has capacity and offers it into the PRA is not guaranteed to get compensation that would offset some or all of the cost of capacity to meet its planning obligations. *Id*. He likewise testified that only generation that has not cleared the PRA is available to be sold to a third party during for the current planning year. 2 Tr 36. Mr. Derricks disagreed with Dr. Olive's testimony that the AES would be double billed for capacity, so that the utility should reduce its capacity price for the sale of capacity to an AES by the PRA clearing price, because there is no direct link to what a party pays for capacity to meet its compliance obligations and the PRA price an entity pays to serve its load. *Id*.

Mr. Derricks further testified that the price risk for an AES's failure to procure capacity as the law requires is shouldered by the buyer, which is the AES. Were the utility required to reduce its price equivalent to the PRA clearing price, the AES would benefit from not procuring capacity requirements in advance, and the utility would take a reduced price it would not otherwise agree to in a third-party transaction. 2 Tr 36-37.

<u>Initial Briefs</u>

<u>Upper Michigan Energy Resources Corporation</u>

UMERC, departing from its initial proposal, accepts the Staff's methodology and proposed SRM capacity charges set forth in Exhibits S-1.2 and S-1.4 as revised. However, given its intent to construct new generation in the UP, UMERC reserves the right to propose new methodologies and/or new SRM capacity charges in the future. UMERC's initial brief, p. 16. Further, because UMERC accepts the Staff's proposed SRM capacity charges as its initial SRM capacity charges, UMERC also accepts the Staff's proposed true-up mechanism. It is a reconciliation process in which UMERC's projected net revenues described in Section 6w(3) and actual net revenues would be reconciled in the utility's annual PSCR reconciliation case, and the over- or underrecovery would be reflected in the subsequent year's capacity charges to make UMERC whole. *Id.*, pp. 16-17. UMERC further requests that the Commission authorize the utility to amend its SRM capacity charges in its annual PSCR reconciliation cases, consistent with Section 6w(5).

Regarding the effective term of the SRM capacity charge, UMERC notes that the Commission has discretion under Section 6w to determine the effective period of the charge. Based on the language of Section 6w(8)(b)(i), UMERC agrees with Mr. Stocking's testimony that, for the initial four-year demonstration period, an AES must pay the capacity charges in each of those initial four years when any portion of AES load cannot make a satisfactory capacity demonstration. *Id.*, p. 19. UMERC further agrees with Mr. Stocking's testimony that, after the initial four-year period, if the AES is able to meet its capacity obligation in a subsequent demonstration, then the AES's load would not be subject to the capacity charges. However, to make UMERC whole, the utility requests that the Commission authorize UMERC to apply SRM capacity charges to "the AES load to which the SRM capacity charges pertained in the prior planning year" to implement the true-up in the event that there is no AES load to charge the SRM capacity charges in the next planning year. UMERC's initial brief, p. 20. Further, UMERC asserts that its SRM capacity charges should remain in its tariffs in perpetuity.

UMERC is opposed to the Commission requiring a rate adjustment for any of its retail full-service customers. However, the company does not oppose identifying a capacity rate component for the existing rates of full-service customers in order to show that it has implemented Section 6w and that both its ROA customers and its full-service customers are paying the capacity costs. UMERC argues that altering its rates or specifically identifying or separating the capacity charges on the monthly bill of its full-service customers would "(i) be labor intensive; (ii) require modifications to billing systems; and (iii) potentially create unnecessary confusion for full service customers, all without serving any apparent purpose (2 Tr 32)." UMERC's initial brief, p. 21. The utility further argues that nothing in Section 6w requires UMERC to adjust rates to impose SRM capacity charges for its full service customers. Rather, the language of Section 6w(3) merely requires that the Commission "ensure that the resulting capacity charges does [sic] not differ for full service load and alternative electric supplier load." *Id*. It explains that the capacity-related costs in base rates paid by UMERC's full-service customers are based on the same COSS as the SRM capacity charges in Mr. Revere's Exhibits S-1.2 and S-1.4 as revised, so the utility will recover the same capacity costs by class from customers irrespective of whether the customer is a ROA customer or a full-service customer.

UMERC urges the Commission to reject CNE's proposed SRM capacity charges. It argues the charges do not comply with Section 6w(3)(a) because they are not based on UMERC's own base rates, surcharges, and PSCR costs but rather an external calculation. UMERC further asserts the proposal fails to allocate production costs consistent with Section 6w(3). Finally, UMERC argues that, if the Commission decides that UMERC should bill its SRM capacity charges directly to the AES, the Commission should reject CNE's proposal that UMERC bill the SRM capacity charges minus the PRA clearing price for the applicable delivery year. UMERC asserts that the harm this calculation purports to remedy, i.e., double billing, will never occur. Because UMERC will not sell any capacity into the market for which it has received SRM capacity charges, UMERC argues that no subtraction from the SRM capacity charges is necessary as the zonal resource credits would belong to the AES. *Id*., p. 23.

The Commission Staff

The Staff argues that the Commission should determine that the SRM will be in place for an "indefinite" duration and that the SRM should be effective in perpetuity, so long as Section 6w remains unchanged. Staff's initial brief, pp. 6-7. The Staff reasons that, by not setting a definite expiration date, the Commission will ensure the long-term reliability of the electric grid in Michigan thereby furthering the purpose of the statute. The Staff also explains that a limited four-year term for the SRM is insufficient for the SRM to work, as resource adequacy measures take time.

Next, in identifying capacity-related costs under Section 6w(3), the Staff recommends that the Commission only include the costs that UMERC directly incurs to supply capacity. In order to identify these costs, the Staff proposes two potential methods. In the first method, the Staff states that appropriate production costs are identified and then compared to the cost of a CT to determine capacity-related costs. If the Commission approves this method, the Staff recommends the levelized per-year costs of a CT as determined in one of the rate-regulated UP PURPA cases be utilized for this cost. *See*, the Staff's initial brief, p. 9. Under this method, the demand portion of the production allocator would be adjusted so that the capacity revenue requirement is limited to the cost of a CT unit on a megawatt year (MW/year) basis. Staff's initial brief, p. 9.

In the second method, the Staff proposes that a company's approved COSS is used to identify those costs incurred to supply capacity. Instead of adjusting a portion of the production costs as in the first method, the production allocator recognizes that only 75% of these production costs are actually incurred to provide capacity service. Recognizing that UMERC has no approved COSS that combines the service territories of WPS Corp and WEPCo, the Staff also recommends that the Commission require UMERC to file its COSS and rate design consistent with the Commission's determinations in this case in its next general rate case.

The Staff argues that UMERC's initial proposal to use the capacity charges in its PPAs is incompatible with Section 6w(3), which requires that capacity-related generation costs included in UMERC's rates be included in the capacity charge calculation. The Staff contrasts the utility's initial proposal with both of its proposed methodologies, arguing that its methodologies are compatible with the law because they align the capacity charge with capacity costs currently in the utility's rates. Further the Staff argues that, because UMERC accepts the Staff's calculations for the purposes of this case, the Commission should approve them.

In order to set a capacity charge separately for each class of customers, the Staff recommends using the results of the allocation of capacity-related costs in the Staff's COSS. The Staff interprets the law's requirement for a "single capacity charge" to mean that the charge must be the same between similarly-situated ROA and full-service customers. Thus, the Staff recommends that the same capacity charges be charged to both types of similarly-situated customers taking capacity service. The Staff agrees with UMERC's interpretation that the Staff's proposal does not require a change in UMERC's effective rates or identification of the capacity charge on the bill of full-service customers, provided that the charges are shown in the company's tariff. Further, for demand-billed customers whose current demand charge is lower than the calculated capacity demand charge, the Staff disagrees with UMERC's proposal to split the capacity charge into a demand piece that would not exceed the current power supply demand charge, and an on-peak energy piece that would make up the difference. According to the Staff, this proposal does not meet the law's requirement of a single capacity charge. *Id*., p. 12.

The Staff proposes that the capacity charge be based on annual kWh for non-demand billed customers for whom UMERC lacks the ability to charge based on on-peak kWh. For those customers who can be billed on-peak, the Staff recommends that the Commission approve on-peak kWh capacity charges. The Staff explains that, applying a charge to the highest hour of demand the customer places on the system during the on-peak hours of a billing month, recognizes that each of those on-peak hours has some chance of being the CP, and charges on that basis. *Id*., p. 13; 2 Tr 79. For classes with large numbers of smaller customers, the Staff recommends selecting some series of hours likely to become CP and billing based on those hours. Staff's initial brief, p. 13. The Staff asserts that this spreads the cost responsibility over all hours that could potentially become CP. The Staff recommends on-peak kWh because this proposal sends an effective price signal and does not shift the peak such that the rate no longer reflects the hours likely to become a CP. *Id*.; 2 Tr 80. Further, if the Commission were to interpret the law as requiring one capacity charge that applies to all customers, then the Staff recommends that the charge be levied based on annual total kWh, as the "result should be similar for the larger customers, and more accurate for the smaller." Staff's initial brief, p. 14; 2 Tr 81.

The Staff further recommends that the Commission approve the reconciliation required by Section 6w(4). The Staff explains that this reconciliation is limited to the revenues and costs required by Section 6w(3)(b), which includes: all energy market sales, off-system energy sales, ancillary services sales, and energy sales under unit-specific bilateral contracts. The Staff explains that the revenues UMERC actually received in these four categories, net of the fuel costs incurred in their production, would be reconciled with the projected net revenues included in the calculation of the capacity charge in the year in question. Any difference would be included in the calculation of the next year's capacity charge. In addition, because capacity-related costs associated with PPAs are currently reconciled in the PSCR process, the Staff explains that the best way to deal with differences between capacity-related PSCR costs is in the PSCR reconciliation process. Staff's initial brief, p. 14; 2 Tr 83. The Staff finds it reasonable to assume that the amount of the capacity charge revenue associated with PPA costs is proportionate to the amount of PPA costs included as part of the capacity charge, and that the difference, if any, between the revenue collected and the actual PPA capacity costs, should be included when calculating the following year's capacity charge. Staff's initial brief, pp. 14-15. The Staff argues that the Commission should reject UMERC's proposal of a reconciliation of all capacity-charge revenues and costs because this is not what the law requires. Staff's initial brief, p. 15.

<u>Michigan Electric Cooperative Association</u>

MECA argues that the Commission should determine the SRM capacity charge must be charged to the LSE and not the customer, arguing that basic principles of cost causation and rate design require this result. MECA's initial brief, p. 6. MECA explains that LSEs are responsible for serving their customers, including providing needed capacity, and filing a capacity demonstration with the Commission. In contrast, MECA points out that customers, as the end users of electricity, are not required or able to: (1) provide information for a capacity demonstration, (2) serve their own load; or (3) own or control their own capacity "destiny." MECA's initial brief, p. 6. MECA further reasons that an LSE's failure to meet its own capacity obligations should not result in an unavoidable direct capacity charge on customers. MECA also points out that an AES makes the decision whether to meet its capacity obligation or rely on a utility for the capacity. MECA further asserts that the utility that provides capacity to meet the

AES's capacity obligation provides a service to the AES. Under this reasoning, MECA argues that it is appropriate for the AES to compensate the utility by paying the capacity charge.

MECA further argues that, in Section 6w(6), the Legislature placed the obligation for both the capacity demonstration and the capacity charge on AESs, rather than on their customers. According to MECA, Section 6w assigns to the incumbent utility the responsibility to act as the provider of last resort with respect to the capacity obligations of AESs in its territory. This means that UMERC may have to provide additional capacity, beyond what it presents in its capacity demonstration, as a result of the SRM obligation.

MECA takes issue with UMERC's "erroneous" assumption that the choice customer will pay for capacity. According to MECA, customers pay for service and not capacity, and, therefore, customers have no ownership interests or entitlement in the capacity dedicated to serving them. MECA explains that this flawed assumption is avoided when the AES is required to pay the utility the capacity charge for the portion of the capacity the utility provides.

Because UMERC does not oppose an approach where the Commission requires the AES to pay the SRM capacity charge, MECA argues that the Commission should ensure that such an approach is adopted in all Section 6w SRM capacity charge cases. MECA views the SRM capacity charge to be a compensatory charge paid by a capacity-short AES to UMERC to make UMERC whole for its own wholesale capacity costs. It envisions this charge as first being determined in each LSE's individual SRM case and then set forth in the utility's ROA tariff's retailer section. The tariff would establish an agreement requiring a capacity-short AES to pay a retail capacity charge as one of the terms and conditions the AES must satisfy to provide service to the utility's ROA customers. MECA asserts that imposing a capacity charge on customers rather than the AES will only "quash Choice by deterring incumbent utility customers from leaving those utilities for an AES." MECA's initial brief, p. 11. MECA also argues that discouraging electric choice does not improve energy reliability in Michigan and is not consistent with Act 341.

Regarding the term or duration of the SRM capacity charge, MECA claims that there is no evidence to support a finding that a capacity charge can be required for future years beyond the initial four years, where there are no requirements to determine whether an LSE has sufficient capacity for any year. MECA asserts that an AES who is required to pay a capacity charge for an excessive period of time has no incentive to procure its own capacity. Therefore, MECA argues that a 30-year payment obligation is unnecessary, inconsistent with Act 341, and appears to be designed to do nothing other than stifle competition and crush electric choice. Rather, to comply with Section 6w, the Commission should instead conclude that capacity charges for capacity-short AESs should only be imposed for the initial four-year term, then for one year at a time. MECA also opposes a locational requirement.

Constellation NewEnergy, Inc.

CNE argues that the Commission should reject UMERC's proposed SRM capacity charge as it does not reflect UMERC's costs to provide SRM capacity service. CNE criticizes UMERC's initial methodology for calculating its SRM charge because it does not comply with Act 341. Using the National Association of Regulatory Utility Commissioners' (NARUC) established "average and excess" energy weighting method, Dr. Olive derived an appropriate SRM charge for UMERC of $288/MW-day. CNE's initial brief, p. 7. However, because CONE is the highest amount any participant in the MISO capacity market would have to pay for capacity, CNE recommends that the Commission adopt an SRM charge for UMERC no higher than MISO's CONE for Zone 2, which was set at $260.90/MW-day for the 2017-2018 planning year. CNE's initial brief, p. 8. CNE further asserts that the Commission should direct UMERC to assess the

SRM capacity charge on the AES as Act 341 requires, rather than on the AES customer. The company identifies several pitfalls that would result from directly charging AES customers for the SRM capacity charge. These include: diminished benefits of participating in the ROA program, placing customers in the center of disputes relating to the AES's capacity demonstration, operational issues, and issues regarding terms of retail contracts and who has responsibility for a particular customer's capacity at MISO. CNE's initial brief, pp. 9-10. If necessary, CNE points out that an AES customer could opt-in or consent to allowing the utility to bill their AES directly for the SRM capacity charge.

