

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of INDIANA)	
MICHIGAN POWER COMPANY for authority)	
to increase its rates for the sale of electric energy)	Case No. U-18370
and for approval of depreciation accrual rates and)	
other related matters.)	
_____)	

At the April 12, 2018 meeting of the Michigan Public Service Commission in Lansing,
Michigan.

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

ORDER

I. HISTORY OF PROCEEDINGS

On May 15, 2017, Indiana Michigan Power Company (I&M) filed an application seeking authority to increase its rates for the sale of electric energy, approval of depreciation accrual rates, and other related matters. The rate increase sought in this proceeding is based on the company's projections for relevant items of investment, expenses, and revenues for a test year covering the calendar year ending December 31, 2018. In its application, I&M averred that, without rate relief, the company will experience a jurisdictional electric revenue shortfall of \$51,700,000, on an annual basis, during the test year.

On August 25, 2017, the Association of Businesses Advocating Tariff Equity (ABATE) filed a motion alleging that I&M had significantly amended its application to correct an error associated

with the company's power supply cost recovery (PSCR) revenues. Pursuant to MCL 460.6a(5) and several court and administrative rules, ABATE requested that certain exhibits be stricken from the record, the case schedule be extended, or, in the alternative, the company's application be dismissed. In response, I&M denied that it significantly amended its application, explaining that its requested revenue requirement remains the same and that it still "supports a \$61.4 million increase, as described in I&M's testimony and exhibits, and an ultimate request for a \$51.7 million increase, as stated in the Application." I&M's August 29, 2017 Answer to ABATE's Motion to Strike, Extend the Schedule, or Alternative Relief, p. 7. To resolve the concerns set forth in ABATE's motion, on September 6, 2017, the parties signed a stipulation stating that, among other things, I&M would limit its proposed rate increase to \$51,700,000, which is discussed in further detail on pages 60-61 of this order.

I&M's current base rates were approved in an order approving a settlement agreement issued on February 15, 2012, in Case No. U-16801. The company explained that the "Key factors contributing to this needed increase in I&M's electric revenue requirements include revenue requirement changes related to (i) rate base; (ii) depreciation rates; (iii) sales forecasts; (iv) operation and maintenance (O&M) expense; and (v) other expenses, including amortization and recovery of certain deferred assets." Application, p. 4.

In its application, I&M proposed establishing a new PSCR basing point in its base rates, updating and continuing the rate realignment surcharge/credit, and revising the depreciation accrual rates to account for net additions to rate base, the expected service life for Rockport Unit 1, the expected service life of the company's automatic meter reading (AMR) technology, and other factors. I&M also requested accounting authority to establish regulatory assets to defer unrecovered costs related to low-income customer rates and Cook Plant dry cask storage. *Id.*, p. 5.

Further, I&M requested over/under accounting authority associated with the net lost revenue (NLR) tracker and low-income cost recovery surcharge tracker. I&M proposed establishing regulatory liabilities/assets for actual costs below or above test year baseline O&M costs for distribution vegetation management and distribution major storms. Finally, I&M consolidated two rate schedule tariff sheets into a new General Service rate schedule, canceled several tariffs to create a new NLR tracker surcharge and economic development rider (EDR), and made changes to its terms and conditions of service and tariff book.

I&M proposed that the rates established in this case include an authorized rate of return (ROR) on common equity (ROE) of 10.60% and reflect an overall ROR on total rate base of 6.02%. The company asserted that its “requested overall rate of return is the minimum necessary to enable I&M to attract, at a reasonable cost, the capital which is required to maintain its property in good operating condition, to construct its required new facilities and to continue to provide safe, adequate and dependable service to its Michigan jurisdictional customers.” *Id.*, p. 6.

I&M stated that its proposed rate schedules were designed using jurisdictional and class cost-of-service studies (COSS) that are based on cost-based rates. However, the company noted that the COSS demonstrates that some classes are currently being subsidized by others. As a result, I&M claimed, the company designed its rates to gradually eliminate those subsidies.

According to I&M, the net impact of all matters to be considered in this proceeding supports the company’s requested rate relief of \$51,700,000. The company maintained that, absent rate relief in this amount, it will experience revenues so low as to deprive it of a reasonable return on its investments in violation of the federal and state constitutions.

Administrative Law Judge Mark E. Cummins (ALJ) held a prehearing conference on June 22, 2017. At the prehearing conference, the ALJ granted petitions to intervene filed by the Michigan

Department of the Attorney General (Attorney General) and ABATE. The Commission Staff (Staff) also participated.

An evidentiary hearing was held on November 15, 2017, after which timely briefs and reply briefs were filed. On February 8, 2018, the ALJ issued his Proposal for Decision (PFD). The parties filed exceptions to the PFD on February 26, 2018, and replies to exceptions on March 8, 2018. The record consists of 1,285 pages of transcript and 217 exhibits received into evidence.¹

On December 27, 2017, the Commission issued an order in Case No. U-18494 (December 27 order), directing all rate-regulated utilities to implement regulatory accounting to address the financial effects of the Tax Cuts and Jobs Act of 2017 (TCJA). In addition, the Commission requested comments from regulated utilities on “the extent of the impacts of the new law, and how any resulting benefit should flow back to ratepayers.” December 27 order, p. 2. Utilities, including I&M, were ordered to file initial comments by January 19, 2018, and interested parties were asked to file reply comments by February 2, 2018. The Commission addresses the application of the TCJA to I&M’s revenue requirement *infra*.

II. UNCONTESTED ISSUES

On page 4 of the PFD, the ALJ stated that the parties resolved the following issues, which were not presented in their briefs:

1. The removal of the Rockport Unit 2’s construction work in progress (CWIP) with regard to its potential installation of a selective catalytic reduction (SCR) system, which is discussed below;
2. Proposed cost levels for “Other Tax,” the “Allowance for Funds Used During Construction” (AFUDC) for project-related expenditures, and two Working Capital account levels that had slight differences among the parties;

¹ The ALJ provided a detailed review of the record and positions of the parties, which will only be repeated as necessary to discuss an issue in contention.

3. I&M's assertion that, at least for the test year in question, its Accumulated Provision for Depreciation would be \$2.844 billion on a company-wide basis, which translates into \$425,729,867 on a Michigan-only jurisdictional basis;
4. Various cost of capital issues such as capital structure, most costs rates (as well as the methodology for determining them) for various balances, with the significant exception regarding the appropriate cost of equity, among other, smaller items;
5. The accumulated provision for depreciation for the projected test year (in the amount of \$425,729,867 on a Michigan jurisdictional basis);
6. Customer Service and Administrative O&M expenses as reflected as "Other O&M Expenses" in Exhibit IM-19;
7. Numerous tariff provisions, including the implementation of an Economic Development Rider (EDR) and a low-income cost recovery surcharge.

The ALJ also noted that the proposed level of accumulated depreciation would need to be adjusted based on any changes to rate base that are ultimately approved by the Commission.

III. TEST YEAR

I&M proposed using the 12-month period ending December 31, 2018, as the test period for establishing representative levels of revenues, expenses, rate base, and capital structure for use in setting rates. The ALJ noted that none of the parties objected to I&M's proposed 12-month time frame or the company's use of historical January 2017 data, which was adjusted to reflect updated projections of investments through the end of 2018. Therefore, the Commission adopts the calendar year ending December 31, 2018, as the test period for setting rates.

IV. RATE BASE

A utility's rate base consists of the capital invested in used and useful plant, plus the utility's working capital requirements, less accumulated depreciation. I&M projected a jurisdictional rate base of \$1,007,450,000 and the Staff calculated a jurisdictional rate base of \$984,196,000. The Attorney General advocated a downward adjustment of \$2,100,000 to the company's rate base, and ABATE argued that I&M's proposed depreciation rates should be denied. After making

adjustments, discussed in more detail below, the ALJ recommended a jurisdictional rate base of \$984,631,000.

A. Uncontested Rate Base Issues

The parties did not dispute I&M's proposed expenditures for the following items: nuclear generation capital, distribution capital for risk mitigation, and the jurisdictional deferred gain on the sale of Rockport Unit 2. The ALJ recommended that the Commission adopt the company's proposed expenditures and no exceptions were filed. Therefore, the Commission finds that the ALJ's findings and conclusions on these issues are reasonable and prudent and should be adopted.

B. Net Utility Plant

1. Contingency Costs

The Staff asserted that I&M failed to include exact numbers for its contingency expenditure levels and, despite requests by the Staff, no contingency figures were ever provided. As a result, the Staff performed its own contingency calculation and determined that 10% was a reasonable estimate because, "in prior electric rate cases, other Michigan utilities used contingency projections that were greater than ten percent." 3 Tr 1144. Therefore, the Staff requested that the Commission disallow contingency costs totaling \$4,720,000, for various capital expense items. The Attorney General agreed with the Staff.

I&M argued that contingency costs are essential to the company's ability to manage its overall capital portfolio. I&M explained that its contingency projection is not mere speculation, but a best industry practice to establish a reserve based on a review of the specific risk of each particular project. In the company's opinion, "contingency should be distinguished from 'management reserve,' which is used to cover 'unknown' risks that may be incurred on a project." I&M's reply brief, pp. 5-6.