Verso Corporation

Verso opposes UMERC's initial proposal to base the SRM capacity charge on the capacity formula rates used in its PPAs with WEPCo and WPS Corp. First, it argues that this proposal is inconsistent with Michigan's cost-of-service ratemaking principles because the PPAs were entered into in order to serve non-ROA load. This approach is therefore not the appropriate measure for costs imposed by the ROA customer class. Second, UMERC's initial proposed capacity charge appears to significantly exceed the costs of available capacity on the MISO market, capped at CONE. Third, UMERC has not presented testimony that its proposed charge contains only capacity-related generation costs. Verso also agrees with CNE's and the Staff's argument that the proposal is inconsistent with Section 6w because it does not address or identify which charges are specific to capacity only. Verso likewise agrees with testimony presented on behalf of CNE that there is "nothing forward-looking, planning-based, or market-based" about UMERC's proposed capacity charge and that it "reflects only the embedded cost of service" of those agreements. Verso's initial brief, p. 9. Verso explains that the charge is inconsistent with Section 6w and

MCL 460.11 because it fails to demonstrate that the rate reflects actual costs imposed to obtain only capacity for ROA load. Instead, Verso argues that the proper method of calculation of the capacity charge is CONE. Verso explains that use of CONE is consistent with the goals of Section 6w.

Verso further maintains that the AES must manage and pay the SRM capacity charge because this is consistent with the language of Section 6w(6) as well as MISO's tariff. Verso's initial brief, p. 10. Making the AES customer responsible for the charge is inappropriate, Verso argues, because the customer cannot control capacity and would be placed in the middle of disputes about capacity, bearing the brunt of the financial costs while lacking the ability to affect the result. In contrast, if the AES pays the charge, it can continue to bill customers according to the contract it has with the customer, which may or may not include payment of an SRM charge. The AES would have the choice to spread the capacity cost across its load base and would give the AES the opportunity to remove any potential discriminatory impact on individual customers. Likewise, Verso maintains that Section 6w(6) specifically requires the AES, and not the AES customer, to pay the SRM capacity charge.

Last, Verso asserts that the term of the SRM capacity charge should be year-to-year beginning with planning year 2018. It is inconsistent with Section 6w to require an AES to pay the SRM capacity charge during a year it has sufficient capacity and would result in a windfall to the incumbent utility that would be collecting a charge without providing any service to the AES. This would also violate state cost-of-service principles. Verso explains that billing only for the applicable delivery year does not deprive UMERC of the full SRM charge.

Verso disagrees with the Staff's interpretation that Section 6w(8)(b)(i) provides an exception to the requirement that an SRM capacity charge may only be assessed onto AES load for years in which the AES is unable to provide a satisfactory capacity showing before the Commission. A conclusion that an AES must pay the capacity charge in each of the initial four years when it fails to make the requisite capacity demonstration in any one of those years is, according to Verso, inconsistent with Section 6w(6), which restricts the assessment of the charge to only those years in which the AES cannot demonstrate sufficient capacity.

Reply Briefs

Upper Michigan Energy Resources Corporation

UMERC reiterates that it supports the Staff's second method to identify capacity costs in the most-recently approved COSS for WEPCo and WPS Corp and then apply a production allocator recognizing that only 75% of these costs are actually incurred to provide capacity service, as calculated and set forth in the Staff's Exhibits S-1.2 and S-1.4 as revised. It again reiterates that, because it will construct new generation in the UP, it reserves the right to propose new methodologies and/or new SRM capacity charges in the future. UMERC's reply brief, p. 2.

In response to the Staff's recommendation that the SRM capacity charges approved in this case be charged to both full-service customers and similarly-situated ROA customers receiving capacity service, UMERC disagrees with the Staff's position that the charges must be shown in the tariff because this would result in a disconnect between tariffed rates and billed charges that would confuse customers. UMERC further disagrees with the Staff's position that UMERC's proposal (to split the charge into a demand piece and an on-peak energy piece for demand-billed customers whose current demand charge is lower than the capacity charge demand charge) does not meet Section 6w's requirement of a single capacity charge. UMERC states that altering its rates in this case or identifying or including separate charges on the monthly bill of full-service customers would unnecessarily confuse customers, be labor intensive, and require modifications to the utility's billing system, all without serving any purpose. *Id*., p. 4. UMERC points out that the Staff fails to cite language from Section 6w that requires it to adjust its rates for full-service customers. UMERC reiterates that it supports the Staff's true-up mechanism.

UMERC agrees to charge the AES directly if the Commission makes such a determination. *Id*., p. 5. UMERC further argues that the Commission should reject CNE's and Verso's SRM capacity charge proposals because they do not comply with Section 6w(3). Specifically, UMERC contends that CNE has not shown and cannot show that basing UMERC's capacity charges on CONE meets the requirement of Section 6w(3)(a) that charges be based on the utility's capacity-related generation costs included in its base rates, surcharges, and PSCR factors. It also does not show that the method "would not result in UMERC's full requirements service customers bearing a disproportionate share of the capacity costs." *Id*., p. 6. Nor does it show that UMERC would be made whole for ensuring capacity to the AES's customers.

Regarding the planning years to which the SRM capacity charge applies, UMERC reiterates its agreement with the Staff that, for the initial four-year capacity demonstration, any portion of AES load that cannot make a capacity demonstration would require payment of the SRM capacity charges in each year of the initial four-year period. *Id*., p. 7. And, UMERC further agrees with the Staff that, after the initial four-year period, the requirement to pay the SRM capacity charge is determined on an individual planning year basis. UMERC contends that the Commission should reject Verso's position on this issue because it is contrary to the statutory language of Section 6w(8)(b)(i), which requires that the charge be paid for all of the years in the initial four-year period. *Id*. UMERC argues that this provision controls over Section 6w(6) because it is the more specific of the two. UMERC further argues that the word "each" in that provision is synonymous with the word "all." *Id*., p. 8. UMERC also disagrees that this would result in a windfall to the utility as UMERC would not be able to sell the capacity into the PRA.

Regarding MECA's arguments about a locational requirement, UMERC points out that this issue will not be decided in this docket.

The Commission Staff

Although the Staff agrees with Verso that the FERC-approved capacity formula rates in UMERC's two PPAs with WEPCo and WPS Corp. should not serve as the SRM capacity charge in this docket, the Staff disagrees with the reasoning offered by Verso because it is based on the incorrect assumption that ROA customers comprise a separate class. The Staff also disagrees with Verso's position that basing the capacity charge on embedded costs is inconsistent with Section 6w and MCL 460.11. The Staff argues that the charge must be based on the utility's embedded costs in order to comport with Section 6w, as those costs are included in rates. The Staff urges the Commission to reject Verso's proposal.

In response to MECA, the Staff takes issue with any assertion that paying a rate based on embedded capacity would lead to some ownership over the capacity, asserting that MECA's concern is misplaced.

With respect to CNE's endorsement of the average and excess method to identify capacity costs, the Staff urges the Commission to reject this proposal, responding that the Staff's proposal is simpler, easier to implement, and more reflective of the utility's costs. The Staff further disagrees with CNE's recommendation that the SRM capacity charge be capped at CONE. It argues that setting such a cap is arbitrary, unnecessary, and inconsistent with Section 6w, which does not provide for any particular cap on otherwise includable capacity-related generation costs.

Next, the Staff asserts that the Commission should decide whether UMERC should charge their ROA customers directly or charge the AES the SRM capacity charge. The Staff explains that, read as a whole, Section 6w requires that the ROA customer pay the charge. Staff's reply brief, p. 5. Several subsections within Section 6w refer to AES "load," rather than "AES," which the Staff interprets to mean that it is the ROA customer who must ultimately be billed for the charge. The Staff argues that CNE's interpretation ignores the practicalities of the statute and the obligation it imposes. In addition to imposing a charge, the Staff explains that Section 6w imposes the obligation on incumbent utilities to provide a service to their ROA customers, and it would be illogical to bill the AES for a service that the utility provides directly to its ROA customers. *Id*., pp. 5-6.

The Staff further argues that CNE's position advocating billing AESs directly would render nugatory that portion of Section 6w that requires that the Commission must ensure the charge paid by full-service load and AES load does not differ. Further, the Legislature would not have ordered the Commission to set a wholesale rate when it knows that the Federal Power Act (FPA), 16 USC 791 *et seq*., does not permit the Commission to do so and would preempt such legislation and frustrate its purpose. Accordingly, the Staff argues that the Legislature must have intended that the Commission set a retail rate, consistent with the entirety of Section 6w. The Staff further disagrees with CNE's argument that directly billing ROA customers prevents AESs from managing capacity on a portfolio basis, because AESs could incorporate provisions into their contracts with customers that would achieve the same results even when customers are directly billed for the capacity service the utility provides.

Michigan Electric Cooperative Association

MECA repeats its position that the Commission should make clear the charge may only be assessed upon the AES and not the choice customer. It again quotes the language in Section 6w(6) that references the electric provider as the entity that may expect to pay a capacity charge in support of its position. It again argues that, because customers are neither required nor able to provide information for a capacity demonstration, serve their own load, or own or control their own capacity destiny, they are not the appropriate party upon which to levy the charge. Further, because the decision to meet its capacity obligation or rely on a utility is one the AES makes, the AES must compensate the utility by paying the capacity charge. MECA's reply brief, p. 2. MECA further argues that the reference to "load" in Section 6w means "AES load" rather than "individual customer load." *Id*., p. 3. Finally, MECA states that the Legislature did not give the Commission the authority to impose the charge on choice customers, and it would be improper and unlawful to do so. Thus, it asks that the Commission's order provide that AESs, not choice customers, must pay the capacity charge for only the capacity demonstration time horizon and establish the SRM capacity charge while not imposing a locational requirement.

Constellation NewEnergy, Inc.

CNE reiterates that the Commission should adopt an SRM charge for UMERC no higher than MISO's CONE for Zone 2, which was set at $260.90/MW-day for the 2017-2018 planning year. It argues that UMERC's proposed charge should be rejected. CNE disagrees with UMERC's assertion that it used an external calculation to arrive at an SRM capacity charge, arguing that Dr. Olive used UMERC's own embedded cost data to derive the charge.

CNE again argues that the Commission should direct UMERC to assess the capacity charge on the AES, as Act 341 requires, instead of on the AES customer. CNE points out that the Staff never addresses its argument that Section 6w(6) indicates that it is the electric provider that pays the capacity charge.

CNE further requests that the Commission reject UMERC's proposal to amend its SRM charge in its PSCR reconciliation proceeding. CNE instead recommends that the Commission open a standalone docket each year for the purpose of setting the SRM capacity charge so as to avoid making PSCR reconciliation proceedings even more complex than they already are. CNE also argues that PSCR proceedings are the wrong forum for adjusting general rates to ensure that the capacity charges for bundled service customers and AES customers are the same.

CNE also requests that the Commission defer ruling on any SRM true-up mechanism because such issues are not yet ripe for Commission review. According to CNE, it would be inappropriate and premature for the Commission to render an advisory opinion on how future SRM charges should be trued-up based on unknown future facts.

<u>Discussion</u>

<u>The Term of the State Reliability Mechanism and the Capacity Charge</u>

Regarding the term of the SRM, the Commission agrees with the Staff and UMERC that the SRM continues in perpetuity. The Legislature, in its wisdom, crafted Section 6w to give the Commission a tool for better ensuring the reliability of electric supply for Michigan's electric service ratepayers over the long term. Section 6w(1) and (2) indicate the flow of options for providing this tool, beginning with the potential approval by the FERC of an ISO's resource adequacy tariff that provides for a capacity forward auction, moving to approval of a PSCM, and then, in default of either of those options occurring, examination of an SRM. The latter describes the situation in Michigan. *See,* n. 1, *supra.*

Section 6w(2) provides that "[i]f, by September 30, 2017, [the FERC] does not put into effect a resource adequacy tariff that includes a capacity forward auction or a prevailing state compensation mechanism, then the commission shall establish a state reliability mechanism under subsection (8). . . . If the commission implements a state reliability mechanism, it shall be for a minimum of 4 consecutive planning years beginning in the upcoming planning year;" and Section 6w(3) provides that "[a]fter [April 20, 2017], the commission shall establish a capacity charge as provided in this section." The first quoted sentence indicates that the Commission "shall" establish an SRM, and the last quoted sentence indicates that the Commission "shall" establish a capacity charge. The fact that the intervening quoted sentence begins with "if" does not persuade the Commission that the SRM is meant to be optional – it is, after all, a mechanism. The mechanism may not result in the shifting of a capacity obligation from an AES to an incumbent utility every year, but that does not mean the mechanism itself ceases to exist, or there is no need for the mechanism to continue in perpetuity in order to ensure adequate electric supplies over the long term. The mechanism will continue to be a tool at the Commission's disposal until amendment or repeal of Section 6w. The Staff correctly observes that any statute that does not have an automatic expiration date or sunset provision continues in perpetuity until it is amended or repealed by the Legislature alone. No administrative agency may amend or repeal a statute.

The Commission finds that Section 6w does not limit the term that a charge may remain in place, with the exception of the language just quoted providing that "[i]f the commission implements a state reliability mechanism, it shall be for a minimum of 4 consecutive planning years beginning in the upcoming planning year." MCL 460.6w(2). When this language is read in conjunction with the requirement under Section 6w(8)(b)(i) that "[i]f a capacity charge is required to be paid under this subdivision in the planning year beginning June 1, 2018 or any of the 3 subsequent planning years, the capacity charge is applicable for each of those planning years," the Commission concludes that the Legislature intended for the first four consecutive planning years to be treated as a group and that any capacity charge applicable to any of those first four planning years is also applicable to every other year in the first four planning years.

Other than this limitation applicable to the first four planning years, Section 6w provides no other indication as to the required term of the capacity charge. Verso argues that a term longer than a year would violate the language of Section 6w(6) which states that a "capacity charge shall not be assessed for any portion of capacity obligations for each planning year for which an [AES] can demonstrate that it can meet its capacity obligations." The Commission disagrees. This sentence makes clear that a charge shall not be assessed <u>for</u> a planning year for which an AES can make its demonstration, but it does not say that a charge may not be assessed <u>in</u> a planning year for which an AES can make its demonstration. The Commission therefore concludes that Section 6w allows for a charge to be assessed in a planning year different from the planning year for which the AES failed to show sufficient capacity and for which the utility may recover capacity costs from ROA customers.

That said, the statute thereafter focuses on one year at a time, where it requires that "each year" electric utilities, AESs, cooperatives, and municipally-owned utilities shall make their demonstrations "for the planning year beginning 4 years after the beginning of the current planning year." MCL 460.6w(8)(a) and (b). In this context, and bearing in mind that this is the first group of cases setting a capacity charge, the Commission finds that the charge (with the exception of the first four consecutive planning years) should be imposed on an annual basis for a single year. This ensures that the capacity charge comports with the requirements of the statute while avoiding imposition of the charge on the initial group of ROA customers for a term that is unduly burdensome.

The Commission finds that the initial capacity charge that is levied on choice customers at the conclusion of a show cause proceeding for planning years 2018-2021 shall be for the first four consecutive planning years, and any charge levied thereafter at the conclusion of a show cause proceeding shall be levied and applicable for a single year.

The Method for Determining the Capacity Charge

The record in this matter includes a wide range of competing proposals, with differences among the proposals broad enough to make each comparison apples to oranges. Moreover, some areas of analysis are highly conceptual but lack sufficient details and mechanics to actually allow for implementation. Fortunately, the statute provides significant guidance in Section 6w(3)(a), where it instructs the Commission to begin the calculation of the charge by including "the capacity-related generation costs included in the utility's base rates, surcharges, and [PSCR] factors," regardless of whether those costs result from owned, purchased, or leased resources. The Commission therefore finds that, based on the record in this case, it is reasonable to begin with embedded costs contained in the full portfolio of resources.

For the Staff's second proposed method to determine the charge, the Staff went through the COSSs the Commission most recently approved for WEPCO and WPS Corp. and identified those costs that are capacity related by identifying costs currently classified as production-demand related and excluding those costs not directly incurred to provide capacity service. 2 Tr 76. These COSSs are used to calculate the rates that UMERC currently charges. The results of the Staff's capacity-related cost identification are shown on Exhibits S-1.1 and S-1.3. To these identified costs, the Staff next applies the production allocator, which effectively recognizes that only 75%

of these costs are incurred to provide capacity service. *See*, Staff's initial brief, pp. 9-10; Staff's Exhibits S-1.2 and S-1.4 as revised. The Staff further recommends that the results of the allocation of capacity-related costs in the COSSs be used to set a capacity charge separately for each class of customers.

Given the record before the Commission in this proceeding, the Staff and UMERC's agreement on the Staff's second proposed method for calculating the SRM capacity charge, and the absence of a better alternative that is reflective of the utility's embedded costs, the Commission finds the Staff's second proposed method of calculating the capacity charge set forth in Exhibits S-1.2 and S-1.4, as revised, to be a reasonable method under Section 6w(3)(a) for the purpose of reaching a decision on the SRM capacity charge by the statutory deadline of December 1, 2017. The Commission is cognizant that this decision is a departure from its previous decisions in Consumers' electric SRM case, Case No. U-18239, and DTE Electric's SRM case, Case No. U-18248. However, the Commission must base its decision on the evidentiary record before it and is constrained by the testimony, exhibits, arguments, facts, and circumstances presented in this case. The parties should not conclude from the Commission's decision on this issue that this approach is the preferred method going forward. Rather, in UMERC's next Section 6w(5) review case, the company shall present applicable forecasted offset amounts as required under Section 6w(3)(b), in order for the Commission to more closely align the method for calculating the charge to that approved in Case Nos. U-18239 and U-18248. *See*, November 21, 2017 order in Case Nos. U-18239, pp. 65-68, and U-18248, pp. 66-69. The Commission also recognizes that UMERC is building new generation to replace the PPAs and this may affect the cost of capacity and resulting SRM charges in the future. Further, the Commission agrees with and adopts the Staff's recommendation that UMERC, in its next general rate case, file its COSS and rate design consistent with the Commission's determinations in Case Nos. U-18239 and U-18248, as well as the specific determinations reached in this case.

Rate Design

The Commission agrees with the Staff that the results of the allocation of capacity-related costs in the COSS should be used to set a separate charge for each customer class, and that the SRM charge should not result in alteration of the spread of the total revenue requirement among rate classes. The Commission therefore adopts the Staff's rate design proposal as set forth in Exhibit S-1.4, as revised. The Commission concludes that demand billed customers shall have rates based on demand charges. Because UMERC lacks the ability to charge most non-demand billed customers on the basis of on-peak energy, the Commission agrees with and adopts the Staff's proposal of a charge based on annual kWh for the smaller schedules for which the capacity to charge on an on-peak basis is lacking, and a charge based on annual on-peak energy for the smaller schedules for which UMERC has the ability to charge on-peak rates. In addition, the Commission approves UMERC's request, which the Staff agreed to, that the utility not be required to identify the capacity charge on the utility bill for its full-service customers. Further, the Commission adopts the Staff's proposal that the capacity charge be identified in the utility's tariff. The Commission anticipates that the potential for customer confusion can be avoided by clarifying discrepancies between billed rates and tariffed rates in the tariff itself. Because the Commission is adopting the Staff's rate design proposal of a single capacity charge, the Commission rejects UMERC's request to split the charge into two pieces that include an on-peak energy piece and a demand piece for the utility's demand-billed customers whose current demand charge is lower than the calculated capacity demand charge. Instead, the resulting tariff will identify a power supply capacity demand charge as the Staff has recommended.

Section 6w(3) provides that no new capacity charge may be required to be paid before June 1, 2018. The Commission finds that the capacity charge approved by this order shall apply to bundled customers as of that date. Attachment A to this order reflects the application of the decisions made herein to the Staff's proposed rate design, and Attachment B (which is not physically attached to the order) contains the revised tariff sheets. Tariff sheets substantially similar to Attachments A and B shall be filed before June 1, 2018.

Section 6w(4) provides for a true-up of "the difference between the projected net revenues described in subsection (3) and the actual net revenues reflected in the capacity charge." Projected net revenues are addressed in Section 6w(3)(b). Thus, the Commission agrees with the parties that the reconciliation required under Section 6w(4) is limited to the amounts forecasted under Section 6w(3)(b) and should occur in the annual PSCR reconciliation – a currently-existing proceeding that is designed for this precise type of true-up and which already calls for the filing of much of the relevant information in that docket, since fuel costs, market revenues, sales, and PPA expenses are reconciled in PSCR cases. Any difference will be included in the following year's capacity charge. The Commission does not find, at this time, that the creation of a standalone proceeding is necessary. Among the options of general rate cases (which require a decision within ten months), PSCR plan cases, and PSCR reconciliations, the Commission believes that the annual review of the SRM charge required under Section 6w(5) will be accomplished for UMERC. If, after more experience with implementation of Section 6w, the Commission finds it necessary, the question of a separate proceeding even in years when a rate case and a PSCR reconciliation are taking place may be revisited. In the meantime, the Commission finds that a standalone proceeding need only be commenced if no annual review will take place in a rate case or PSCR case. Accordingly, the

Commission agrees with UMERC that its SRM charge may be amended in its PSCR reconciliation.

Application of the Capacity Charge to Choice Customers

Several intervenors argue that the capacity charge should be levied on the AES and not on choice customers. The Commission finds that a capacity charge shall be levied on the ROA customer receiving the capacity service from the incumbent utility for several reasons. As these intervenors are well aware, Section 201(b)(1) of the FPA, 16 USC § 824(b)(1), vests the FERC with jurisdiction over wholesale sales of electric energy in interstate commerce; and Section 205(a) of the FPA, 16 USC § 824d(a), confers on the FERC the responsibility to ensure that wholesale power sales rates and charges are just and reasonable. *See*, *Mississippi Power & Light Co v Mississippi ex rel Moore*, 487 US 354, 371; 108 S Ct 2428; 101 L Ed 2d 322 (1988). AESs resell their product to ROA customers. Thus, were the Commission to, pursuant to Section 6w, set a capacity charge to be paid by AESs to incumbent utilities, Section 6w would be a legal nullity subject to immediate federal preemption. The Commission finds it disingenuous to posit that the Legislature mistakenly engaged in the pointless enactment of a statute requiring the Commission to set a wholesale rate for AESs, when other aspects of Section 6w reveal that the Legislature well understood the role that the FERC plays in the MISO process.

Rules of statutory construction provide that the "words used in the statute are the most reliable indicator of the Legislature's intent and should be interpreted on the basis of their ordinary meaning and the context within which they are used." *Dep't of Environmental Quality v Worth Twp*, 491 Mich 227, 237-238; 814 NW2d 646 (2012). Effect should be given to every phrase, clause, and word in the statute "read and understood in its grammatical context," and the statute "must be read as a whole unless something different was clearly intended." *Id.* The Commission "must give effect to every word, phrase, and clause in a statute and avoid an interpretation that would render any part of the statute surplusage or nugatory." *Johnson v Recca*, 492 Mich 169, 177; 821 NW2d 520 (2012). Clearly, this concept extends to an entire statute. The Commission has no jurisdiction over wholesale power sales – a fact that the Commission feels justified in believing the Legislature to be aware of.

As the rules of statutory construction make clear, the words used in the statute are the most reliable indicator of the intended meaning. The specific language of Section 6w is instructive. Everywhere that the charge is referred to, the Commission is instructed to apply it to full-service or AES "load." Section 6w(3) provides "the capacity charge must be applied to alternative electric load," and the Commission "shall . . . ensure that the resulting capacity charge does not differ for full service load and alternative electric load." Section 6w(6) provides that the charge "must be paid for the portion of [the utility's] load taking service from the [AES] not covered by capacity." Section 6w(7) provides that the incumbent utility "shall provide capacity to meet the capacity obligation for the portion of that load taking service from an [AES]." And, Section 6w(8)(b)(i) provides that the Commission shall, "[f]or alternative electric load, require the payment of a capacity charge that is determined, assessed, and applied in the same manner as under subsection (3) for that portion of the load not covered as set forth" in subsections (6) and (7).

"Load" can be ambiguous but is generally understood to mean power consumed, as by a device or circuit.[6] "To different people in different departments of a utility, load may mean different things; such as active power (in kW), apparent power (in kVA), energy (in kWh), current (in ampere), voltage (in volt), and even resistance (in ohm). In load forecasting, load usually

[6] *Webster's Third New International Dictionary* (1st ed).

refers to demand (in kW) or energy (in kWh)."[7] What each of these definitions has in common is that they relate to the use of power by the end-user. In addition to Section 6w, "load" is frequently referred to in the choice law, 2001 PA 141 (Act 141), MCL 460.10 et seq., as well. For example, Section 10a(1)(b) of Act 141 requires the Commission to "allocate the amount of load that will be allowed to be served by alternative electric suppliers;" and Section 10bb(3) provides that "'aggregation' means the combining of electric loads of multiple retail customers or a single customer with multiple sites." It is important to remember that the capacity charge is paid by both full-service and choice customers. Each use of "load" in both the choice law and in Section 6w refers to power that is consumed by end-users and could often be replaced with the word "customers;" but none of these references to "load" make sense when replaced with "alternative electric supplier." Nothing may be read into a statute that is not "within the manifest intent of the Legislature as derived from the words of the statute itself." *Covenant Medical Ctr v State Farm Mut Automobile Ins Co,* 500 Mich 191, ___; 895 NW2d 490, 495 (2017) (citation omitted). The Commission finds that to levy the capacity charge on an AES would require reading into Section 6w something that is not there.

In making their argument, the intervenors emphasize the wording of Section 6w(6), which requires an "electric provider" that has previously made a satisfactory demonstration to give notice to the Commission if it expects to be unable to make its demonstration in the next (four-year-out) planning year "and instead expects to pay a capacity charge." The Commission finds that this sentence must be read in the context of Section 6w as a whole. *Johnson,* 492 Mich at 177. There is no entity that could give such notice other than the AES, since only the AES knows whether it

[7] Hong, T., *et al*, Load Forecasting Case Study, January 15, 2015, NARUC and Eastern Interconnection States' Planning Council, p. 9-2.

intends to provide its customers with sufficient capacity or intends to provide something less. ROA customers are incapable of providing such notice, even though they are the parties that will be paying the charge.

The Legislature has chosen to make incumbent utilities (which are subject to rate regulation) the capacity suppliers of last resort under Section 6w(7). The capacity charge is a retail rate, designed to recover the incumbent utility's cost of providing capacity service, to whatever type of customer load–bundled or choice. The Commission has full discretionary authority to set just and reasonable rates, which are based on a determination of the reasonable costs of doing business and what charges and expenses to allow as costs of operation. MCL 460.6; *Detroit Edison Co v Public Service Comm,* 127 Mich App 499, 524; 342 NW2d 273 (1983). The service is provided by the utility, and thus must be billed by the utility. And, this service to provide long-term resource adequacy as a default provider is essential to ensuring reliable electric service for all customers. *See*, MCL 460.10(a), (c). AESs remain free to contract with their customers in whatever way they wish to mitigate the effect of the capacity charge, when capacity must be supplied by the incumbent utility because the AES has failed to make a satisfactory demonstration. And, the Staff correctly points out that if the service were billed to the AES, there would be no way for the Commission to carry out the mandate that the capacity charge paid by bundled load and choice load must not differ, nor any way for the Commission to ensure that the cost to the customer reflects the cost to serve that customer under MCL 460.11.

Finally, the Commission wishes to elaborate on how Section 6w and the choice law are intended to work together. In the two decades since varying forms of retail competition were implemented in states across the country, different models for continued state oversight over the supply and delivery of electricity have emerged. Provision of electricity to end-use customers is comprised of multiple components, including power supply service (e.g., energy and capacity), wires service (e.g., distribution), and other functions associated with the use of electricity, such as energy efficiency programs, providing bill payment assistance to low-income customers, and collection of funds to use for decommissioning of nuclear generating facilities. Even with the advent of retail competition, many states continued to set prices for "default" electricity service, to ensure the availability of reliable power to end-users and meet other objectives including, in some cases, state policy goals. Under Act 141, Michigan left this default service responsibility with the incumbent utility, and the Commission retained jurisdiction to regulate the utility's rates for electric generation services. The regulated utility was expected to compete with the licensed AESs in the provision of power supply service while at the same time providing wires service, as well as functions like energy efficiency programs, to all end-use customers. In other states with restructured electricity markets, default power supply services were provided by either the incumbent utility or another entity selected through a competitive bidding process or other mechanism. Some states that required the incumbent utility to fully divest its generation as a competitive function still facilitated and approved procurement activities for energy or capacity to reliably serve some or all end-use customers under their retail choice model (or the transition thereto).

The purchase of energy, capacity, or both, from a third party by the LSE, whether it is a vertically integrated utility under state rate regulation or a competitive retailer or default service provider under a retail choice construct, is a wholesale purchase. But charging customers for the provision of electricity supply and other services associated with customers' electricity use is decidedly a retail activity. States have defined what types of entities provide these services with varying degrees of specificity. In some states, it is only the regulated incumbent utility providing power supply, wires service, and other functions, costs for which are recovered through retail rates. In states with retail competition, some of these services, such as power supply, are provided by a third party under market-based prices, or as part of regulated default service, with the wires and other functions associated with electricity use collected through nonbypassable charges flowing through to the customer (either directly or in combination with the energy supply portion).