The ALJ agreed with the Staff and the Attorney General, finding I&M's arguments unpersuasive. Regarding I&M's contention that contingency costs are a standard project management practice, the ALJ determined that project management and rate recovery are not the same: the company may budget and spend contingency funds, but I&M cannot recover the funds from ratepayers until it can show that the funds were actually spent and were reasonable and prudent. And, notably, the ALJ found that I&M did not provide "specific details for any of the projects to which those requested contingency expenditures relate." PFD, p. 28.

I&M excepts, noting that MCL 460.6a(1) authorizes the use of a future projected test year based on projected costs. In the company's opinion, "The argument that the Company should not be permitted to recover reasonably projected contingency costs until the costs have been actually incurred and are known for certain is contrary to the legislative intent of MCL 460.6a(1)" and conflicts with past Commission orders interpreting the statute. I&M's exceptions, p. 25, citing January 25, 2010 order in Case No. U-15645. Responding to the Staff's and the ALJ's claim that the company failed to include specific contingency costs, I&M asserts that it provided credible witness projections for cybersecurity expenses and that the Staff agreed that the company's cybersecurity investments are "necessary and prudent at this time." I&M's exceptions, p. 25, quoting 3 Tr 1192. Thus, I&M argues, the ALJ's recommendation to reject the company's proposed cybersecurity contingency expenses is erroneous because it is not supported by the record, but instead was based on "unsupported speculation about hypothetical scenarios." I&M's exceptions, p. 25. I&M also contends that the ALJ's recommendation that the company verify expenditures prior to rate recovery requires the company to engage in unlawful retroactive ratemaking.

In replies to exceptions, the Staff disagrees that, pursuant to Michigan law, the Commission must accept the company's projected costs. Rather, the Staff argues that, according to MCL 460.6a(1), a utility *may* use projected costs—there is no requirement that utilities *must* use a projected test year. The Staff affirms that, “certainly, there is no requirement that the Commission rely exclusively on information from the projected test year when setting rates.” Staff’s replies to exceptions, p. 5. Conversely, the Staff asserts, there is nothing preventing the Commission from relying on historical information to establish rates.

The Staff also objects to I&M’s recovery of contingency costs, reiterating that it is inappropriate for the company to “earn depreciation and return on these expenditures because 1) they may not be incurred at all, and 2) if they are incurred, the final amount could be far less than projected.” *Id.* The Staff again notes that the Commission has excluded contingency costs in the several recent rate cases.

The Commission agrees with the ALJ that I&M’s projected contingency costs, as calculated by the Staff, should be disallowed. As the Commission has found repeatedly, while allowing for contingency costs may be appropriate in project planning, the inclusion of these costs in customer rates is not reasonable. *See*, March 29, 2018 order in Case No. U-18322, p. 11; November 19, 2015 order in Case No. U-17735, pp. 7-11; December 11, 2015 order in Case No. U-17767 (December 11 order), pp. 19-20; December 9, 2016 order in Case No. U-17999, pp. 4-6; January 31, 2017 order in Case No. U-18014 (January 31 order), p. 12; and February 28, 2017 order in Case No. U-17990 (February 28 order), pp. 11-12. The inclusion of contingency costs allows the utility to receive a return of and on those costs to the detriment of ratepayers who may never benefit at all. In addition, if ratepayers were required to bear this risk, there would be no incentive for the utility to minimize projected contingency costs, but every incentive to inflate them.

The Commission notes that I&M did not include specific amounts for contingency costs and failed to respond to the Staff's requests for additional information. Without the ability to verify the company's projected contingency expenses, the Staff had to perform its own contingency calculation and determined that 10% was a reasonable estimate because, in other electric rate cases, Michigan utilities used contingency projections that were 10% or more. The Commission finds the Staff's rationale reasonable and adopts its calculation. For these reasons, as well as those the Commission articulated in its previous orders, the Commission reaffirms its determination and disallows projected contingency costs totaling \$4,720,000. In future rate cases, I&M shall clearly delineate the amounts set aside for contingency as described in the Rate Case Filing Requirements approved on July 31, 2017 in Case No. U-18238.

2. Fossil and Hydro Generation and Related Environmental Expenditures

I&M stated that its fossil and hydro generating fleet includes the coal-fired Rockport Plant and six run-of-the-river hydro facilities. According to the company, the forecasted capital investments for the 10 "Major Projects," explained in greater detail in testimony and briefing, include the installation of air quality control systems at Rockport Units 1 and 2, the upgrade of selected equipment at Rockport Units 1 and 2 and the Elkhart hydro plant, and updates to pollution control systems to comply with the United States Environmental Protection Agency (EPA) rules. *See*, I&M's initial brief, pp. 19-21. For these Major Projects, I&M projected capital expenditures of \$75,487,000 for 2017 and \$63,213,000 for 2018. The company stated that it also plans to spend \$14,577,000 in 2017 and \$22,655,000 in 2018 for "Other Capital Investment," which I&M described as multiple smaller projects that "represent the type of continuous investment that is necessary to maintain the availability and reliability of the generating units." *Id.*, pp. 18-19.

The Staff requested that the Commission disallow expenses for the installation of an SCR system at Rockport Unit 2 because I&M and several of its affiliated companies are “requesting that the U.S. District Court for the Southern District of Ohio modify the Consent Decree [with the EPA]. . . . to delete the requirement that SCR be installed on Rockport Unit 2 by December 31, 2019.” 3 Tr 1148. The Staff contended that, if the modification is adopted, I&M will not need to spend the total forecasted amounts for SCR at Rockport Unit 2. Therefore, the Staff recommended that the Commission disallow \$3,276,690 for 2017 and \$7,511,065 for 2018.

In the Attorney General’s opinion, I&M failed to provide convincing evidence that Rockport Unit 1 will remain in service until 2044, the year in which the company originally claimed the unit would retire. According to the Attorney General, I&M supplied evidence indicating that the depreciation rates for Rockport Unit 1 will be accelerated through 2028 and that the lease for Rockport Unit 2 may not be renewed in 2022. Thus, he argued that equipment upgrades at Rockport Units 1 and 2 may be unnecessary due to early retirement of the units. And, in regard to the discrepancy in potential retirement dates, the Attorney General asserted that I&M did not perform adequate benefit/cost analyses or provide related work papers to justify the company’s spending on five equipment-upgrade projects. Consequently, he recommended a \$2,100,000 disallowance.

ABATE argued that I&M significantly overstated the depreciation rates for the Rockport units, resulting in a substantial increase in annual depreciation expense for ratepayers. ABATE asserted that the proposal contains errors, it does not reflect the time value of money, and the decommissioning costs include percentage adders that artificially inflate cost estimates. In addition, ABATE contended that there is scant evidence supporting the early retirement of Rockport Unit 1. Therefore, ABATE requested that the Commission should reject the Staff’s

assumption that Rockport Unit 2 will be prematurely retired in tandem with Unit 1 and deny the Staff's proposal to accelerate depreciation rates.

As an initial matter, the ALJ noted that I&M agreed to the Staff's recommendation to remove from CWIP the 2017 and 2018 SCR costs for Rockport Unit 2.

The ALJ recommended that the Commission reject the Attorney General's proposed disallowance. The ALJ stated that it is impractical and unprecedented to require a formal benefit/cost analysis for all of I&M's generation-related capital expenditures. In addition, the ALJ found that I&M provided benefit/cost analyses for three Major Projects that were "reasonable and reliable and were appropriately based on information known to the Company" when they were performed. PFD, pp. 12-13, quoting 3 Tr 247. The ALJ noted that none of the parties offered evidence contradicting the analyses or provided any competing analyses.

In response to ABATE's concern regarding depreciation rates, the ALJ found persuasive the company's claim that "the shortening of the active lives of its Rockport Units, as well as increasing the amount spent to keep Cook open (which is addressed below), is due to 'external pressures [that are making] regulatory, economic, and technological issues' beyond the Company's control alter the facilities' initially-expected operating lives." PFD, p. 14, quoting I&M's reply brief, p. 2. Thus, the ALJ recommended that the Commission reject ABATE's position on this issue.

Therefore, with the exception of the SCR costs for Rockport Unit 2 discussed above, the ALJ recommended that the Commission adopt I&M's proposed fossil and hydro generation expenditures for 2017 and 2018.

The Attorney General excepts, reiterating that I&M failed to provide convincing evidence that the Rockport units will remain used and useful until 2040 and, therefore, it is imprudent to

accelerate depreciation rates or perform equipment upgrades. He argues that, “At the very least, when justifying the installation of the dry sorbent injection (DSI) and Rockport Unit 1 SCR systems, the Company should have performed analyses in which the Rockport units were retired earlier than 2040 after the installation of the DSI and SCR systems.” Attorney General’s exceptions, p. 10. According to the Attorney General, if the Commission adopts the ALJ’s recommendation, I&M will be permitted to invest in environmental technology that may quickly become obsolete and the company will also receive the benefit of accelerated depreciation rates, all at the expense of ratepayers.