The provision of power supply service includes both capacity and energy components, among others. Providing long-term "capacity service" to customers to ensure future resource adequacy and provide reasonable assurance that energy will be actually available at any given moment (particularly peak periods) is related to, but notably distinct from, supplying only "energy." These two products or services – energy and capacity – are distinguished from one another in many wholesale contractual arrangements, such as PPAs and in long-term resource planning. They are measured differently as well – kW versus kWh. The costs to provide capacity and energy are allocated to, and collected from, end-use customers differently through conventional cost allocation and rate design methodologies. And, like other services, such as energy efficiency costs which are recovered through nonbypassable retail charges assessed to end-use customers, the capacity charge under Section 6w is set by the state as a retail charge assessed to retail customers. This is an acknowledgement that Section 6w creates a new category of default service, namely, the provision of capacity service to choice customers whose energy providers do not secure long-term capacity. The capacity charge established under Section 6w is intended to compensate the default supplier (i.e., the incumbent utility) for providing long-term capacity to customers, including customers of energy providers who supply energy but not long-term capacity. This is just one of many services associated with retail electric service that flows through to end-use customers as a retail charge.

The Commission notes that under Section 6w, the same charge applies to "load" whether it is bundled (receiving all services from the incumbent utility) or unbundled (receiving energy service from an AES that has chosen not to provide long-term capacity). And, like many states that designated either the incumbent utility or another entity to provide certain default services, Michigan is certainly within its rights to declare that the rate-regulated incumbent utility, certificated by the Commission to serve a specific service area, shall provide this critical long-term reliability service to designated customers. Of course, with this statutorily-mandated assignment of responsibility for the planning and provision of long-term capacity supplies comes the ability for the affected provider to charge applicable end-use customers taking this particular service from the utility. Supplying long-term capacity is as fundamental to ensuring electric reliability as maintaining the distribution system or other critical functions of the utility for which it is compensated by customers using the service.

THEREFORE, IT IS ORDERED that:

A. If a state reliability mechanism capacity charge is levied on retail open access customers at the conclusion of a show cause proceeding for planning year 2018-2021, it shall be for the first four consecutive planning years and any charge levied at the conclusion of a show cause proceeding shall be levied and applicable for a single year.

B. Beginning June 1, 2018, Upper Michigan Energy Resources Corporation shall implement a state reliability mechanism capacity charge of $229,523 per megawatt-year, or $629 per megawatt-day for full-service customers, using the Commission Staff's proposed year-round rate design, as illustrated in Attachments A and B attached to this order. Thirty days prior to June 1, 2018, Upper

Michigan Energy Resources Corporation shall file tariff sheets substantially similar to those contained in Attachment A, employing the capacity charge calculation in Attachment B. Due to the size of Attachment A, it is not physically attached to the original order contained in the official docket or paper copies of this order, but is electronically appended to this order, which is available on the Commission's website.

C. In Upper Michigan Energy Resources Corporation's annual power supply cost recovery reconciliation proceeding the amounts forecasted pursuant to MCL 460.6w(3)(b) shall be reconciled against actual amounts, consistent with the requirements of MCL 460.6w(4), as a separate reconciliation filed in the PSCR.

D. If an alternative electric supplier operating in Upper Michigan Energy Resources Corporation's service territory fails to make a satisfactory demonstration regarding its forward capacity obligations pursuant to MCL 460.6w(8), the resulting state reliability mechanism capacity charge shall be levied by Upper Michigan Energy Resources Corporation on the retail open access customers of that alternative electric supplier on a pro rata basis.

E. Upper Michigan Energy Resources Corporation is directed to file a standalone contested case for the annual review of its state reliability mechanism capacity charge by April 1, 2018, and annually thereafter, unless the utility expects that the annual review will be taking place in a rate case or power supply cost recovery case that will conclude by December 1 of each year. If Upper Michigan Energy Resources Corporation does not file a standalone contested case by April 1, 2018, it shall notify the Commission in this docket of the expected approval path and timing for the annual review of the state reliability mechanism capacity charge.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General - Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Sally A. Talberg, Chairman

Norman J. Saari, Commissioner

Rachael A. Eubanks, Commissioner

By its action of November 30, 2017.

Kavita Kale, Executive Secretary

RESIDENTIAL FULL REQUIREMENTS OR RETAIL ACCESS SERVICE RATE Rg1

AVAILABILITY
To customers contracting for residential full requirements or retail access service for periods of one year or more for separately metered residential dwelling units including those in residences, summer cottages, and apartment buildings.

HOURS OF SERVICE: Twenty-four.

CHARACTER OF SERVICE
Alternating current, 60 hertz, single-phase, three-phase or combination single and three-phase service.

RATE
Power Supply Charges: These charges are applicable to Full Requirements service.

	Capacity	*Non-Capacity*	*Total*
Non-Space heating:	***$0.04251***	***$0.04748***	$0.08999 per kWh

For customers with permanently installed electric space heating equipment which is the primary source of space heating, the following rate shall apply during the billing months of November through June:

	Capacity	*Non-Capacity*	*Total*
Space heating:	***$0.04251***	***$0.04748***	$0.08999 per kWh first 500 kWh per month
	$0.04251	***$0.04498***	$0.08749 per kWh excess of 500 kWh per month

Delivery Charges: These charges are applicable to Full Requirements and Retail Access service.

Facilities Charge:	per day per standard meter or service connection	
	$0.31582	single-phase
	$0.47373	three-phase
Distribution Charge:	$0.04772	per kWh
Excess Meter Charge:	$0.03288	per day per standard meter in excess of one

Power Supply and Delivery Charges are subject to the surcharges and credits shown on Sheet Nos. D-3.00 to D-7.00.

MINIMUM CHARGE
The monthly minimum charge shall be the Facilities Charge, the Renewable Energy Surcharge, and the Excess Meter Charge, if applicable.

PAYMENT: This rate is net.

LATE PAYMENT CHARGE
The late payment charge is 1.5%, not compounded, of the portion of the bill, net of taxes, that is delinquent. The late payment charge shall not apply to customers whose payments are made by the Department of Human Services or who are participating in a shut off protection program as described in the Consumer Standards and Billing Practices for Electric Residential Service (R460.101-460.169).

RETAIL ACCESS OPTION
Customers who meet the availability requirements of the Rg1 rate schedule may contract for residential retail access service. Retail access customers shall pay the above applicable Delivery Charges, Minimum Charge, and Late Payment Charge. Additionally, there is a $2.79452 per day charge for an interval demand meter or service connection if applicable. Customers taking retail access service are also subject to the Terms and Conditions contained in the Retail Access Service tariff rate schedule RAS-1, Section E.

CONDITIONS OF DELIVERY
See Sheet Nos. D-10.00 – D-11.00. In addition to the Conditions of Delivery noted, retail access service customers are also subject to the Terms and Conditions contained in the Retail Access Service tariff, Section E.

RESIDENTIAL FULL REQUIREMENTS SERVICE TIME-OF-USE RATE Rg2

AVAILABILITY
To residential customers contracting for full requirements service on a voluntary basis for electric service for domestic purposes for a period of one year or more. Customers are required to remain on the selected on-peak period for at least one year.

HOURS OF SERVICE: Twenty-four.

CHARACTER OF SERVICE
Alternating current, 60 Hertz, single-phase, three-phase, or combination single and three-phase service.

RATE
Delivery and Power Supply Charges:

Facilities Charge: per day per standard meter or service connection			
	$0.31582	single-phase	
	$0.47373	three-phase	
Distribution and Power Supply Charges:			
	Capacity	*Non-Capacity*	*Total*
	$0.13549	*$0.14161*	$0.27710 per kWh On-peak (a)
			$0.05818 per kWh Off-peak (b)
Excess Meter Charge:	$0.03288	per day per standard meter in excess of one	

Delivery and Power Supply Charges are subject to the surcharges and credits shown on Sheet Nos. D-3.00 to D-7.00.

(a) Residential on-peak usage is the energy in kilowatt-hours delivered during the on-peak period selected by the customer. The four on-peak periods available are: 7:00 a.m. to 7:00 p.m., 8:00 a.m. to 8:00 p.m., 9:00 a.m. to 9:00 p.m. and 10:00 a.m. to 10:00 p.m., prevailing time, Monday through Friday, excluding those days designated as legal holidays for New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.
(b) Residential off-peak usage is the energy in kilowatt-hours delivered during all hours other than on-peak hours.

MINIMUM CHARGE
The monthly minimum charge shall be the Facilities Charge, the Renewable Energy Surcharge, and the Excess Meter Charge, if applicable.

PAYMENT: This rate is net.

LATE PAYMENT CHARGE
The late payment charge is 1.5%, not compounded, of the portion of the bill, net of taxes, that is delinquent. The late payment charge shall not apply to customers whose payments are made by the Department of Human Services or who are participating in a shut off protection program as described in the Consumer Standards and Billing Practices for Electric Residential Service (R460.101-460.169).

CONDITIONS OF DELIVERY See Sheet Nos. D-10.00 – D-11.00.

(Continued on Sheet No. D-10.00)

GENERAL SECONDARY FULL REQUIREMENTS OR RETAIL ACCESS SERVICE RATE Cg1

AVAILABILITY

To customers contracting for secondary full requirements or retail access service for one year or more for general commercial, industrial, or governmental purposes.

HOURS OF SERVICE: Twenty-four.

CHARACTER OF SERVICE

Alternating current, 60 hertz, single-phase, three-phase, or combination single and three-phase service.

RATE

Power Supply Charges: These charges are applicable to Full Requirements service.

	Capacity	*Non-Capacity*	*Total*
	$0.04173	*$0.04798*	$0.08971 per kWh

Delivery Charges: These charges are applicable to Full Requirements and Retail Access service.

Facilities Charge:	per day per standard meter or service connection	
	$0.49315	single-phase
	$0.96986	three-phase
Distribution Charge:	$0.05443	per kWh
Excess Meter Charge:	$0.03288	per day per standard meter in excess of one

Power Supply and Delivery Charges are subject to the surcharges and credits shown on Sheet Nos. D-3.00 to D-7.00.

MINIMUM CHARGE

For regular service the monthly minimum charge shall be the Facilities Charge, the Renewable Energy Surcharge, the Energy Optimization Surcharge, and the Excess Meter Charge, if applicable. For auxiliary service the monthly minimum charge shall be as provided in conditions of delivery. See paragraph 6, Conditions of Delivery.

LATE PAYMENT CHARGE

A 1.5% per month late charge will be applied to outstanding charges past due.

RETAIL ACCESS OPTION

Customers who meet the availability requirements of the Cg1 rate schedule may contract for secondary retail access service. Retail access customers shall pay the above applicable Delivery Charges, Minimum Charge, and Late Payment Charge. Additionally, there is a $2.79452 per day charge for an interval demand meter or service connection if applicable. Customers taking retail access service are also subject to the Terms and Conditions contained in the Retail Access Service tariff rate schedule RAS-1, Section E.

CONDITIONS OF DELIVERY

See Sheet No. D-22.00. In addition to the Conditions of Delivery noted, retail access service customers are also subject to the Terms and Conditions contained in the Retail Access Service tariff, Section E.

GENERAL SECONDARY TOTAL ELECTRIC FULL REQUIREMENTS SERVICE Cg2

AVAILABILITY

To customers contracting for secondary full requirements service for one year or more for general commercial, industrial, or governmental purposes where electricity is used as the sole source of energy for space heating, water heating and all other uses. Service under this schedule is only available to premises currently served under this schedule. This schedule has been closed to new installations since February 5, 1985.

HOURS OF SERVICE: Twenty-four.

CHARACTER OF SERVICE

Alternating current, 60 hertz, single-phase, three-phase, or combination single and three-phase service.

RATE

Power Supply Charges:			
	Capacity	***Non-Capacity***	***Total***
	$0.04173	***$0.03948***	$0.08121 per kWh
Delivery Charges:			
Facilities Charge:	per day per standard meter or service connection		
	$0.49315	single-phase	
	$0.96986	three-phase	
Distribution Charge:	$0.05443	per kWh	
Excess Meter Charge:	$0.03288	per day per standard meter in excess of one	

Power Supply and Delivery Charges are subject to the surcharges and credits shown on Sheet Nos. D-3.00 to D-7.00.

MINIMUM CHARGE

The monthly minimum charge shall be the Facilities Charge, the Renewable Energy Surcharge, the Energy Optimization Surcharge, and the Excess Meter Charge, if applicable.

LATE PAYMENT CHARGE

A 1.5% per month late payment charge will be applied to outstanding charges past due.

CONDITIONS OF DELIVERY

1. The Company will generally furnish single-phase, 60 hertz service at 120/240 volts. Three-phase or combination single-phase and three-phase service will be furnished in accordance with the Electric Service Rules and Regulations of the Company.

2. When lighting service is furnished through one meter and power service through another, the registrations of the two meters will be added for billing purposes if the meters are installed at the same location. Where separately metered service is furnished for emergency exit lighting, fire alarm system or fire pump purposes the energy used will be accumulated and billed with the regular service, provided that it is furnished from the service connection which supplies regular service.

3. Service under this rate is for general use in commercial, industrial, and governmental establishments, including any group of three or more dwelling units which are served through one meter and comply with the Electric Service Rules and Regulations governing resale. When farming and commercial or industrial operations are combined, the applicable rate shall be determined by the predominant use of service.

4. At the request of a customer, service will be furnished under this rate at the available primary voltage by special arrangement under which the customer will agree to furnish, own and maintain at his expense all apparatus and material necessary for proper utilization of service at such voltage. In such cases the service will be metered at the supply voltage and kilowatthours registered will be reduced by 3%.

(Continued on Sheet No. D-14.00)

GENERAL SECONDARY FULL REQUIREMENTS OR RETAIL ACCESS SERVICE TIME-OF-USE RATE Cg3

AVAILABILITY

For customers contracting for secondary full requirements or retail access electric service for one year or more for general commercial, industrial or governmental purposes, and whose energy consumption is equal to or greater than 30,000 kWh per month, for three consecutive months. The customer must remain on this rate classification for 12 months before becoming eligible to transfer to a different general secondary rate. If the customer transfers from the Cg3 rate to a different rate, the customer must wait 12 months before they can transfer back to the Cg3 rate. This rate is available to customers previously served under the Cg3 rate schedule only after they have taken service for at least a 12-month period under another of the Company's rate schedules.

CHARACTER OF SERVICE

Alternating current, 60 hertz, single-phase, three-phase, or combination single and three-phase service.

RATE

Power Supply Charges: These charges are applicable to Full Requirements service.

Capacity Demand Charge:	***$16.564***	per kW Measured On-peak Demand
Non-Capacity Energy Charge:		
	$0.05833	per kWh On-Peak (a)
	$0.03807	per kWh Off-peak (b)

Delivery Charges: These charges are applicable to Full Requirements and Retail Access service.