Regarding the five equipment-upgrade projects to which he objected, the Attorney General asserts that his “expert was unable to fully evaluate the cost/benefit analysis performed by the Company . . . because the Company did not retain the spreadsheet analyses with all formulas intact, nor did the Company provide all data and assumptions used in the analyses.” Attorney General’s exceptions, p. 13 (notes omitted). As a result, he argues, I&M failed meet its burden of proving by a preponderance of the evidence that the proposed expenditures are reasonable and prudent for those five projects.

In exceptions, ABATE asserts that the ALJ did not adequately address its objections to I&M’s proposed depreciation rate increase. Accordingly, if the Commission fails to address these issues, ABATE contends that ratepayers will pay higher-than-necessary depreciation rates, for a total over-payment of more than \$20,000,000.

I&M replies that the Attorney General incorrectly assumes that the company’s capital expenditures for Rockport environmental systems are not reasonable or prudent. I&M avers that these specific environmental technology investments are required by the consent decree with the EPA and are supported by economic analyses submitted with the company’s certificate of public

convenience and necessity (CPCN) application in Indiana.² And, I&M states, the company's analyses show that the DSI and Rockport Unit 1 environmental systems are economical, even with an earlier retirement date of 2028.

I&M also objects to the Attorney General's request that the Commission disallow the costs associated with several Major Projects because, allegedly, the company failed to provide benefit/cost analyses for the five projects that exceed \$1 million. As stated in its initial brief, I&M contends that a formal benefit/cost analysis for each generation capital expenditure is impractical, unprecedented, and unnecessary. The company maintains that it provided sufficient testimony, evidence, and benefit/cost analyses to support the capital expenditures for the Major Projects.

The company argues that the ALJ provided a reasoned analysis in rejecting ABATE's position. I&M disputes that the decommissioning costs for Rockport Unit 1 and the hydro facilities contain adders that inflate the cost. I&M asserts that the adders are appropriate because power plants change over time, the company must add retrofitted infrastructure and equipment, and there is an uncertainty to demolition costs.

Regarding ABATE's request for a time-value-of-money adjustment, I&M responds that "This assertion is at odds with straight-line depreciation principles and fails to take into account how depreciation is treated in the ratemaking process." I&M's replies to exceptions, p. 20. I&M explains that straight-line depreciation evenly allocates costs over time, whereas ABATE's position discounts future costs, which merely provides the current value of future costs.

Addressing other purported errors, I&M argues that ABATE: (1) misunderstands the process by which interim retirement rates are calculated; (2) erroneously claims that the company did not

² May 13, 2015 order, Cause No. 44523, Indiana Utility Regulatory Commission.

properly apply the inflation rate to demolition costs; and (3) incorrectly assumes that I&M miscalculated the net salvage ratio.

On page 13 of its replies to exceptions, ABATE agrees with the Attorney General that I&M's "reasons for seeking to change its depreciation rates for Rockport Units 1 and 2 are questionable." Additionally, ABATE states that the company's reasons for adjusting the depreciation rates are stale and lack sufficient justification.

The Commission finds the ALJ's findings and conclusions to be reasonable and prudent. As initially noted by the ALJ, I&M and the Staff agreed that the SCR costs of \$3,276,690 for 2017 and \$7,511,065 for 2018 for Rockport Unit 2 should be removed from CWIP and, therefore, the Commission adopts this adjustment.

With the exception of the SCR costs associated with Major Project 7, discussed above, the Commission approves I&M's proposed expenditures for the 10 Major Projects. The Commission finds that the company provided persuasive testimony explaining that the expenditures are necessary to improve safety, efficiency, and reliability, to reduce outages, and, for some projects, to comply with federal mandates. *See*, 3 Tr 221-224, 231-232, 298-300.

I&M explained that it is bound by a consent decree with the EPA that requires the company to make specified investments in environmental systems at the Rockport Plant. *See*, 3 Tr 80-81, 293-297. In connection with its Indiana CPCN, I&M submitted economic analyses showing that, based on current information, installing DSI and SCR systems at the Rockport Plant would comply with environmental mandates and save ratepayers hundreds of millions of dollars compared to the much more expensive flue gas desulphurization scrubbers.

The Attorney General contends that I&M failed to use an appropriate retirement date for the Rockport Plant in its economic analyses; therefore, the analyses are flawed and the expenses for

the DSI and SCR systems should be disallowed. The Commission disagrees, noting that for Rockport Unit 1, I&M provided an SCR analysis assuming that Unit 1 will retire at the end of 2025. *See*, 3 Tr 320. According to the company's analysis, compared to other options, installing the SCR system at Unit 1 is more economical by tens of millions of dollars. *Id.* And, for the DSI systems at Rockport Units 1 and 2, the company included an analysis that "assumed that the DSI system would only be in service through 2025 for one Rockport Unit and through 2028 for the second Rockport Unit, after which it would be replaced." I&M's replies to exceptions, p. 25; 3 Tr 319. All of the analyses demonstrated sizable economic benefits to ratepayers. Therefore, the Commission finds that the Attorney General's proposed disallowances for the Rockport Plant environmental capital expenditures should be rejected.

Although the Commission expressly values benefit/cost analyses that explain and support utility-requested increased capital expenditures, the Commission agrees with the ALJ that it would be impractical and overly burdensome for I&M to perform benefit/cost analyses for all generation-related capital expenditures, as suggested by the Attorney General.

3. Distribution Capital Expenditures

I&M projected distribution capitalization expenditures of \$36,061,000 for 2017 and \$38,970,000 for 2018. I&M claimed that distribution system issues, including vegetation management problems, are affecting the company's reliability performance. And, because "a large portion of I&M's system is in need of replacement and modernization," the company designed a distribution management plan to improve reliability performance. I&M's initial brief, p. 33, quoting 3 Tr 147. The factors set forth in the company's distribution management program are addressed *ad seriatim*.

a. Vegetation Management

According to I&M, a proactive four-year cycle for vegetation management, as opposed to its current reactive method, would improve system reliability. On page 34 of its initial brief, I&M described the program, claiming that:

Clearance zone widening and cycle-based vegetation management programs are the most effective way to reduce vegetation-related outages. I&M's experience has shown that the four-year average of reliability improvements yields an average reduction in customer minutes of interruption by 68 percent. Conversely, I&M's experience also shows that outages start to increase again after four years without performing vegetation management on a cleared circuit.

* * *

The key benefits for the Company's customers . . . include a positive impact on overall reliability and allowing the Company to restore service to customers more quickly after service interruptions. Additionally, once the cycle-based vegetation management program has been fully implemented, I&M anticipates O&M savings related to a reduction in outages caused by vegetation.

I&M stated that the "clearance zone" would be an initial 15-foot area around the electrical line, which would be subject to capital asset treatment. Then, according to the company, any future vegetation clearing that widens or maintains the area would be an O&M expense. I&M stated that it expects to spend \$8,238,000 in 2017 and \$8,433,000 in 2018 for the program.

I&M also requested permission to establish a deferral account for "actual costs above and below the baseline level of test year vegetation management O&M approved by the Commission." *Id.*, p. 35. The company explained that, through the mechanism, one-twelfth of the baseline test year O&M amount would be compared to the actual expense for the month and the difference recorded as a regulatory liability or asset. I&M stated that the cumulative deferred balance would be addressed, supported, and included in the company's next general rate case.

The Staff objected to I&M's treatment of the "clearance zone" as a capital expenditure. The Staff asserted that, according to a 2013 Federal Energy Regulatory Commission (FERC) audit

report, “the capitalizable costs of equipment,” which “include the first clearing and grading of land and ROW [right of way], only applies to the vegetation management costs incurred for the initial clearing of land during construction. Vegetation management costs that a Company incurs subsequent to the construction phase of a project should be an O&M expense.” 3 Tr 1184, citing Exhibit S-14. The Staff noted that this is consistent with the December 11 order, in which the Commission rejected a similar request from DTE Electric Company (DTE Electric).

The ALJ agreed with the Staff that I&M has “complete control of ‘where, when, and how much it chooses to spend’ on clearing its lines of vegetation, which means that such spending is neither volatile nor a discernable threat to the utility’s financial integrity (notwithstanding I&M’s assertions to the contrary).” PFD, pp. 17-18, quoting the Staff’s reply brief, pp. 9-10. Therefore, the ALJ recommended that the Commission deny the company’s request to capitalize vegetation management expenses of \$16,672,000 for 2017 and 2018.

In addition, the ALJ found I&M’s proposal to use deferred accounting treatment for vegetation management costs to be inappropriate. He stated that:

Because the utility has full control regarding how it actually operates its vegetative management program, the Staff is correct in suggesting that the implementation of deferred accounting “could easily be manipulated in favor of the Company and its shareholders.” Moreover, as also correctly noted by the Staff, the need for the deferred accounting proposed by I&M is significantly diminished by the utility’s right to file another rate case to recover any excess vegetation management costs that it actually incurs, and that it can do so immediately following the issuance of the Commission’s final order in this case.