Facilities Charge:	$2.79452	per day per standard meter or service connection
Demand Charge:	$5.592	per kW of Customer Maximum Demand
Distribution Charge:	$0.01221	per kWh On-peak (a)
	$0.01221	per kWh Off-peak (b)
Excess Meter Charge:	$0.13151	per day per standard meter in excess of one

Power Supply and Delivery Charges are subject to the surcharges and credits shown on Sheet Nos. D-3.00 to D-7.00.

(a) General Secondary on-peak usage is the energy in kilowatthours delivered between 9:00 a.m. and 9:00 p.m., prevailing time, Monday through Friday, excluding those days designated as legal holidays for New Years' Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

(b) General Secondary off-peak usage is the energy in kilowatthours delivered during all hours other than on-peak hours.

MINIMUM CHARGE

The monthly minimum charge shall be the Facilities Charge, the Renewable Energy Surcharge, the Energy Optimization Surcharge, the Excess Meter Charge, and the Customer Maximum Demand Charge. Auxiliary service shall be as provided in Paragraph 6, Conditions of Delivery, Sheet D-22.00.

LATE PAYMENT CHARGE

A 1.5% per month late payment charge will be applied to outstanding charges past due.

RETAIL ACCESS OPTION

Customers who meet the availability requirements of the Cg3 rate schedule may contract for secondary retail access service. Retail access customers shall pay the above applicable Delivery Charges, Minimum Charge, and Late Payment Charge. Customers taking retail access service are also subject to the Terms and Conditions contained in the Retail Access Service tariff rate schedule RAS-1, Section E.

CONDITIONS OF DELIVERY

See Sheet No. D-22.00. In addition to the Conditions of Delivery noted, retail access service customers are also subject to the Terms and Conditions contained in the Retail Access Service tariff, Section E.

(Continued on Sheet No. D-16.00)

GENERAL SECONDARY FULL REQUIREMENTS SERVICE – EXPERIMENTAL CURTAILABLE RATE Cg3C

AVAILABILITY

To customers who would otherwise qualify for General Secondary Service – Time-of-Use Rate Schedule Cg3, and contract for a minimum of 100 kilowatts of curtailable load. The Company reserves the right to limit participation to 10 customers.

RATE

Power Supply Charges:

Capacity Demand Charge:	***$16.564***	per kW Measured On-peak Demand
Curtailable Demand Credit	$0.02020	per kW per on-peak hour of use
Non-Capacity Energy Charge:		
	$0.05833	per kWh On-Peak (a)
	$0.03807	per kWh Off-peak (b)

The curtailable credit per kilowatt of curtailable demand for the billing period shall be determined by application of the following formula:

$$(A*B)*\frac{C}{D} \text{ where}$$

A = credit per kW of curtailable demand per on-peak hour-of-use
B = actual on-peak hours-of-use, determined by dividing the on-peak kWh for the billing period by the measured demand
C = 255 hours
D = on-peak hours in the billing period minus actual hours of capacity curtailment in the billing period

If the curtailable load is on isolated and separately metered circuits, it will be treated as a separate service to the customer.

Delivery Charge:

Facilities Charge:	$2.79452	per day per standard meter or service connection
Demand Charge:	$5.592	per kW of customer maximum demand
Distribution Charge:	$0.01221	per kWh On-peak (a)
	$0.01221	per kWh Off-peak (b)
Excess Meter Charge:	$0.13151	per day per standard meter in excess of one

Power Supply and Delivery Charges are subject to the surcharges and credits shown on Sheet Nos. D-3.00 to D-7.00.

(a) General Secondary on-peak energy usage is the energy in kilowatthours delivered between 9:00 a.m. and 9:00 p.m., prevailing time, Monday through Friday, excluding those days designated as legal holidays for New Years' Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.
(b) General Secondary off-peak energy usage is the energy in kilowatthours delivered during all hours other than on-peak hours.

MINIMUM CHARGE

The monthly minimum charge shall be the Facilities Charge, the Renewable Energy Surcharge, the Energy Optimization Surcharge, the Excess Meter Charge, and the Customer Maximum Demand Charge. Auxiliary service shall be as provided in Paragraph 6, Conditions of Delivery, Sheet D-22.00.

LATE PAYMENT CHARGE

A 1.5% per month late payment charge will be applied to outstanding charges past due.

(Continued on Sheet No. D-18.00)

SMALL SECONDARY FULL REQUIREMENTS SERVICE TIME-OF-USE RATE Cg5

AVAILABILITY

Available, on a voluntary basis, for a period of one year or more, to customers contracting for secondary full requirements electric service for general commercial, industrial, governmental or farm purposes.

HOURS OF SERVICE: Twenty-four.

CHARACTER OF SERVICE

Alternating current, 60 hertz, single-phase, three-phase, or combination single and three-phase service.

RATE

Delivery and Power Supply Charges:

Facilities Charge:	per day per standard meter or service connection		
	\$0.49315	single-phase	
	\$0.96986	three-phase	
Distribution and Power Supply Charges:			
	Capacity	***Non-Capacity***	***Total***
	\$0.012278	***\$0.015282***	\$0.27560 per kWh On-peak (a) \$0.06887 per kWh Off-peak (b)
Excess Meter Charge:	\$0.03288	per day per standard meter in excess of one	

Delivery and Power Supply Charges are subject to the surcharges and credits shown on Sheet Nos. D-3.00 to D-7.00.

(a) Small secondary on-peak energy usage is the energy in kilowatthours delivered between 9:00 a.m. and 9:00 p.m., prevailing time, Monday through Friday, excluding those days designated as legal holidays for New Years' Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

(b) Small Secondary off-peak energy usage is the energy in kilowatthours delivered during all hours other than on-peak hours.

MINIMUM CHARGE

The monthly minimum charge shall be the Facilities Charge, the Renewable Energy Surcharge, the Energy Optimization Surcharge, and the Excess Meter Charge. Auxiliary service shall be as provided in Paragraph 6, Conditions of Delivery, Sheet D-22.00.

LATE PAYMENT CHARGE

A 1.5% per month late payment charge will be applied to outstanding charges past due.

CONDITIONS OF DELIVERY

See Sheet No. D-22.00.

(Continued on Sheet No. D-14.00)

GENERAL PRIMARY FULL REQUIREMENTS OR RETAIL ACCESS SERVICE
TIME-OF-USE RATE Cp1

AVAILABILITY

To customers contracting for full requirements or retail access service - three-phase, 60 hertz power at approximately 2,400 volts or higher for periods of one year or more. Customers are required to remain on the selected on-peak period for at least one year.

RATES: (for service at primary voltages)	≤4,160 volts	>4,160 to ≤69,000 volts	≥69,000 volts
Power Supply Charges: These charges are applicable to Full Requirements service.			
Capacity Demand Charge: per kW of Measured On-peak Demand	*$16.610*	*$16.295*	*$15.971*
Non-Capacity Energy Charge: per kWh			
On-peak (b)	*$0.05805*	*$0.05674*	*$0.05561*
Off-peak (c)	*$0.03789*	*$0.03703*	*$0.03630*
Delivery Charges: These charges are applicable to Full Requirements and Retail Access service.			
Facilities Charge: per day	$20.21918	$20.21918	$20.21918
Demand Charge: per kW of Customer Maximum Demand	$4.313	$4.231 OR $0.200(a)	$0
Distribution Charge: per kWh			
On-peak (b)	$0.01203	$0.01180 OR $0.00124(a)	$0
Off-peak (c)	$0.01203	$0.01180 OR $0.00124(a)	$0
Power Factor Demand Charge: per kW of Power Factor Demand	$18.204	$17.907	$12.184

Power Supply and Delivery Charges are subject to the surcharges and credits shown on Sheet Nos. D-3.00 to D-7.00.

For Determination of Demand, see Sheet No. D-25.00.

(a) Charge for customer who takes service at 13,200 volts or greater, but less than 69,000 volts, directly from a company-owned substation transformer, and is served using no company-owned primary lines.
(b) General primary on-peak usage is the energy in kilowatthours delivered during the on-peak period selected by the customer. The two on-peak periods available are: 8:00 a.m. to 8:00 p.m. and 10:00 a.m. to 10:00 p.m., prevailing time, Monday through Friday, excluding those days designated as legal holidays for New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.
(c) General Primary off-peak usage is the energy in kilowatthours delivered during all hours other than on-peak hours.

MINIMUM CHARGE

The monthly minimum charge shall be the Facilities Charge, the Renewable Energy Surcharge, the Energy Optimization Surcharge, plus the charge for 300 kW of measured on-peak demand plus the charge for 300 kW of customer maximum demand.

LATE PAYMENT CHARGE

A 1.5% per month late payment charge will be applied to outstanding charges past due.

(Continued on Sheet No. D-24.00)

GENERAL PRIMARY FULL REQUIREMENTS SERVICE INTERRUPTIBLE RATE Cp2

AVAILABILITY

To customers contracting for three-phase 60 hertz full requirements power service at approximately 2,400 volts or higher for periods of five years with a minimum 15 minute integrated demand of 1,000 kilowatts of interruptible load. Customers are required to remain on the selected on-peak period for at least one year.

RATES: (for service at primary voltages)	≤4,160 volts	>4,160 to ≤69,000 volts	≥69,000 volts
Power Supply Charges:			
Demand Charge: per kW of Measured On-peak Demand	***$13.630***	***$13.405***	***$13.201***
Non-Capacity Energy Charge: per kWh			
On-peak (b)	***$0.05805***	***$0.05674***	***$0.05561***
Off-peak (c)	***$0.03789***	***$0.03703***	***$0.03630***
Delivery Charges:			
Facilities Charge: per day	$20.21918	$20.21918	$20.21918
Customer may be exempt from this facilities charge if taking service at the same location on rate schedule Cp-1			
Demand Charge: per kW of Customer Maximum Demand	$4.313	$4.231 OR $0.200(a)	$0
Distribution Charge: per kWh			
On-peak (b)	$0.01203	$0.01180 OR $0.00124(a)	$0
Off-peak (c)	$0.01203	$0.01180 OR $0.00124(a)	$0
Power Factor Demand Charge: per kW of Power Factor Demand	$18.204	$17.907	$12.184

Power Supply and Delivery Charges are subject to the surcharges and credits shown on Sheet Nos. D-3.00 to D-7.00.

For Determination of Demand, see sheet No. D-25.00.

(a) Charge for customer who takes service at 13,200 volts or greater, but less than 69,000 volts, directly from a company-owned substation transformer, and is served using no company-owned primary lines.
(b) General primary on-peak usage is the energy in kilowatthours delivered during the on-peak period selected by the customer. The two on-peak periods available are: 8:00 a.m. to 8:00 p.m. and 10:00 a.m. to 10:00 p.m., prevailing time, Monday through Friday, excluding those days designated as legal holidays for New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.
(c) General Primary off-peak usage is the energy in kilowatthours delivered during all hours other than on-peak hours.

MINIMUM CHARGE

The monthly minimum charge shall be the applicable Facilities Charge, the Renewable Energy Surcharge, the Energy Optimization Surcharge, plus the charge for 700 kilowatts of measured on-peak demand, plus the charge for 700 kW of customer maximum demand.

LATE PAYMENT CHARGE

A one and one half percent (1.5%) per month late payment charge will be applied to outstanding charges past due.

(Continued on Sheet No. D-28.00)

GENERAL PRIMARY FULL REQUIREMENTS SERVICE CURTAILABLE RATE Cp3

AVAILABILITY

To customers contracting for three-phase 60 hertz full requirements power service at approximately 2,400 volts or higher with a minimum of 500 kilowatts of curtailable load. If the curtailable load is on isolated and separately metered circuits, it will be treated as a separate service to the customer. Customers are required to remain on the selected on-peak period for at least one year.

RATES: (for service at primary voltages)	≤4,160 volts	>4,160 to ≤69,000 volts	≥69,000 volts
Power Supply Charges:			
Capacity Demand Charge: per kW of Measured On-peak Demand	*$16.610*	*$16.295*	*$15.971*
Curtailable Demand Credit: per kW per on-peak hr of use	$0.0199	$0.0195	$0.0191
Non-Capacity Energy Charge: per kWh			
On-peak (b)	*$0.05805*	*$0.05674*	*$0.05561*
Off-peak (c)	*$0.03789*	*$0.03703*	*$0.03630*

The curtailable credit per kilowatt of curtailable demand for the billing period shall be determined by application of the following formula:

$$(A * B) * \frac{C}{D} \quad \text{where}$$

A = credit per kW of curtailable demand per on-peak hour of use
B = actual on-peak hours-of-use, determined by dividing the on-peak kWh for the billing period by the sum of the measured on-peak demand and power factor demand.
C = 255 hours
D = on-peak hours in the billing period minus actual hours of curtailment in the billing period

Delivery Charges:			
Facilities Charge: per day	$20.21918	$20.21918	$20.21918
Demand Charge: per kW of Customer Maximum Demand	$4.313	$4.231 OR $0.200(a)	$0
Distribution Charge: per kWh			
On-peak (b)	$0.01203	$0.01180OR $0.00124(a)	$0
Off-peak (c)	$0.01203	$0.01180OR $0.00124(a)	$0
Power Factor Demand Charge: per kW of Power Factor Demand	$18.204	$17.907	$12.184

Power Supply and Delivery Charges are subject to the surcharges and credits shown on Sheet Nos. D-3.00 to D-7.00.

(a) Charge for customer who takes service at 13,200 volts or greater, but less than 69,000 volts, directly from a company-owned substation transformer, and is served using no company-owned primary lines.
(b) General Primary on-peak usage is the energy in kilowatthours delivered during the on-peak period selected by the customer. The two on-peak periods available are:8:00 a.m. to 8:00 p.m. and 10:00 a.m. to 10:00 p.m., prevailing time, Monday through Friday, excluding those days designated as legal holidays for New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.
(c) General Primary off-peak usage is the energy in kilowatt-hours delivered during all hours other than on-peak hours.

(Continued on Sheet No. D-30.00)

GENERAL PRIMARY FULL REQUIREMENTS OR RETAIL ACCESS SERVICE MANDATORY STANDBY RATE Cp4

AVAILABILITY

To customers contracting for three-phase 60 hertz full requirements or retail access power service at approximately 2,400 volts or higher for periods of one year or more (see Conditions of Delivery No. 3) that have a generator that normally operates in parallel with the Company's system and serves load which will transfer from the customer's to the Company's system during planned and/or unplanned outages of the customer's generation. Standby service has limitations, more fully described in the Terms and Conditions section, when used in conjunction with curtailable or interruptible service at the same location.

RATES: (for service at primary voltages)	≤4,160 volts	>4,160 to ≤69,000 volts	≥69,000 volts
Power Supply Charges: These charges are applicable to Full Requirements service.			
Capacity Demand Charge: per kW of Measured On-peak Demand	***$16.610***	***$16.295***	***$15.971***
Standby Demand Charge: per kW	$1.748	$1.715	$1.680

Standby Energy: In addition to the charges below, Standby Energy will be billed at the system avoided cost of power plus 10% per kWh, less the appropriate on or off-peak energy charge per kWh (including the Power Supply Recovery Factor), but not less than zero.