Id., p. 18 (citations omitted). The ALJ acknowledged that his recommendation includes regulatory lag, resulting in a slight delay in cost recovery. However, he contended that this may encourage the company to more effectively control vegetation management program spending.

In exceptions, I&M states that “the ALJ and Staff conflated the terms ‘ongoing vegetation management’ and ‘initial vegetation management.’” I&M’s exceptions, p. 16. The company

argues that it is not requesting capitalization of ongoing vegetation management costs, but instead, initial vegetation management costs. I&M explains that, if the clearance zone was cleared and maintained at 15 feet, but is now expanded to 25 feet, the cost of expanding the clearance zone another 10 feet is an initial clearance and should be treated as a capital expense. “From that point forward, the cost of trimming the vegetation within the 25 foot clearance zone would be ongoing maintenance expense.” *Id.*, p. 17. In the company’s opinion, this is consistent with the FERC Plant Account 365. More importantly, I&M asserts, the Staff’s approach significantly increases costs, reduces benefits to customers, and deviates from the company’s historical treatment of these expenses.

I&M also claims that the ALJ recommended retroactive conversion of capitalized costs to O&M costs, which the company argues is inequitable and punitive. I&M asserts that, if vegetation management expenses are retroactively removed from rate base after the expenses have already been capitalized, the company will never be able to recover the costs and will be forced to write them off. Therefore, I&M requests that, in the event the ALJ’s recommendation is adopted, the Commission should apply the decision prospectively.

In replies to exceptions, the Staff argues that I&M’s proposal is markedly similar to DTE Electric’s request to capitalize enhanced vegetation management program costs, which was rejected by the Commission in the December 11 order. The Staff notes that the Commission’s decision was affirmed by the Michigan Court of Appeals in *In re Application of DTE Electric Co to Increase Rates*, unpublished opinion per curiam of the Court of Appeals, issued February 13, 2018 (Docket Nos. 331599, 331868, 332159), p. 5.

The Commission finds that I&M’s proposed vegetation management program is properly treated as an O&M expense. As noted by the Staff, the 2013 FERC audit report for the formula

rates of American Transmission Systems, Inc., states that the capitalizable costs of equipment include the first clearing and grading of land and ROW. This applies only to vegetation management costs incurred for the initial clearing of land during line construction. The company's proposed "clearance zone" is not a first clearing because all these ROWs have been cleared before, possibly multiple times. In addition, the costs incurred to expand the ROW are no longer associated with the first clearing and grading of land during initial line construction. Therefore, going forward, any vegetation management costs the company incurs to maintain or enhance a previously-cleared zone should be treated as an O&M expense with no impact to previously-capitalized vegetation management expenses. For the revenue requirement calculation in the instant case, 2017 and 2018 capitalized vegetation management costs have been removed.

The Commission also adopts the ALJ's recommendation to deny I&M's request to implement deferred accounting, agreeing that the company has not sufficiently demonstrated the benefits to customers. And, because I&M may file another rate case shortly after the Commission's order in this case, the company's need for deferred accounting is substantially reduced.

b. Asset Renewal and Reliability

Concerned with reduced reliability for its customers, I&M proposed the following programs to address aging infrastructure and reduce equipment-related outages: (1) Overhead Rebuild Program; (2) Pole Replacement Program; (3) Underground Residential Distribution Cable and Live-Front Replacement Program; (4) Underground Station Exit Cable Replacement Program; and (5) Distribution Feeder Breaker Replacement Program.

The Staff contended that aging infrastructure does not always require significant spending increases and, therefore, recommended that the jurisdictional costs associated with these programs be reduced. The Staff explained that, beginning with I&M's year-to-date spending for these

expenses, if the costs are doubled, increased for appropriate 2017 and 2018 inflation, and adjusted jurisdictionally, then the company's expenditures should be reduced by \$358,000.

The ALJ found the Staff's position most persuasive. He stated that I&M did not provide:

examples of proof of failed infrastructure--as opposed to high outage rates caused by the failure to adequately attend to vegetation management over the years—[that] would include the number of electric substation failures, as well as the number of cross arm or insulator failures on the system over the last few years (as well as whether the frequency of any of them has been increasing and, if so, to what extent).

PFD, p. 20. Therefore, the ALJ determined that I&M failed to support the proposed increase.

I&M excepts, arguing that the company provided substantial testimony and evidence that aging infrastructure is responsible for system failures and outages. The company claims that it "provided much more probative evidence in the form of the statistical analysis demonstrating increasing failure rates among aging poles and other equipment." I&M's exceptions, p. 23. The company reiterates that its proposed distribution management plan will assist in making substantial improvements to the distribution system and prevent outages.

The Commission adopts the ALJ's findings and recommendation. The Commission finds that I&M did not provide specific and sufficient evidence demonstrating that reduced reliability is due to aging and failed infrastructure. As noted by the ALJ, without detailed examples, the Commission is unable to determine whether or not the company's high outage rates may be attributed to the company's failure to adequately maintain vegetation adjacent to its distribution system. Therefore, the Commission finds that the company's asset renewal and reliability expenditures should be reduced by \$358,000.

c. Major Distribution Project Expenditures, Non-contingency

According to I&M, there are various major distribution projects that are not included in the asset renewal, reliability, or risk mitigation programs, "but are necessary to address contingency

capacity constraints, to improve outage recovery, to replace or upgrade aging or obsolete station equipment, and to perform voltage conversions of select stations and distribution circuits.” I&M’s initial brief, p. 37. The company requested capital expenditures of \$12,424,000 for 2017 and \$13,629,000 for 2018, contending that these projects will improve system reliability, address change in load, and promote safety.

The Staff recommended a test year reduction of \$7,369,000, explaining that there were several discrepancies in I&M’s audit answers. To calculate a more appropriate expense, the Staff started with the company’s current to-date spending, removed 10% for contingency, doubled the result, and applied inflation. According to the Staff, the reduction will still allow I&M to complete the most urgent projects and improve reliability.

Once again, the ALJ agreed with the Staff, finding that I&M failed to explain the customer benefits related to the increased spending and did not include the “failure-rate data” demonstrating that the problems occurring on the company’s system are caused by something other than poor vegetation management. PFD, p. 22, quoting Staff’s reply brief, p. 8. Furthermore, the ALJ found that I&M did not provide a prioritized plan for how the increased funding will be spent. As a result, the ALJ stated that it is impossible to determine whether the proposed spending is reasonable and prudent. The ALJ recommended that the Commission adopt the Staff’s proposed \$7,369,000 reduction to the company’s projected capital expenditures for major distribution projects.

No exceptions were filed and, therefore, the Commission adopts the ALJ’s findings and recommendation.

d. System Modernization

I&M contended that it “plans to implement a series of System Modernization projects that are designed to improve system reliability by increasing visibility into the system as well as deploying distributed automation technologies, which help recover customers automatically during an outage event.” I&M’s initial brief, p. 37. Accordingly, the company forecasted an increase of \$944,000 to deploy supervisory control and data acquisition (SCADA) and distribution outage sensors to improve identification of reliability issues.

The Staff opposed I&M’s increase in system modernization expenses, noting that, to date, the company has not spent any money on this category. And, because I&M claimed that there are urgent reliability concerns and aging infrastructure issues, the Staff asserted that system modernization should not be the company’s top priority.

The ALJ found I&M’s position on this issue persuasive. According to the ALJ, “These programs would appear to do exactly what the Staff would like to see occur, namely improve electric reliability on I&M’s system. The proposed system modernization would also seem to work hand-in-hand with the utility’s proposal to replace ageing infrastructure, both of which should improve the Company’s lagging system reliability.” PFD, p. 24. Thus, the ALJ recommended Commission approval of the company’s proposed \$944,000 increase in system modernization expenditures, including those used in calculating I&M’s rate base.

No exceptions were filed and, therefore, the Commission adopts the ALJ’s findings and recommendation.

e. Cybersecurity and Other Internet Technology Projects

I&M requested increased cybersecurity and internet technology (IT) expenditures for projects that are distributed throughout the company’s capital investments. However, the company

acknowledged that these expenditures are not explicitly separated from the ongoing capital projects set forth in the test year projections. I&M also noted that federal regulations require the company to “provide high assurance that digital computer and communication systems and networks” at its Cook Nuclear Plant are “adequately protected against cyber-attacks.” I&M’s initial brief, pp. 42-43, quoting 10 CFR 73.54.

The Staff agreed with the company that its cybersecurity-related projections “are necessary and prudent at this time,” but recommended a \$3,572,000 disallowance for emergent IT projects. 3 Tr 1192. In addition, the Staff asserted that, due to the type of investment and scale of the cybersecurity costs, the Commission should require I&M to provide assurance that the cybersecurity projects are completed in a timely and efficient manner. Specifically, the Staff recommended that the Commission direct the company to provide a “detailed breakdown of the projected and actual incurred costs for these projects” because it “will provide assurance . . . that the costs being projected in this case are occurring and remaining in budget.” *Id.*, pp. 1192-1193.