	≤4,160 volts	>4,160 to ≤69,000 volts	≥69,000 volts
Non-Capacity Energy Charge: per kWh			
On-peak (b)	***$0.05805***	***$0.05674***	***$0.05561***
Off-peak (c)	***$0.03789***	***$0.03703***	***$0.03630***
Delivery Charges: These charges are applicable to Full Requirements and Retail Access service.			
Facilities Charge: per day			
First metering point	$20.21918	$20.21918	$20.21918
Per additional metering point	$6.57534	$6.57534	$6.57534
Demand Charge: per kW of Maximum Total Demand	$4.313	$4.231 OR $0.200(a)	$0
Distribution Charge: per kWh			
On-peak (b)	$0.01203	$0.01180 OR $0.00124(a)	$0
Off-peak (c)	$0.01203	$0.01180 OR $0.00124(a)	$0
Power Factor Demand Charge: per kW of Peak Power Factor Demand	$18.204	$17.907	$12.184

Power Supply and Delivery Charges are subject to the surcharges and credits shown on Sheet Nos. D-3.00 to D-7.00.

(a) Charge for customer who takes service at 13,200 volts or greater, but less than 69,000 volts, directly from a company-owned substation transformer, and is served using no company-owned primary lines.
(b) Customers shall select one of two on-peak periods which shall be either from 8:00 a.m. to 8:00 p.m. or from 10:00 a.m. to 10:00 p.m., as selected by the customer, prevailing time, Monday through Friday, excluding those days designated as legal holidays for New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.
(c) The off-peak period shall be those hours not designated as on-peak.

The customer's selection will remain in effect for at least one year and may be changed, at the customer's request, once a year, thereafter.

(Continued on Sheet No. D-34.00)

GENERAL PRIMARY FULL REQUIREMENTS OR RETAIL ACCESS SERVICE SCHEDULE A

AVAILABILITY
To CMP Holdings LLC d/b/a Verso Papers LLC at their 138/13.8 kilovolt substation in Quinnesec, Michigan.

HOURS OF SERVICE: Twenty-four.

CHARACTER OF SERVICE
Alternating current, 60 hertz, three-phase at 138,000 volts.

RATE
Power Supply Charges: These charges are applicable to Full Requirements service.
Capacity Demand Charge: *$22.136* per kW of billed demand
Subject to a minimum monthly demand charge of 300 kW of billed demand.

Standby Demand Charge: $0.919 per kW
Non-Capacity Energy Charge: ***$0.04686*** per kWh On-peak
$0.03059 per kWh Off-peak

Additional Charge for Standby Energy:
In addition to the charges above, Standby Energy will be billed at the following rates:
$0.03000 per kWh On-peak
$0.02000 per kWh Off-peak

Curtailable Credit: per kW of Curtailable On-Peak Demand
Determined by application of the following formula where the credit per kW per on-peak hours of use equals $0.01910:

$$(A*B)*\frac{C}{D} \text{ where}$$

A = credit per kW per on-peak hour of use
B = actual curtailable on-peak hours of use, determined by dividing the on-peak curtailable kWh for the billing period by the curtailable on-peak demand
C = 255 hours
D = on-peak hours in the billing period minus actual hours of curtailment in the billing period

Delivery Charges: These charges are applicable to Full Requirements and Retail Access service.
Demand Charge: $0.196 per kW of Maximum Total demand
Subject to a minimum monthly demand charge of 300 kW of Maximum Total Demand.

Power Factor Demand Charge:	$12.184	per kW of Peak Power Factor Demand
Distribution Charge:	$0.00122	per kWh of on-peak and off-peak energy

Power Supply and Delivery Charges are subject to the surcharges and credits shown on Sheet Nos. D-3.00 to D-7.00.

For Determination of Demand, see Sheet No. D-36.00 – D-38.00

MINIMUM CHARGE
The monthly minimum charge shall be the Demand Charges, the Renewable Energy surcharge and the Energy Optimization surcharge.

LATE PAYMENT CHARGE
A 1.5% per month Late Payment Charge will be applied to outstanding charges past due.

(Continued on Sheet No. D-37.00)

GENERAL PRIMARY FULL REQUIREMENTS AND RETAIL ACCESS SERVICE – LARGE CURTAILABLE CONTRACT RATE CpLC

AVAILABILITY

To customers contracting for three-phase 60 hertz full requirements power service at approximately 13.8 kilovolts or higher with a minimum of 50 megawatts of curtailable load. If the curtailable load is on isolated and separately metered circuits, it will be treated as a separate service to the Customer. Customers are required to remain on the selected on-peak period for at least one year.

RATES (for service at primary voltages)	13.8 kV to <69 kV	≥69 kV
Distribution Charges:		
Facilities Charge: per day	$20.21918	$20.21918
Demand Charge: Per kW of Customer Maximum Demand	$4.231 OR $0.187(a)	$0.00
Delivery Charge: Per On- and Off-Peak kWh	$0.01180 OR $0.00029(a)	$0.00
Power Factor Demand Charge: Per kW of Power Factor Demand	$6.814	$6.625
Power Supply Charges:		
Capacity Demand Charge: per kW of Measured On-peak Demand	***$18.565***	***$18.170***
Curtailment Demand Credit: Per kW of Maximum Measured On-Peak Customer Curtailable Demand	$5.635	$5.560
Non-Capacity Energy Charge: per kWh		
On-Peak (b)	***$0.04955***	***$0.04850***
Off-Peak (c)	***$0.03482***	***$0.03408***

(a) Charge for Customer that takes service at 13,800 volts or greater, but less than 69,000 volts, directly from a Company-owned substation transformer, and is served using no Company-owned primary lines.

(b) General Primary on-peak usage is the energy in kilowatthours delivered during the on-peak period selected by the Customer. The two on-peak periods available are: 8:00 a.m. to 8:00 p.m. and 10:00 a.m. to 10:00 p.m., prevailing time, Monday through Friday, excluding those days designated as legal holidays for New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

(c) General Primary off-peak usage is the energy in kilowatthours delivered during all hours other than on-peak hours.

For Determination of Demand, see Sheet Nos. D-40.00 – D-41.00.

Subject to Power Supply Cost Recovery Factor.

Power Supply and Distribution charges are subject to the surcharges and credits shown on Sheet Nos. D-3.00 to D-7.00

MINIMUM CHARGE

The monthly minimum charge shall be the Facilities Charge, the Renewable Energy Surcharge, the Energy Optimization Surcharge, plus the Demand Charge for Contract Demand. Contract Demand shall be no less than 50 megawatts.

LATE PAYMENT CHARGE

A 1.5% per month Late Payment Charge will be applied to outstanding charges past due.

(Continued on Sheet No. D-41.00)

STANDARD STREET RATE Ms2

AVAILABILITY

To municipalities and other government units contracting for standard high pressure sodium or metal halide lighting for illumination of public streets roadways and alleys by means of Company-owned street lighting facilities.

CHARACTER OF SERVICE

Alternating current, 60 hertz, single-phase at 120/240 volts.

RATE

Non-Capacity Monthly Charge per Lighting Unit

Lamp Size	Amount
50 watt	$*7.91* Sodium
70 watt	$*9.68* Sodium
100 watt	$*11.54* Sodium
150 watt	$*13.70* Sodium
175 watt	$*16.32* Metal Halide
200 watt	$*16.22* Sodium
250 watt	$*18.64*Sodium
250 watt	$*20.25* Metal Halide
400 watt	$*25.26* Sodium
400 watt	$*25.86* Metal Halide

Capacity Energy Charge: $0.03005 per all kWh

Subject to the surcharges and credits shown on Sheet Nos. D-3.00 to D-7.00.

MINIMUM CHARGE

The monthly minimum charge shall be the monthly charge per lighting unit and the Energy Optimization Surcharge.

LATE PAYMENT CHARGE

A 1.5% per month late payment charge will be applied to outstanding charges past due.

CONDITIONS OF DELIVERY

1. The Company will furnish, install, own and operate a standard high pressure sodium or metal halide street lighting unit, and will supply all electrical energy and normal maintenance for the operation of the unit. The standard street lighting unit shall consist of a cobra head fixture on an arm mounted on an existing Company-owned wood pole, with a control device wired for operation. This rate requires use of existing Company-owned poles and available overhead 120 volt service where the Company has such facilities along streets, alleys and highways. Where additional primary and/or secondary facilities are required, the customer shall pay, in advance, material and installation cost of such additional facilities.
2. When necessary, the Customer shall grant or obtain permissions, easements, ordinance satisfaction, and/or permits to the Company to install / remove lighting facilities on public or private property without expense to the Company. The Customer is responsible for marking all privately owned underground facilities. If such facilities are not marked correctly and are subsequently damaged, the Customer is responsible for damages. All installations shall be in accordance with the construction standards of the Company and any other codes the Company determines to be applicable.
3. Underground service is available under this rate for new installations, where the customer pays the estimated cost of furnishing underground service.
4. Lamps will automatically be switched on approximately 30 minutes after sunset and off 30 minutes before sunrise providing dusk-to-dawn operation of approximately 4200 hours per year. Non standard, seasonal, temporary or part-night service is not available under this rate.

(Continued on Sheet No. D-45.00)

STANDARD STREET RATE Ms2
(Continued from Sheet No. D-44.00)

CONDITIONS OF DELIVERY (Cont.)

5. The Company will initiate a first response to replace inoperative lamps and otherwise maintain luminaires during regular daytime work hours within 72 hours after notification by the Customer. Conditions may require repeat visits to complete repairs. No credit will be allowed for periods during which lamps were out of service.

6. The Company will, at the Customer's expense, modify, replace, transfer, relocate or temporarily remove and reinstall any properly operating poles or fixtures contracted for under this rate as requested in writing by the customer or as required by a governing authority.

7. The lighting agreement shall become effective on the date service is connected, and shall continue in force until terminated upon 30 days prior written notice given by either of the parties to the other. The Company may remove any and/or all lighting facilities upon termination.

8. If the Customer or governing authority terminates service or requests the permanent removal of any Company-owned street lighting facilities within 60 months of installation, the Customer shall pay the lesser of the estimated labor charges for installation and removal of the equipment, or the remaining balance of monthly fees to satisfy the 60 month period. Permanent removal of pole mounted street lighting facilities more than 60 months after installation shall be at no cost to the Customer.

9. Subject to Company approval, the Company will allow municipal customers to make temporary attachments of Christmas lighting and/or decorations on the Company-owned light poles. The Customer must execute an annual agreement for such attachments, and must meet all conditions thereof. Estimated energy consumption will be billed under the current CG1 energy rate. Time and material charges for installation, removal or associated maintenance may also apply.

10. Electric service will not be furnished hereunder for breakdown or standby purposes where another source of power is available for the Customer. Energy furnished under this rate shall not be used for purposes other than those specified hereunder and shall not be resold.

11. In the event of abnormal or excessive maintenance due to frequent vandalism or other causes, not related to the quality of material or workmanship, the Customer shall reimburse the Company for all associated costs.

12. Where the Company has secondary voltage in the area and it is not necessary to install a transformer or extend secondary lines more than one hundred and fifty feet, the Company will connect Customer-owned flasher signal lamps and bill on a flat monthly rate according to the following schedule:

Per Flasher	Installed Capacity		
Capacity	*Non-Capacity*	*Total*	
$1.13	*$2.76*	$3.89	75 watts or less
$1.73	*$4.25*	$5.98	Greater than 75 watts up to and including 150 watts

If the Company must install a transformer or extend lines more than one hundred and fifty feet or if the installed capacity exceeds 150 watts, the flasher signals will be billed on the general secondary rate applicable in the area served.

13. Customer shall indemnify and hold harmless the Company, from and against any and all liability for injuries or damages to persons or property arising or resulting from (a) any interruption or modification of service requested or caused by the Customer; or (b) any lighting, requested by Customer or third party, which does not conform to the Illuminating Engineering Society (IES) Recommended Practices.

NON-STANDARD STREET AND AREA LIGHTING, COMPANY-OWNED RATE Ms3

AVAILABILITY

To all customers contracting for non standard lighting service by means of Company-owned and maintained non-standard street lighting and related facilities. The availability of Option B – facilities charge is limited to customers who have paid, in full, the estimated installed cost of lighting and related facilities.

CHARACTER OF SERVICE

Alternating current, 60 hertz, single-phase at 120/240 volts.

RATE

Facilities Charge:

Option A: Monthly facilities charge of one point nine percent (1.9%) of the estimated installed cost of the lighting and related facilities.

Option B: One time charge equal to the estimated installed cost of the lighting and related facilities, paid prior to installation of facilities, and monthly facilities charge of one-half of one percent (0.5%) of the estimated installed cost of the lighting and related facilities.

Non-Capacity Monthly Charge per Non-Standard Lighting Unit:

Option A and B:	Lamp Size	Amount
	50 watt	***$2.18***
	70 watt	***$3.20***
	100 watt	***$4.96***
	150 watt	***$7.03***
	175 watt	***$7.96***
	200 watt	***$9.31***
	250 watt	***$11.58***
	400 watt	***$17.89***
	1000 watt	***$41.67***

Capacity Energy Charge: $0.03005 per all kWh

Subject to the surcharges and credits shown on Sheet Nos. D-3.00 to D-7.00.

MINIMUM CHARGE

The monthly minimum charge shall be the monthly charge per lighting unit and the Energy Optimization Surcharge.

LATE PAYMENT CHARGE

A 1.5% per month late payment charge will be applied to outstanding charges past due.

CONDITIONS OF DELIVERY

1. The Company will furnish, install, own and operate a complete non standard lighting unit and will supply all electric energy and normal maintenance for the operation of the unit. A lighting unit may consist of a pole and/or luminaire with a bracket, lamp and control device wired for operation. The unit may be fed overhead or underground. Where additional primary and/or secondary facilities are required, the Customer shall pay the full cost of installation.

2. When necessary, the Customer shall grant or obtain permissions, easements, ordinance satisfaction, and/or permits to the Company to install / remove lighting facilities on public or private property without expense to the Company. The Customer is responsible for marking all privately owned underground facilities. If such facilities are not marked correctly and are subsequently damaged, the Customer is responsible for damages. All installations shall be in accordance with the construction standards of the Company and any other codes the Company determines to be applicable.

(Continued on Sheet No. D-47.00)

STANDARD AREA LIGHTING SERVICE RATE GL1

AVAILABILITY

To all classes of customers contracting for standard area lighting service whenever service can be provided from existing 120-volt, Company-owned facilities. Rate is not available for lighting public streets, alleys, or highways. The Company will no longer install new or additional poles under this rate. Installations which require new poles shall be served under the Ms-3 rate.

CHARACTER OF SERVICE

Alternating current, 60 hertz, single-phase at 120 volts.