I&M opposed the Staff’s recommendation, asserting that technology in the electric utility industry is quickly changing and, therefore, “it is not a best practice to budget specifically to IT capital projects” because other projects may develop that “are of a higher value to our customers.” I&M’s initial brief, p. 43. Additionally, I&M contended that the Staff’s proposed cost review is contrary to ratemaking principles in Michigan: once base rates are set in this case, they should be final and not subject to Commission review. In the company’s opinion, the Staff’s recommendation is akin to unlawful retroactive ratemaking.

The ALJ agreed with the Staff that I&M’s requested expenditures are too vaguely defined, stating that they “have no defined scope and there is [likewise] no certainty that the projects will even occur.” PFD, p. 32, quoting the Staff’s initial brief, p. 27. The ALJ also concurred with the

Staff's conclusion that it would be more appropriate for the company to seek recovery of the expenditures after the costs are known and actually incurred.

I&M excepts, arguing that the Commission often reviews expenses in advance of when the costs are incurred—this is the function of the projected test year allowed under Michigan law. I&M states that “Although the Company plans to expend the costs requested for cyber security, there is no guarantee that the precise requested costs will be incurred or that the Company will spend the exact amount projected. This is because the Company's request for these future costs is based on projected costs and revenues.” I&M's exceptions, p. 24. I&M again contends that the ALJ's suggestion that the company verify expenditures prior to inclusion in rate base amounts to retroactive ratemaking.

In replies to exceptions, the Staff asserts that the ALJ misconstrued its position. The Staff avers that it continues to recommend a \$3,572,000 disallowance for emergent IT projects; however, it supports I&M's cybersecurity costs, confirming that the costs are reasonable and prudent. The Staff reiterates that the company should be required to “provide a detailed breakdown of actual [cybersecurity] costs in future cases” so as to provide the Commission assurance that these projects are proceeding and remaining within budget. Staff's replies to exceptions, p. 4.

The Commission agrees that the ALJ misinterpreted the Staff's position and, therefore, adopts his recommendation in part. The Commission finds that I&M did not provide adequate evidence to support the \$3,572,000 in capital expense associated with the company's emergent IT projects.

As stated by the Staff and noted by the ALJ:

Due to the nature of emergent [IT] projects, it is inappropriate to include them in rates at this time. Pre-approval of spending on projects with no certainty on scope is not an appropriate use of ratepayer money. Furthermore, the likelihood of these

projects is unknown. Given the uncertainty of these projects, Staff does not find them reasonable and prudent at this time.

3 Tr 1192. The Commission agrees and finds that emergent IT project expenses may be approved for recovery in rates only if I&M can prove that the costs were incurred and that they are reasonable and prudent.

However, contrary to the ALJ's recommendation, the Commission finds that I&M's projected cybersecurity expenses are necessary and prudent. In Case No. U-18203, the Commission concluded that cybersecurity threats challenge the reliability, resiliency, and safety of the electric grid and, therefore, "cybersecurity is critical to the operation of a modern electric utility and utilities must continually assess and upgrade their defenses to cyber attacks." November 22, 2016 order in Case No. U-18203, pp. 2-3. Nevertheless, the Commission adopts the ALJ's recommendation that, in future cases, the company provide a detailed analysis of the projected and actual incurred costs for these projects. As stated by the Staff, due to the magnitude of the costs and the gravity of the cybersecurity issue, it is of utmost importance that the company provide the Commission with assurance that the projects are being completed on time and within budget.

f. Recovery of Line Extension Costs

I&M proposed increasing its line extension charges because the company's current charges are based on 2010 costs. The Staff agreed that the rates should be adjusted, but objected to the steep increase. Although I&M attempted to explain that the increase aligns rates with actual costs, the Staff argued that the proposed rates are much higher than the rates other Michigan utilities charge for similar expenses. Therefore, in order to more closely align I&M's line extension rates with those charged by other Michigan utilities, the Staff recommended that the Commission adopt the costs set forth in Staff's Exhibit S-12.1.

The ALJ found the Staff's position persuasive and recommended approval of the Staff's costs in Exhibit S-12.1. The ALJ stated that "The immediate adoption of the Company's proposed line extension cost recovery plan would, it appears, keep many potential customers off the grid." PFD, p. 34. Thus, the ALJ recommended that I&M's proposed line extension rates should be rejected at the present time, and if necessary, phased-in over a number of years.

No exceptions were filed and, therefore, the Commission adopts the ALJ's findings and recommendation on this issue.

g. Recovery of Costs Related to Major Storm Restoration Projects

I&M requested a deferral-based, distribution-related major storm damage restoration project reserve in the amount of \$1,728,000. According to the company, "Although a 'normalized' amount of major storm damage is recognized in the ratemaking process, I&M has and can incur costs that far exceed the normalized level." I&M's initial brief, p. 60. I&M contended that a deferral-related program for the costs will ensure that customers' bills only reflect the true costs of a major storm.

Although the Staff acknowledged that I&M's recommended accounting treatment would reflect actual expenses arising from major storm damage, the Staff believes that the proposed expenses "may not be the best achievable cost. . . . because this type of mechanism can create a disincentive for the Company to properly maintain the system." Staff's reply brief, p. 11. The Staff asserted that I&M may file a rate case to recover major storm damage expenses, if they are, in fact, incurred.

Consistent with his recommendation regarding vegetation management, the ALJ found that I&M's proposed deferred accounting treatment request should be denied; he restated that the company has full control of how it manages major outages. The ALJ also agreed with the Staff

that the company may file a rate case and receive Commission approval to recover major storm damage expenses within a reasonable amount of time. In his opinion, “any regulatory lag . . . would likely serve as an incentive to appropriately manage and maintain its electrical system.” PFD, pp. 36-37.

No exceptions were filed and, therefore, the Commission adopts the ALJ’s findings and recommendation.

h. Distribution Investment and Operations and Maintenance Plan

In light of the discussion above, the Commission finds that I&M is faced with significant investments in the coming years to address aging infrastructure and the need to incorporate advanced technologies into its distribution system. The Commission supports the authorization of necessary investments to ensure the utility’s distribution system is safe, reliable, and resilient. In DTE Electric’s previous electric rate case, the Commission stated that “in order to properly evaluate these investments, and provide a greater level of regulatory certainty, the Commission finds that the rate case process would benefit from the company providing a more comprehensive, forward-looking capital investment and operations plan.” January 31 order, p. 40.

Although I&M provided a distribution management plan, the Commission finds that it could benefit from better organization and prioritization. Thus, the Commission directs I&M to produce and submit a five-year distribution investment and O&M plan that focuses on the priorities described on pages 16-17 of the October 11, 2017 order in Case No. U-17990 *et al.*, including: (1) a detailed description, with supporting data, on distribution system conditions, including age of equipment, useful life, ratings, loadings, and other characteristics; (2) system goals and related reliability metrics; (3) local system load forecasts; (4) maintenance and upgrade plans for projects and project categories including drivers, timing, cost estimates, work scope, prioritization and

sequencing with other upgrades, analysis of alternatives (including advanced metering infrastructure (AMI) and other emerging technologies), and an explanation of how it will address goals and metrics; and (5) benefit/cost analyses considering both capital and O&M costs and benefits. As the Commission explained in the January 31 order, p. 41:

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

The Commission directs I&M to submit a draft plan to the Staff by October 31, 2018, and to meet with the Staff to complete a final five-year distribution investment and maintenance plan to be submitted by May 1, 2019, in Case No. U-20147.

C. Construction Work in Progress and Plant Held for Future Use

The ALJ determined that no party disputed I&M’s proposed \$61,344,000 for CWIP or \$824,000 for plant held for future use and, thus, recommended Commission approval.

No exceptions were filed and, therefore, the Commission adopts the ALJ’s findings and recommendation.

D. Allowance for Funds Used During Construction and Accumulated Provision for Depreciation

The ALJ noted that there were no specific concerns regarding AFUDC and accumulated provision for depreciation. He stated that “I&M’s initial figures should be used in this case, with the caveat . . . that any changes to rate base proposed by the ALJ and adopted by the Commission should be reflected in the level of accumulated depreciation figures used to set the final rates in this case.” PFD, p. 38.

No exceptions were filed and, therefore, the Commission adopts the ALJ's findings and recommendation.

E. Working Capital

I&M stated that it developed its working capital based on the use of the "balance sheet methodology mandated by the Commission in Case No. U-7350." I&M's initial brief, p. 45. Accordingly, the company requested a working capital level of \$49,005,939, which is a slight reduction from the \$49,025,000 that I&M set forth in its application.

The Staff objected to the company's request to recover the incremental expense of \$408,996 related to "the development, filing, and support of this rate case." 3 Tr 1273. In addition, the Staff argued the expense should not be "capitalized and booked to Account 183.3," and "that those expenses be charged to income, (\$136,332 per-year) over a three year period." 3 Tr 1273. The Staff noted that, if I&M's request is approved, the capitalized expenses will accrue interest at the company's authorized ROR. Instead, the Staff proposed that I&M capitalize the rate case expense of \$408,996 without a return on the expense. In the Staff's opinion, the company may recover the full cost of filing this rate case over a three-year period, but the recovery will be limited to actual costs incurred without added interest expenses.