RATE

Non-Capacity Monthly Charge per Lighting Unit

	Sodium		Metal Halide	
Lamp Size	Standard	Flood	Flood	Standard
50 watt	*	*	*	*
70 watt	*$9.59*	*	*	*
100 watt	*$11.43*	*$13.26*	*	*
150 watt	*$13.57*	*	*	*
175 watt	*	*	*	*$16.17*
200 watt	*$16.07*	*$17.78*	*	*
250 watt	*$18.47*	*	*$20.87*	*$20.07*
400 watt	*$25.03*	*$26.47*	*$27.09*	*$25.62*

*Not available

Capacity Energy Charge: $0.03005 per all kWh

Subject to the surcharges and credits shown on Sheet Nos. D-3.00 to D-7.00.

MINIMUM CHARGE

The monthly minimum charge shall be the monthly charge per lighting unit and the Energy Optimization Surcharge.

LATE PAYMENT CHARGE

A 1.5% per month late payment charge will be applied to outstanding charges past due.

CONDITIONS OF DELIVERY

1. The Company will furnish, install, own and operate a standard high pressure sodium or metal halide area or flood lighting unit and will supply all electric energy and normal maintenance for the operation of the unit. The standard lighting unit will consist of an open bottom or cobra head area light fixture on a 2 to 6 foot arm or directional floodlight on a 2 foot arm, mounted on an existing Company-owned wood pole, with a control device wired for operation. This rate requires use of existing Company-owned wood poles and available overhead 120 volt service. Where additional primary and/or secondary facilities are required, the Customer shall pay the full cost of installation.
2. New poles required solely for the attachment of lighting fixtures are not available under this rate. Poles and circuit being provided by the Company prior to 9-16-02 will continue to be provided for monthly charge of $2.58 for each pole and $2.54 for each span of circuit installed.
3. When necessary, the Customer shall grant or obtain permissions, easements, ordinance satisfaction, and/or permits to the Company to install / remove lighting facilities on public or private property without expense to the Company. The Customer is responsible for marking all privately owned underground facilities. If such facilities are not marked correctly and are subsequently damaged, the Customer is responsible for damages. All installations shall be in accordance with the construction standards of the Company and any other codes the Company determines to be applicable.

(Continued on Sheet No. D-49.00)

LED STREET LIGHTING SERVICE RATE LED1

AVAILABILITY

To all municipal or governmental customers contracting for LED (light emitting diode) street lighting service by means of Company-owned and maintained lighting facilities subject to the availability of Company approved materials and completion of required engineering. This tariff is available until June 30, 2014.

RATE

Facilities Charge:

One time charge equal to the estimated installed cost of the lighting and related facilities, paid prior to installation of facilities, and monthly facilities charge of one half of one percent (0.5 %) of the estimated installed cost of all lighting and related facilities.

Energy Charge:

Capacity	***Non-Capacity***	***Total***
$0.01719	***$0.08062***	$0.09781 per kWh

The kWh usage to be billed shall be calculated by multiplying the rated input wattage of the original fixture and related accessory equipment by 350 hours.
Subject to the surcharges and credits shown on Sheet Nos. D-3.00 to D-7.00.

LATE PAYMENT CHARGE

A 1.5% per month late payment charge will be applied to outstanding charges past due.

CONDITIONS OF DELIVERY

1. Upon completion of a signed Agreement and payment, the Company will furnish, install, own and operate a complete LED lighting unit and will supply all electric energy and normal maintenance for the operation of the unit. A lighting unit may include an LED fixture, bracket, control, and monitoring device. This rate requires use of existing Company-owned wood poles and available 120-volt service. Where additional primary and/or secondary facilities are required, the Customer shall pay the full cost of installation.

2. The Company will initiate a first response to maintain lighting units within 72 hours of notification by the Customer. Conditions may require repeat visits to complete repairs. No credit will be allowed for periods during which luminaires are out of service, and no adjustments will be made to the Facilities Charge or energy consumption as a result of component or unit replacement. After a period of 10 years from installation, normal maintenance shall continue but replacement of the fixture or major fixture components are at Customer discretion and require reimbursement of expenses and a new or revised Agreement.

3. In the event of abnormal or excessive maintenance due to frequent vandalism or other causes not related to the quality of material or workmanship, the Customer shall reimburse the Company for all associated costs. The Company shall be responsible for tree trimming only within those work zones which are restricted to qualified utility workers.

4. Luminaires will automatically be switched on approximately 30 minutes after sunset and off 30 minutes before sunrise, providing dusk-to-dawn operation approximately 4,200 hours per year.

5. The Company will, at Customer's expense, modify, replace, relocate, change the position, or temporarily remove and reinstall any properly operating Company-owned poles or fixtures contracted for under this rate as requested in writing by the Customer or as required by a governing authority.

6. If the Customer, or a governing authority, terminates service or requests the permanent removal of any Company-owned LED lighting facilities within 10 years of installation, the Customer shall reimburse the Company for the lesser of the estimated labor charges for removal of the equipment, or the remaining balance of Facilities Charges to satisfy the 10 year period. Permanent removal of pole mounted lighting facilities more than 10 years after installation shall be at no cost to the Customer.

(Continued on Sheet No. D-51.00)

SECONDARY SERVICE FOR MUNICIPAL DEFENSE SIREN SERVICE RATE Mg1

AVAILABILITY

To incorporated municipalities for the periodic operation of defense sirens.

RATE

Capacity	*Non-Capacity*	*Total*
$0.86	*$2.12*	$2.98 per year or any part of a year for each 2 horsepower or fraction

thereof for each siren installed.

Subject to the surcharges and credits shown on Sheet Nos. D-3.00 to D-7.00.

MINIMUM ANNUAL CHARGE:

The annual charge per siren plus the Energy Optimization Surcharge for each month of the year or any part of a year.

LATE PAYMENT CHARGE

A 1.5% per month late payment charge will be applied to outstanding charges past due.

CONDITIONS OF DELIVERY

1. Bills will be rendered in the fourth quarter of each year, for each municipality, for service rendered in the aggregate during the calendar year.

2. The municipality shall furnish and install all sirens, including the labor and materials required for approved service connections to the nearest Company distribution line.

3. Where additional equipment or extension of lines is necessary on the part of the Company, the municipality shall pay the Company its cost of making such extension.

4. The Company will make the connection and disconnection with its distribution lines.

5. Loads other than sirens shall not be connected to the siren circuit.

6. The municipality shall furnish the Company with a map indicating the location of sirens to be operated, and shall give adequate notice of the discontinuance or addition of any sirens.

7. Service may be terminated at any time by the municipality or on six months' notice by the Company.

D2. RESIDENTIAL SERVICE **Rg-1M**

AVAILABILITY

This schedule is available for single-phase service to residential customers who are not required to take service under the Power Supply Default Service (PSDS). Customers taking service under the Retail Access Service Tariff (RAST) shall be responsible for the Distribution Charges but not the Power Supply Charges under this rate schedule. Customers that purchase power supply service from the Company shall be subject to both the Distribution and Power Supply charges contained in this rate schedule.

MONTHLY RATE

Distribution Service

Fixed Charge

Daily	Monthly	
$0.3945	$12.00	Year-Round Customers
$0.7890	$24.00	Seasonal Customers

Energy Charge

All kWh: $0.03433/kWh

Power Supply Service (Optional)

Energy Charge	*Capacity*	*Non-Capacity*	*Total*
All kWh:	*$0.03040*	*$0.04804*	$0.07844/kWh

MINIMUM CHARGE

The monthly minimum charge is the fixed charge.

POWER SUPPLY COST RECOVERY CLAUSE	See Schedule PSCR, starting on Sheet D-100.00.
APARTMENT BUILDINGS & MULTIPLE DWELLINGS	See Schedule RgX starting on Sheet D-102.00.
COMBINED SERVICE	See Schedule RgX starting on Sheet D-102.00.
THREE PHASE SERVICE	See Schedule RgX starting on Sheet D-102.00.
SEASONAL BILLING	See Schedule RgX starting on Sheet D-102.00.
SPACE HEATING	See Schedule RgX starting on Sheet D-102.00.
WATER HEATING	See Schedule RgX starting on Sheet D-103.00.
PARALLEL GENERATION	See Schedule PG starting on Sheet D-137.00.
ENERGY OPTIMIZATION	See Schedule EO starting on Sheet D-156.00.

D2. RESIDENTIAL SERVICE – OPTIONAL TIME-OF-USE **RG-OTOU-1M**

AVAILABILITY

This schedule is available upon written request for single phase service to residential customers on a voluntary basis for a minimum period of one year. This schedule is available to customers who are not required to take service under the Power Supply Default Service (PSDS). Customers taking service under the Retail Access Service Tariff (RAST) shall be responsible for the Distribution Charges but not the Power Supply Charges under this rate schedule. Customers that purchase power supply service from the Company shall be subject to both the Distribution and Power Supply charges contained in this rate schedule.

MONTHLY RATE

Distribution Service

Fixed Charge

Daily	Monthly	
$0.3945	$12.00	Year-round customers
$0.7890	$24.00	Seasonal customers

Energy Charge

On-Peak: All kWh at $0.05704/kWh

Off-Peak: All kWh at $0.01426/kWh

Power Supply Service (Optional)

Energy Charge	*Capacity*	*Non-Capacity*	*Total*
On-Peak: All kWh at	*$0.09667*	*$0.09246*	$0.18913/kWh
Off-Peak: All kWh at		$0.04728/kWh	

PRICING PERIOD DEFINITIONS

On-Peak Periods

The following periods on Monday, Tuesday, Wednesday, Thursday, and Friday, excluding holidays:

1. Summer (Calendar Months of May - September)
   Option 1: 9:00 AM to 7:00 PM
   Option 2: 10:00 AM to 8:00 PM
2. Winter (Calendar Months of October - April)
   Option 1: 8:00 AM to 12:00 noon and 4:00 PM to 9:00 PM
   Option 2: 9:00 AM to 12:00 noon and 4:00 PM to 10:00 PM

Customer must choose the same option number during both the winter and summer periods.

Off-Peak Periods

All hours not included as on-peak hours above.

HOLIDAYS

The days of the year which are considered holidays are New Year's Day, Good Friday, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, Friday After Thanksgiving, Day Before Christmas, Christmas Day, and Day Before New Year's Day.

MINIMUM CHARGE

The monthly minimum charge is the fixed charge.

(Continued on Sheet No. D-106.00)

Issued April 11, 2017
T. T. Eidukas
Vice-President,
Milwaukee, Wisconsin

Effective for service rendered on and after April 24, 2017

Issued under authority of the Michigan Public Service Commission dated April 23, 2015 in Case No. U-17669

D3. SMALL COMMERCIAL & INDUSTRIAL SERVICE **Cg-1M**

AVAILABILITY

This schedule is available to small commercial and industrial customers where neither of the following have been exceeded for three consecutive months and also exceeded for at least one month in each succeeding rolling 12-month period:

1. Total demand of 100 kW; or.
2. Total monthly energy consumption of 12,500 kWh.

Customers taking service on the Cg-1M rate as of the effective date of the Commission Order in Case No. U-13688, that qualify for CP-1M by exceeding 100 KW of demand or 25,000 kwh for three consecutive months prior to September 1, 2004, have the option to remain on the applicable energy only rate. These customers will be subject to the following customer charges:$255.00/month or $8.3836/day for year-round customer charge or a $510/month or $16.7671/day seasonal customer charge.

This schedule is available to customers who are not required to take service under the Power Supply Default Service (PSDS). Customers taking service under the Retail Access Service Tariff (RAST) shall be responsible for the Distribution Charges but not the Power Supply Charges under this rate schedule. Customers that purchase power supply service from the Company shall be subject to both the Distribution and Power Supply charges contained in this rate schedule.

MONTHLY RATE

Distribution Service

Fixed Charge

Daily	Monthly	
$0.8219	$25.00	Year-Round Customers
$1.6438	$50.00	Seasonal Customers

Energy Charge

All kWh: $0.02000/kWh

Power Supply Service (Optional)

Energy Charge	*Capacity*	*Non-Capacity*	*Total*
All kWh:	*$0.02583*	*$0.07047*	$0.09630/kWh

For new customers the company may, at its discretion, waive the three month qualification period when, in the company's judgment, the customer would obviously meet the qualification criteria. Within 12 months, the company shall inform the customer in writing that failure of the customer to meet the qualification criteria after a waiver is granted will result in:

1. The customer being immediately placed on the appropriate rate schedule, and
2. Backbilling to reflect the appropriate rate schedule from the date the waiver was originally effective.

MINIMUM CHARGE

For the regular rate, the minimum charge is the fixed charge plus the energy optimization charge.

POWER SUPPLY COST RECOVERY CLAUSE — See Schedule PSCR starting on Sheet D-100.00

SHORT TERM SERVICE — See Schedule CgXM starting on Sheet D-109.00

ANNUAL MINIMUM CHARGE — See Schedule CgXM starting on Sheet D-109.00

SEASONAL BILLING — See Schedule CgXM starting on Sheet D-109.00

SPACE HEATING — See Schedule CgXM starting on Sheet D-110.00

(Continued on Sheet No. D-112.00)

D3. SMALL COMMERCIAL & INDUSTRIAL SERVICE **Cg-3M**

AVAILABILITY

This schedule is available to small commercial and industrial customers where:

1. Total monthly energy consumption has exceeded 12,500 kWh for three consecutive months and, after qualifying at least once in succeeding rolling 12 month periods; or
2. Does not meet the availability criteria for the Cg-1M or Cp-1M rate schedules.

Customers taking service on the Cg-1M rate as of the effective date of the Commission Order in Case U-13688, that qualify for CP-1M by exceeding 100 KW of demand or 25,000 kWh for three consecutive months prior to September 1, 2004, have the option to remain on the applicable energy only rate. These customers will be subject to the following customer charges:$255.00/month or $8.3836/day for year-round customer charge or a $510/month or $16.7671/day seasonal customer charge.

This schedule is available to customers who are not required to take service under the Power Supply Default Service (PSDS). Customers taking service under the Retail Access Service Tariff (RAST) shall be responsible for the Distribution Charges but not the Power Supply Charges under this rate schedule. Customers that purchase power supply service from the Company shall be subject to both the Distribution and Power Supply charges contained in this rate schedule.

MONTHLY RATE

Distribution Service

Fixed Charge

Daily	Monthly	
$1.3151	$40.00	Year-Round Customers
$2.6301	$80.00	Seasonal Customers

Energy Charge

All kWh: $0.01335/kWh

Power Supply Service (Optional)

Energy Charge	*Capacity*	*Non-Capacity*	*Total*
All kWh:	***$0.03210***	***$0.07063***	$0.10273/kWh

For new customers the company may, at its discretion, waive the three month qualification period when, in the company's judgment, the customer would obviously meet the qualification criteria. Within 12 months, the company shall inform the customer in writing that failure of the customer to meet the qualification criteria after a waiver is granted will result in:

1. The customer being immediately placed on the appropriate rate schedule, and
2. Backbilling to reflect the appropriate rate schedule from the date the waiver was originally effective.

MINIMUM CHARGE

The minimum charge is the fixed charge plus the energy optimization charge.

POWER SUPPLY COST RECOVERY CLAUSE — See Schedule PSCR starting on Sheet D-100.00

SHORT TERM SERVICE — See Schedule CgXM starting on Sheet D-109.00

ANNUAL MINIMUM CHARGE — See Schedule CgXM starting on Sheet D-109.00

SEASONAL BILLING — See Schedule CgXM starting on Sheet D-109.00

SPACE HEATING — See Schedule CgXM starting on Sheet D-110.00

WATER HEATING — See Schedule CgXM starting on Sheet D-110.00

(Continued on Sheet No. D-114.00)

D3. SMALL COMM & IND SERVICE – OPTIONAL TIME-OF-USE Cg-OTOU-1M

AVAILABILITY

This schedule is available upon written request on a voluntary basis for service to small commercial and industrial customers who qualify for rate Schedules Cg-1M, Cg-2M, Cg-3M, or Cg-4M. Optional Power Supply Service is available only to Customers not taking power supply service under rate schedule RAST and not required to receive service under rate schedule PSDS.

Customers taking service on the Cg-OTOU-1M rate as of the effective date of the Commission Order in Case No. U-13688, that qualify for CP-1M by exceeding 100 KW of demand or 25,000 kwh for three consecutive months prior to September 1, 2004, have the option to remain on the applicable energy only rate. These customers will be subject to the following customer charges:$255.00/month or $8.3836/day for year-round customer charge or a $510/month or $16.7671/day seasonal customer charge.

This schedule is available to customers who are not required to take service under the Power Supply Default Service (PSDS). Customers taking service under the Retail Access Service Tariff (RAST) shall be responsible for the Distribution Charges but not the Power Supply Charges under this rate schedule. Customers that purchase power supply service from the Company shall be subject to both the Distribution and Power Supply charges contained in this rate schedule.

MONTHLY RATE

Distribution Service

Fixed Charge

Daily	Monthly	
$0.8219	$25.00	Year-round customers
$1.6438	$50.00	Seasonal customers

Energy Charge

On-Peak: All kWh at ***$0.03700***
Off-Peak: All kWh at ***$0.00925***

Power Supply Service (Optional)

Energy Charge	*Capacity*	*Non-Capacity*	*Total*
On-Peak: All kWh at	***$0.09829***	***$0.11621***	$0.21450
Off-Peak: All kWh at		$0.05362	

PRICING PERIOD DEFINITIONS

On-Peak Periods

The following periods on Monday, Tuesday, Wednesday, Thursday, and Friday, excluding holidays:

1. Summer (Calendar Months of May - September)
   Option 1: 9:00 AM to 7:00 PM
   Option 2: 10:00 AM to 8:00 PM
2. Winter (Calendar Months of October - April)
   Option 1: 8:00 AM to 12:00 noon and 4:00 PM to 9:00 PM
   Option 2: 9:00 AM to 12:00 noon and 4:00 PM to 10:00 PM

Customer must choose the same option number during both the winter and summer periods.

Off-Peak Periods

All hours not included as on-peak hours above.

HOLIDAYS

The days of the year which are considered holidays are New Year's Day, Good Friday, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, Friday After Thanksgiving, Day Before Christmas, Christmas Day, and Day Before New Year's Day.

(Continued on Sheet No. D-116.00)

D4. LARGE COMMERCIAL & INDUSTRIAL SERVICE **Cp-1M**

EFFECTIVE IN: All territory served.

AVAILABILITY

This schedule is applicable to customers whose monthly demand is equal to or greater than 100 kW or 25,000 kWh/month for three consecutive months and others taking standby service. This schedule is also available to small commercial and industrial customers who contract for service under the Cp-I2M Interruptible Rider. This service is not available for customers required to take service under the Power Supply Default Service. Customers taking service under the Retail Access Service Tariff (RAST) shall be responsible for the Distribution Charges but not the Power Supply Charges under this rate schedule. Customers that purchase power supply service from the Company shall be subject to both the Distribution and Power Supply charges contained in this rate schedule.

The transmission rates are available to customers that take service directly from a company-owned substation (i.e. Company owns no distribution facilities downstream of substation). For customers that meet this condition, a monthly charge of $0.49/kVA of installed substation transformer capacity as determined by the company shall apply.

MONTHLY RATE

Distribution Service	Secondary	Primary	Transmission
Fixed Charge:			
Monthly	***$142.00***	***$673.00***	***$990.00***
Daily	***$4.6685***	***$22.1260***	***$32.5479***
Demand Charge			
1. Customer Demand:$/kW	$2.95	$2.22	$0.00
Per KW of maximum demand during the current and preceding 11 months, plus,			
2. On-Peak Demand			
a. Winter (Oct-May): $/kW	$1.14	$1.14	$1.14
10:00 AM to 8:00 PM; Monday through Friday (except holidays)			
b. Summer (Jun-Sep): $/kW	$1.14	$1.14	$1.14
10:00 AM to 11:00 PM; Monday through Friday (except holidays)			

Power Supply Service (Optional)	Secondary	Primary	Transmission
On-Peak Demand			
a. Winter (Oct-May):$/kW			
10:00 AM to 8:00 PM; Monday through Friday (except holidays)			
Capacity	***$7.50***	***$7.33***	***$7.23***
Non-Capacity	***$5.40***	***$5.28***	***$5.21***
Total	$12.90	$12.61	$12.44
b. Summer (Jun-Sep):$/kW			
10:00 AM to 11:00 PM; Monday through Friday (except holidays)			
Capacity	***$7.50***	***$7.33***	***$7.23***
Non-Capacity	***$5.40***	***$5.28***	***$5.21***
Total	$12.90	$12.61	$12.44

Energy Charge	Secondary	Primary	Transmission
1. On-Peak			
a. Winter (Oct-May):$/kWh	$0.06197	$0.06017	$0.05942
6:00 AM to 10:00 PM; Monday through Friday (except holidays)			
b. Summer (Jun-Sep):$/kWh	$0.06197	$0.06017	$0.05942
7:00 AM to 11:00 PM; Monday through Friday (except holidays)			
2. Off-Peak			
a. Winter (Oct-May):$/kWh	$0.03350	$0.03253	$0.03212
10:00 PM to 6:00 AM; Monday through Friday, all day Saturday, Sunday, and holidays			
b. Summer (Jun-Sep):$/kWh	$0.03350	$0.03253	$0.03212
11:00 PM to 7:00 AM; Monday through Friday, all day Saturday, Sunday, and holidays			

Note: For a 10:00 PM change between on peak and off peak time periods in the Winter months, on peak consumption will be recorded through 10:00 PM. Off Peak consumption will begin at 10:00:01 PM as recorded by the meter.

(Continued on Sheet No. D-120.00)

Issued April 11, 2017
T. T. Eidukas
Vice-President,
Milwaukee, Wisconsin

Effective for service rendered on and after April 24, 2017

Issued under authority of the Michigan Public Service Commission dated April 23, 2015 in Case No. U-17669

D6. MUNICIPAL POWER-SEWAGE DISPOSAL & WATER PUMPING Mp-1M

EFFECTIVE IN All territory served.

AVAILABILITY

This schedule is available for operation of sewage disposal systems and water pumping systems. This schedule is available to customers who are not required to take service under the Power Supply Default Service (PSDS). Customers taking service under the Retail Access Service Tariff (RAST) shall be responsible for the Distribution Charges but not the Power Supply Charges under this rate schedule. Customers that purchase power supply service from the Company shall be subject to both the Distribution and Power Supply charges contained in this rate schedule.

MONTHLY RATE

Distribution Service

Customer Charge

Daily	Monthly
$1.6438	$50.00

Energy Charge

All kWh:	$0.01471

Power Supply Service (Optional)

Energy Charge	*Capacity*	*Non-Capacity*	*Total*
All kWh:	***$0.02727***	***$0.05993***	***$0.08720***

MINIMUM CHARGE

The monthly minimum charge is the fixed charge plus the energy optimization charge.

POWER SUPPLY COST RECOVERY CLAUSE

See Schedule PSCR.

SPECIAL RULES

1. Each metering point shall be billed as a separate customer.

2. The entire energy requirements for each meter point shall be supplied by the company, except such energy that the customer may generate from sewage gas and such power that the customer may supply in case of failure of the service supplied by the company.

ENERGY OPTIMIZATION: See Schedule EO starting on Sheet No. D-156.00

D7. OUTDOOR OVERHEAD LIGHTING SERVICE – COMPANY-OWNED Ls-1M

EFFECTIVE IN All territory served.

AVAILABILITY

Facilities in this section are available to all classes of customers who desire company owned lighting service.

NON-CAPACITY MONTHLY RATE

Fixture Type	Lamp Type	Lumens	Watts	$/Month
Cobra Head	Sodium Vapor	9,000	100	***$10.32***
Cobra Head	Sodium Vapor	14,000	150	***$11.52***
Cobra Head	Sodium Vapor	27,000	250	***$14.15***
Cobra Head	Sodium Vapor	45,000	400	***$19.85***
Area-Power Bracket	Sodium Vapor	9,000	100	***$9.59***
Area-Power Bracket	Sodium Vapor	14,000	150	***$12.83***
Directional-Flood	Sodium Vapor	27,000	250	***$19.61***
Directional-Flood	Sodium Vapor	45,000	400	***$23.47***
Directional-Flood	Metal Halide	36,000	400	***$23.46***
Directional-Flood	Metal Halide	110,000	1,000	***$42.50***

Capacity Energy Charge: ***$0.02294/kWh***

The above charges are for lighting standard facilities on existing company-owned distribution poles. The company will own and install the standard facilities.

If the non-standard facilities shown below are requested, the customer has the option to pay the charges upfront or pay the monthly charges shown below. These charges are in addition to the monthly rates shown above.

Non-Standard Facilities	Monthly Charge
Galvanized Mast Arm in excess of 6 feet	$0.14 / ft
Additional Wood Pole (30', 35' or 40')*	$3.09 / pole
Span of Conductor	$1.44 / span

* The additional wood pole charges shall apply to fixtures that cannot be attached to an existing company pole. Street lights installed for governmental authorities under the Ms-1M rate schedule prior to April 1, 2015, are exempt from the exclusive use wood pole charges.

ORNAMENTAL FACILITIES

The Company offers specific Company-owned ornamental lighting facilities that are available to all customers under a special contract.

The customer is obligated to make a special facilities payment upon installation of the facilities equal to:

a. the "cost difference" between the cost of the ornamental facilities and cost of the standard lighting facilities, and
b. a payment in advance for maintenance equal to 24% of the "cost difference" payment above for ornamental facilities.

If for any reason a lighting system must be replaced or renovated after the end of the contract, the customer shall be responsible for all associated charges. Replacement or renovation of lighting units and their major components after the contract period is at the discretion of the Company and may require a new lighting contract/agreement between the Company and the customer.

If at any time a customer requests a replacement or maintenance by the Company of an ornamental lighting facility for aesthetic reasons, the customer will be required to pay time and materials for the work. If the item in question falls under the manufacturer's warranty the Company will work with the customer and the manufacturer to receive the replacement item. The Company will however charge for labor and any other materials needed for replacement. The Company reserves the right to determine if replacement or maintenance will be done.

(Continued on Sheet No. D-133.00)

D7. OUTDOOR OVERHEAD LIGHTING SERVICE – CUSTOMER-OWNED (CLOSED) **Ls-1M**
(Continued from Sheet No. D-133.00)

AVAILABILITY

Facilities in this section are available to municipal customers who desire customer owned lighting service. This option is closed to new customers effective January 1, 2015.

NON-CAPACITY MONTHLY RATE

Fixture Type	Lamp Type	Lumens	Watts	$/Month
Cobra Head	Sodium Vapor	9,000	100	*$ 7.26*
Cobra Head	Sodium Vapor	14,000	150	*$ 7.69*
Cobra Head	Sodium Vapor	27,000	250	*$10.12*
Cobra Head	Sodium Vapor	45,000	400	*$13.59*
LED	LED	9,000*	100*	*$ 5.66*
LED	LED	14,000*	150*	*$ 8.20*
LED	LED	27,000*	250*	*$10.74*
LED	LED	45,000*	400*	*$13.27*

Capacity Energy Charge: ***$0.02267/kWh***

*The wattages and lumens listed under the LED lamps are wattages and lumens of sodium vapor lamps to which the LED lamps are considered equivalent. Actual wattages and lumens of LED lamps may vary.

TERMS AND PROVISIONS

Customer Owned Lighting Systems

1. Service Rules
   a) The customer shall own the system, including switching equipment and the connecting cable to the Company's system.
   b) Systems must be of a design and in a condition satisfactory to the Company.
   c) Replacement of customer owned equipment, otherwise called out in the maintenance section, shall be at the expense of the customer.
   d) The system may be served by either multiple or series type circuits as agreed upon between the customer and the Company.
   e) The customer must make the Company aware of any changes the customer makes to poles and fixtures after initial installation. This includes but is not limited to changes in location and wattage.
   f) Additional Service rules listed on Sheet D-135.00.

2. Extension Of Service

   Additional lights will be served at any location designated under the same rates, terms, and conditions, provided the additional units are not more expensive for the Company to operate and maintain.

3. Maintenance
   a) The following items are considered normal maintenance of customer owned ornamental lighting and will be replaced or maintained at Company expense within the contract:
      i.) Underground and/or overhead cables: All breaks or open circuits except those caused by accidents, improper installation, foreign digging operations or deterioration due to aging and/or absorption of moisture. Deterioration due to aging is to be determined by the Company.
      ii.) Ballasts, luminaires, photo electric controls, lamps, refractors and relays that the company normally stocks for standard systems. The customer shall be responsible for any repairs (including parts and labor) of equipment after the expiration of the contract.
      iii.) The acquisition of repair and maintenance items and the cost of items which the Company does not consider standard facilities shall be the responsibility of the customer. The labor to replace this failed equipment is included in the monthly rates.

(Continued on Sheet No. D-135.00)

Sum of Capacity Revenue Requirements	$	81,895,243	
Sum of 12 CP Averages		357	MW
Capacity Charge	$	229,523	MW/Year
	$	629	MW/Day

P R O O F O F S E R V I C E

STATE OF MICHIGAN)

Case No. U-18253

County of Ingham)

Lisa Felice being duly sworn, deposes and says that on November 30, 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).

Lisa Felice

Lisa Felice

Subscribed and sworn to before me
this 30th day of November 2017

Steven J. Cook

Steven J. Cook
Notary Public, Ingham County, Michigan
As acting in Eaton County
My Commission Expires: April 30, 2018

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Updated 8-18-2017

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