The ALJ agreed with the Staff, stating that "No justification has been provided for allowing the Company to recover anything beyond the actual costs that it expended in filing, presenting, and proceeding with this case." PFD, p. 39. Therefore, the ALJ recommended that the Commission adopt the Staff's proposed working capital of \$48,664,000.

No exceptions were filed and, therefore, the Commission adopts the ALJ's findings and recommendation.

F. Rate Base Summary

Based on the above determinations, the Commission adopts a rate base amount of \$984,631,000 on a jurisdictional basis.

V. CAPITAL STRUCTURE AND COST RATES

A. Capital Structure

The ALJ noted that the specific capital balances and their percentage configuration are set forth in the table on page 33 of the Staff's initial brief. The ALJ stated that none of the parties objected, and therefore, he accepted the proposed capital structure for the purposes of this case.

No exceptions were filed and, therefore, the Commission adopts the ALJ's findings and recommendation.

B. Cost of Equity

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

principles in mind, the Commission turns to the factors that form the basis for determining the ROR for I&M.

I&M used a proxy approach to calculate its proposed ROE, selecting a sample group of 20 companies. To this sample group, the company applied the Capital Asset Pricing Model (CAPM) and Empirical CAPM (ECAPM), the Bond Yield Plus risk premium approach, and the constant growth and multi-stage Discounted Cash Flow (DCF) models. I&M asserted that not all ROE estimating models “adequately reflect changing market dynamics,” and therefore it is “important to give appropriate weight to the methods and their results.” 3 Tr 576. Accordingly, the company stated that the DCF-based results should be carefully considered and that more weight should be provided to the risk premium-based methods. I&M contended that additional factors should be considered regarding their overall effect on the company’s business risk and investor earnings, including: (1) I&M’s generation portfolio and related environmental regulations; (2) the company’s currently-planned capital investment program; (3) customer concentration; (4) I&M’s small size; (5) flotation costs associated with equity issuances; and (6) the company’s cost recovery mechanisms. *Id.*, pp. 504, 541. All things considered, I&M recommended that the ROE in this case be set at 10.60%, but in any event, no lower than the current ROE of 10.20%.

The Staff recommended an ROE of 9.80%, which is the near the high end of its recommended range of 8.00% to 9.90%. Exhibit S-4. The Staff’s recommendation is based on a proxy group of 11-publicly traded utility companies, all of which were included in I&M’s initial proxy group. Although the Staff applied substantially similar DCF, CAPM, and risk premium models to its analyses, the Staff disputed I&M’s application of the multi-stage DCF because “it introduces several additional estimates and forecast sources into the equation to produce its results.” 3 Tr 1227. The Staff also disagreed with the company’s use of a current 30-year Treasury yield in

obtaining the risk premium because a forward-looking 30-year Treasury estimate more closely coincides with the test year.

The Attorney General recommended an ROE of 9.50%. He employed the constant growth and multi-stage DCF models, the CAPM method, and a risk premium approach, and he considered regulatory decisions, current circumstances in the capital markets, and the competitiveness and complexity in the electric utility business. *See*, 3 Tr 862-899; Exhibits AG-5, AG-6, AG-10, AG-11. The Attorney General used the same proxy group that was selected by I&M. Although the average result of the various models was an ROE of 8.23%, the Attorney General adjusted this to a recommended ROE of 9.50% in consideration of small firm size premium.

In his review of ROEs authorized by other utility commissions, the Attorney General noted that the average ROE for 2016 was 9.77%. The Attorney General stated that I&M's proposed ROE of 10.60% is:

unsupported by current economic and capital market conditions. There are many issues and problems associated with [I&M's] assumptions and methodologies used in the process of obtaining such a high cost of equity. These issues include, but are not limited to a single measure of earnings growth rates, an assumption of too-high long-term economic growth rate, using short-term market return to replace the long-term market return, unrealistic market risk premium, incorrect method used in the bond yield plus risk premium approach, and questionable arguments for additional awards for the Company.

3 Tr 849. Accordingly, the Attorney General asserted that I&M's proposed ROE of 10.60% is unreasonable, unsupported, and excessive and should be rejected.

ABATE also applied two constant growth DCF models and a multi-stage DCF analysis, as well as the risk premium and CAPM approaches, to nearly the same proxy group as used by I&M. As a result of these analyses, ABATE determined that an appropriate ROE is 9.30%. ABATE stated that this level of ROE "reflect[s] observable market evidence, the impact of Federal Reserve policies on current and long-term capital market costs, an assessment of the current risk premium

built into current market securities, and a general assessment of the current investment risk characteristics of the electric utility industry and the market's demand for utility securities.” 3 Tr 1069.

ABATE claimed that I&M's constant growth DCF analysis does not support an ROE higher than 8.90% and that the company's multi-stage growth DCF analysis includes “various assumptions” that result in an “inflated” DCF return estimate. *Id.*, p. 1081. ABATE also argued that I&M's CAPM analyses are overstated and the ECAPM analysis double-counts adjustments. Regarding I&M's risk premium method, ABATE stated that the company relied too heavily on forecasted Treasury bond yields, which fails to consider “the highly likely outcome that current observable interest rates” will continue throughout the period in which the approved rates in this case will be in effect. *Id.*, p. 1104.

The ALJ found I&M's requested ROE to be excessive and recommended that the Commission adopt the Staff's proposed ROE of 9.80%. The ALJ agreed with the Staff and ABATE that, currently, public utility ROEs across the country and in the Midwest are steadily decreasing to a level below 10.00% and, therefore, it does not seem reasonable to increase I&M's ROE from 10.20% to 10.60%. According to the ALJ, this decrease is attributable to an improvement in the national and Michigan economies from the low levels of the 2007-2008 period.

In addition, the ALJ concluded that “a few of the model-based analyses performed by I&M's ROE witness appear to be based, at least in part, on questionable assumptions and applications.” PFD, p. 53. Specifically, the ALJ found that the company's two DCF model equations included superfluous estimates and forecast sources. He determined that the inclusion of a current 30-year Treasury yield in the risk premium analysis is inappropriate and that I&M improperly used adjusted betas in the ECAPM methodology. The ALJ also found ABATE's concerns credible that

the company's ROE calculations included "unsustainably high growth rates," an "unrealistic long-term GDP growth estimate," a "manipulated dividend payout adjustment," an "unjustified price-to-earnings . . . ratio assumption," and "inflated market risk premiums." *Id.*, p. 54, quoting 3 Tr 1047. He affirmed ABATE's and the Attorney General's conclusion that flotation costs are not recoverable and should not be used to increase the company's ROE.

The ALJ also stated that I&M's "current credit rating seems to undermine its request to boost its ROE by 40 basis points." *Id.*, p. 55. He contended that the company has a stable credit rating, thus indicating that rating agencies believe I&M and its parent company, American Electric Power (AEP), to be a relatively secure investment and fully able to meet its future payment obligations.

Finally, agreeing with ABATE and the Attorney General, the ALJ asserted that "some of the additional business risk factors that I&M offers to support its requested 10.60% ROE are not specific to I&M, but rather are applicable to most, if not all, companies within the electric utility industry, and – as such – do not justify authorizing a higher ROE than the Company possesses at the current time." *Id.*, p. 56. In the ALJ's opinion, the Staff's recommendation and the testimony offered by ABATE and the Attorney General may support an ROE below 9.80%, and he strongly recommended that the Commission consider reducing the rate in the future. However, in the interest of gradualism, the ALJ concluded that I&M's ROE should be set at 9.80%.

I&M excepts, asserting that the "ALJ's recommendation is more based on arguments against raising I&M's authorized return from 10.2% to 10.6% and not based on a rationale supporting the recommended 9.8% other than adopting the level by default." I&M's exceptions, p. 26. The company argues that the ALJ failed to recommend a return that will most appropriately provide proper compensation for risk, protect the financial security of the utility, and provide a solid ability to attract capital.

Although I&M and the Staff agreed to most cost-of-equity issues, the company asserts that the Staff's analysis contained several flaws. Regarding CAPM, I&M contends that if the Staff relies on historical market return, it should also apply the historical risk-free rate. For ECAPM, the company disputes that it was evaluated "solely using unadjusted 7 Beta coefficients, as [the Staff] asserts." *Id.*, p. 32. Finally, I&M claims that the Staff's calculation of an historical risk premium is not forward-looking and does not take into account the long-standing, widely-recognized inverse relationship between interest rates and equity risk premium.

ABATE objects to the ALJ's use of gradualism, stating that:

Gradualism is a ratemaking concept intended to prevent customer "rate shock." Applying this concept to authorized ROE awards therefore turns it on its head and construes it as a tool to artificially hold ROEs at higher-than-market rates. Doing so unnecessarily hurts ratepaying customers which the policy is intended to protect.

ABATE's exceptions, p. 6. Rather than a gradual decrease of the ROE, ABATE argues that the Commission should reduce the ROE below the ALJ's recommended 9.80%. ABATE contends that there is no guarantee that I&M will file a rate case in the near future and, therefore, customers may have to endure an inappropriately high ROE for many years.

In exceptions, the Attorney General agrees that the ALJ improperly applied the concept of gradualism and reiterates that he provided testimony and evidence supporting an ROE of 9.50%. He states that I&M faces the same risks as similarly-situated utilities and that recent general economic conditions do not require an ROE of 10.60%.

Responding to ABATE and the Attorney General, I&M asserts that, if its ROE is reduced to 9.50% or lower, it "would send the message to investors that Michigan is a volatile regulatory environment in which investors cannot depend upon consistent or fair regulatory treatment." I&M's replies to exceptions, p. 15. I&M disagrees that, over the last five years, the ROEs for most vertically-integrated electric utilities have been trending downward to a level at or below

ABATE's and the Attorney General's recommended ROEs. Instead, by I&M's calculation, the majority of ROEs have been near or above 10%. I&M requests that the Commission reject the ALJ's recommendation and set the ROE no lower than 10.20% in order to appropriately balance the needs of investors with the needs of customers and to give due consideration to economic, financial, and policy considerations.

In replies to exceptions, the Staff states that the ALJ's recommendation of 9.80%:

was actually in excess of the cost-of-equity model results from Staff, the Attorney General, and ABATE. The mid-range of Staff's ROE model results was approximately 9.20%. Accordingly, the 9.80% recommendation did not represent a true cost of equity based on model results, but it represented a gradual trending movement to a more representative ROE.

Staff's replies to exceptions, p. 8. The Staff asserts that the ALJ's recommended ROE is "utility-positive" and a reasonable reduction that corresponds with the national trend. *Id.*

Regarding I&M's reliance on recent ROE awards for other utilities, ABATE asserts that it is not the Commission's practice to give significant weight to an ROE determination from an evidentiary record that is not part of the current proceedings, especially those which are exclusively related to geographically and structurally different utilities.

In reply to I&M's claim that the ALJ's recommendation was not sufficiently supported, the Attorney General states that the ALJ's "choice of 9.8% represented by MPSC Staff's position was a nod to gradualism, not simply a default position" and that the ALJ provided four reasons in support. Attorney General's replies to exceptions, p. 6. Additionally, he contends that I&M's reliance on recently-approved 10.10% ROE awards for other Michigan utilities not only undermines the company's request for an ROE of 10.60% but demonstrates that the request is excessive and that its current ROE of 10.20% is too high. The Attorney General reiterates that current economic conditions do not require the Commission to adopt I&M's proposed ROE, and

he asserts that reducing the company's ROE to 9.80% or lower will not disquiet investors or preclude I&M from maintaining credit.

The Commission notes that the company and ABATE provided extensive discussion regarding the status of the current capital market. The company claimed that the recent volatility and uncertainty in capital markets affect the models used to estimate the cost of equity. I&M explained that, beginning in 2008, the Federal Reserve initiated a policy to lower long-term Treasury yields. Accordingly, the securities held by the Federal Reserve increased from 3.29% of gross domestic product (GDP) in September 2008 to 22.37% of GDP in April 2017. I&M asserted that these Federal Reserve policy actions represented a significant source of liquidity and had a substantial effect on capital markets: not only did market intervention by the Federal Reserve reduce interest rates, it reduced market volatility. *See*, 3 Tr 564-565.

However, in December 2015, the Federal Reserve raised the Federal Funds rate to begin the process of rate normalization. Noting the changing capital market environment, I&M stated:

More recently, interest rates have risen and become increasingly volatile. In the equity markets, sectors that historically have included dividend-paying companies have lost value, as increasing interest rates have provided investors with other sources of current yields.

Id., p. 563. The company asserted that it is particularly important that the Commission keep these market conditions in mind because I&M must compete with other companies, including utilities, for the long-term capital needed to provide utility service.

Although the Commission acknowledges current atypical market conditions, I&M has unique characteristics that offset the some of the risks associated with market volatility. The utility and its parent company, AEP, have historically strong financial credit metrics. I&M also has various rider and tracker mechanisms that are risk mitigating and credit supportive. Additionally, the

revenue decoupling mechanism (RDM) approved in this order further mitigates I&M's risk, ensures more rapid rate recovery, and provides the company a more predictable cash flow.

Therefore, the Commission disagrees that I&M's proposed ROE of 10.60% is appropriate. In setting the ROE at 9.90%, the Commission believes there is an opportunity for the company to earn a fair return during this period of atypical market conditions. This decision also reinforces the Commission's belief that customers do not benefit from a lower ROE if it means the utility has difficulty accessing capital at attractive terms and in a timely manner. The fact that other utilities have been able to access capital despite lower ROEs, as argued by the intervenors, is also a relevant consideration. Additionally, it is important to consider how extreme market reactions to singular events, as have occurred in the recent past, may impact how easily capital will be able to be accessed during the future test period should an unforeseen market shock occur. The Commission will continue to monitor a variety of market factors in future rate cases to gauge whether volatility and uncertainty continue to be prevalent issues that merit more consideration in setting the ROE.

The Commission finds that an ROE of 9.90% will best achieve the goals of providing appropriate compensation for risk, ensuring the financial soundness of the business, and maintaining a strong ability to attract capital. An ROE of 9.90% most appropriately compensates I&M for the regional economic and company-specific aspects of risk, while maintaining its ability to attract capital, and ensuring the continued vitality of the company. It also strikes a balance between the company's interest in investment and the interests of I&M's ratepayers in safe, reliable, and affordable energy. An ROE of 9.90% is at the high end of the Staff's proposed range, and, as several of the parties observed, nationally and in Michigan, ROEs are trending downward. The Commission, in reaching its determination, also takes into consideration the company's

unique circumstances and characteristics, rising interest rates, and the standards set forth in *Bluefield* and *Hope*. The Commission is confident that a 9.90% ROE satisfies the criteria in *Bluefield* and *Hope* in that it is not so high as to place an unnecessary burden on ratepayers, but high enough to ensure investor confidence in the financial soundness of the business. Finally, the Commission is confident that this ROE is appropriate given the company's known capital expenditures.

C. Overall Rate of Return

The Commission adopts a 52.56% to 47.44% debt to equity capital structure, a long-term debt cost rate of 5.15%, an ROE of 9.90%, and an overall weighted cost of capital of 5.76%, as shown on the following table:

Description	Amount (000)	Ratio	Cost Rate	Weighted Cost
Long-Term Debt	\$2,453,538	40.30%	5.15%	2.08%
Common Equity	\$2,214,805	36.38%	9.90%	3.60%
Short-Term Debt	\$ 103,472	1.70%	2.29%	0.04%
Acc. Def. Fed. Inc. Tax	\$1,280,872	21.04%	0.00%	0.00%
JDITC Long-term Debt	\$ 17,925	0.29%	5.15%	0.02%
JDITC Short-term Debt	\$ 756	0.01%	2.29%	0.00%
<u>JDITC Equity</u>	<u>\$ 16,181</u>	<u>0.27%</u>	<u>9.90%</u>	<u>0.03%</u>
Total	\$6,087,548	100.00%		5.76%

VI. ADJUSTED NET OPERATING INCOME

Net operating income (NOI) is calculated by subtracting the company's operating expenses including depreciation, taxes, and AFUDC, from the company's operating revenue. Adjusted NOI includes the ratemaking adjustments to the recorded NOI test year for projections and disallowances. On pages 58-86 of his PFD, the ALJ provided a thorough analysis of the issues and arguments in adjusted NOI, which will not be extensively repeated here.

A. Sales and Revenue Forecast

For the test year, I&M projected that jurisdictional electric sales revenues would increase by approximately \$5,313,363. Although none of the parties objected to I&M's initial sales forecast and its projected overall jurisdictional operating revenue figures, the Staff disputed the company's request to "take a 20% share of its off-system sales margins." Staff's reply brief, p. 14. The Staff stated that no Michigan utilities are permitted to take a share of their off-system sales and I&M failed to explain why it should receive unique treatment.

The Staff noted that when I&M filed its last two rate cases, it belonged to the AEP Power Pool, which allowed the company to make transactions beyond its physical sale of power that could benefit customers. However, the Staff asserted that the AEP Power Pool was terminated in 2014 and I&M no longer has the ability to generate off-system sales margins. Therefore, the Staff contended that 100% of I&M's off-system sales margins should be directly credited to customers. ABATE agreed.

The ALJ recommended adopting the Staff's and ABATE's position on this issue. He agreed with the Staff that, without the AEP Power Pool, "the benefits customers may have received from maximizing a larger pool of AEP generation resources are no longer available." PFD, p. 60, quoting the Staff's reply brief, p. 15. Thus, he determined that all of I&M's projected off-system

sales should be credited back to ratepayers to offset the generation they are paying for in base rates.

I&M excepts, asserting that the ALJ erroneously concluded that customers pay for something other than service. According to I&M, “it is a fundamental cost of service/rate design principle that customers pay for service and not the assets used to provide the service.” I&M’s exceptions, p. 41, citing *Bd of Pub Utility Commr’s v New York Tel Co*, 271 US 23, 32; 46 S Ct 363; 70 L Ed 808 (1926). Rather, I&M opines, it is good regulatory policy to provide a reasonable sharing of off-system sales margins, such as an 80/20 split, between the company and its customers.

In addition, I&M argues that its expertise in the wholesale energy market creates a significant value for the company and its customers. The company states that the 80/20 sharing compensates I&M for successful market competition and risk and provides the company an incentive to participate in the market for the benefit of I&M and its customers. I&M avers that no party presented any evidence to support a departure from the existing regulatory framework established in Case No. U-16801.

Replying to I&M, the Staff reiterates that, as of 2014, the AEP Power Pool no longer exists and, therefore, the 80/20 sharing arrangement is no longer beneficial for customers.

In replies to exceptions, ABATE notes that no other Michigan utilities share revenue from excess power sales and, because the AEP Power Pool was terminated in 2014, I&M’s customers no longer benefit from the optimization of pooled generation resources. Therefore, ABATE requests that the Commission terminate I&M’s 80/20 sharing mechanism. ABATE asserts that “customers must receive the benefit of the generation resources they pay for by being credited 100% of the sales I&M makes outside its system.” ABATE’s replies to exceptions, p. 12.

The Commission agrees with the ALJ, the Staff, and ABATE that I&M's proposed 80/20 sharing of off-system sales margins should be ended. When the 80/20 sharing mechanism was approved in the company's last two rate cases, I&M was a part of the larger AEP Power Pool and the company was able to show that AEP managed and optimized a pool of generation resources for all of its subsidiary companies, including I&M. Because of this arrangement, AEP was able to conduct transactions outside the physical sale of excess power. I&M would not have been able to accomplish the same level of off-system sales margins with its own generation resources only.

The AEP Power Pool was terminated in 2014 and, as a consequence, each AEP subsidiary is now operated as a stand-alone company. Thus, AEP subsidiaries, such as I&M, no longer have the ability to generate off-system sales margins through optimizing the pool of generation resources. The Commission finds that, without the AEP pool, customers will not receive benefits from maximizing a larger pool of AEP generation resources.

As noted by the Staff, I&M's customers are already paying generation costs through base rates. For this reason, and those set forth above, the Commission finds that 100% of I&M's off-system sales margins should be directly credited to customers to offset the costs of generation in base rates.

B. Electric Operating Expense

1. Vegetation Management/Total Distribution Operations and Maintenance Expense

The Staff recommended reducing I&M's annual vegetation management O&M expenses by 100% for 2017 and 50% for 2018. In support of its proposed reduction, the Staff noted that the company's reliability has declined and its five-year spending on this program has been erratic, with a low of \$5,402,000 in 2012, and a high of \$11,758,000 in 2016. The Staff questioned I&M's

forecasted 2017 spending of \$19,569,000 because it “represents the most the Company has ever spent on vegetation management in the last ten years.” 3 Tr 1204.

I&M objected, arguing that the Staff failed to consider the company’s increased spending on vegetation management in 2017, the first year of its four-year transition to a new vegetation management cycle. In addition, I&M contended that its proposed four-year vegetation management program “is a critical component of the Company’s strategy to reduce outages,” as well as to “improve customer experience.” I&M’s reply brief, p. 27. If the Staff’s adjustment is adopted, I&M asserted that the significant investment made to widen clearance zones and improve overall reliability will be at risk.

The ALJ recommended that the Commission adopt the Staff’s proposed disallowance. In the ALJ’s opinion, over the last ten years, I&M’s inconsistent spending demonstrates a lack of commitment to its vegetation management program. The ALJ argued that, had the “utility spent the amounts budgeted for annual vegetation management since its last rate case, . . . I&M’s system would most likely be in better shape at present.” PFD, p. 64. Although the ALJ agreed that I&M could benefit from additional spending on this program, without evidence that the company will actually spend funds on line clearance projects, he found the steep increase in costs for the accelerated four-year program to be unreasonable at this time.

I&M excepts, asserting that it is disingenuous for both the Staff and the ALJ to agree that the company will benefit from additional spending on vegetation management but then recommend that the Commission deny I&M’s request for increased expenses. I&M argues that its proposed cycle-based “program is a proven methodology for reducing vegetation-related outages that the Company anticipates will reduce customer minutes of interruption by 68%.” I&M’s exceptions, p. 20.

The company also objects to the ALJ's determination that it has not spent budgeted vegetation management expenses. I&M argues that, since its last rate case, the company has increased spending and has begun the first year of its four-year transition consistent with the plan presented in this case. Additionally, the company states that its proposed deferral mechanism provides assurance that, if I&M fails to spend the forecasted O&M expenses on vegetation management, customers will receive a refund.

Finally, I&M disputes the ALJ's claim that the company's use of deferred accounting "could easily be manipulated in favor of the Company and its shareholders." *Id.*, quoting PFD, p. 18. The company contends there is no factual basis for this conclusion and, therefore, "such a statement is inaccurate and offensive." *Id.* Instead, I&M argues, the company's proposed accounting method is more beneficial to customers because deferral accounting may provide an exact reconciliation of incurred costs to related revenue.

The Commission finds persuasive the ALJ's findings and recommendation. As noted by the Staff and the ALJ, over the last five years, the company has never spent more than \$11 million annually on line clearing and, accordingly, is unlikely to spend the requested \$19 million. And, as pointed out by the Staff, the Commission has never approved a four-year vegetation management cycle for any other Michigan utility given the growing patterns of trees in this part of the country. Therefore, until I&M shows that it consistently spends budgeted amounts for line clearing, the Commission finds that the Staff's proposed amount of \$9,192,679 for 2018 is sufficient to allow the company to continue its current trim cycle and to improve customer reliability. As the Commission discussed above, I&M is expected to incorporate O&M expense, along with capital expense, for vegetation management in its five-year distribution plan.

2. Depreciation and Amortization Expense

I&M projected a jurisdictional depreciation and amortization expense of \$55,838,000 for the test year. The Staff proposed a \$3,295,000 disallowance related to the depreciation rate for Rockport Unit 2, the depreciation period for the company's AMR meters, and the impact of the Staff's capital expenditure adjustments on depreciation expense. The Staff stated that because it accepted I&M's proposal to adjust the retirement date for Rockport Unit 1 from 2044 to 2028, for the purpose of setting depreciation rates, the retirement date of Rockport Unit 2 should be changed from 2022 to 2028. The Staff explained that the proposed adjustment will correspond with "what was previously done for the [company's] Tanners Creek plant when it retired. . . . [and] it is consistent with I&M's assumption within the demolition study that Rockport Unit 2 will be demolished at the same time as Rockport Unit 1." 3 Tr 1176.

The Staff also objected to the company's accelerated depreciation period for its AMR meters for the purpose of installing AMI. The Staff argued that it is unreasonable to artificially shorten the remaining life of the company's AMR meters in order to substitute one automated technology for another. Although I&M claimed that AMI was "new and under development" when it decided to install AMR meters, the Staff noted that, at the time I&M made this decision in 2007-2011, other Michigan utilities, such as Consumers Energy Company (Consumers) and DTE Electric, were installing AMI meters. Staff's initial brief, p. 57, quoting 3 Tr 95. In the Staff's opinion, "The expense for the Company's indecisiveness in metering technology is not a burden that the ratepayer should be forced to bear." *Id.*

ABATE disputed the company's depreciation proposal for the Rockport Plant, stating that "I&M does not have any firm plans to retire Rockport Unit 1 in 2028 rather than 2044." 3 Tr 913.

If I&M retires any Rockport units in 2022, as proposed by the company, ABATE argued that it would leave I&M with far too little capacity to serve its customers.

I&M responded to the Staff, noting that the Rockport Unit 2 lease expires on December 7, 2022, and the company must “determine whether to renew the lease or return Unit 2 to the lessors.” I&M’s reply brief, p. 36. Therefore, the company argued that it is reasonable and prudent to depreciate Rockport Unit 2 plant-in-service through 2022, which reflects the end-of-lease date and the anticipated end-of-useful life.

Regarding the Staff’s objection to the accelerated depreciation period for its AMR meters, I&M stated that it is merely seeking to coordinate the depreciation life with the present and expected performance of the AMR meters. Accordingly, I&M claimed, there is a need for the company to present a future business case for removing AMR meters and replacing them with AMI meters. The company requested that the Commission approve depreciation rates for its AMR meters that “reflect the shorter life over the next 5 years,” or, at a minimum, “use a weighted average of the remaining life of I&M’s metering infrastructure” when setting rates. I&M’s reply brief, p. 38.

I&M argued that ABATE’s proposal to extend the retirement date of Rockport Unit 1 to 2044 is based on an unreasonable estimate and an outdated integrated resource plan (IRP). The company asserted that, in order to operate Rockport Unit 1 after 2028, it would require an investment of \$1 billion or more, which is not a reasonable or prudent investment for customers.

The ALJ found that the Staff’s proposal to set the decommissioning date for both Rockport units at 2028 is the most reasonable and “consistent with the financial treatment surrounding the utility’s retirement of its Tanners Creek plant.” PFD, p. 67. In addition, the ALJ noted that this treatment is consistent with I&M’s demolition study, which stated that Rockport Unit 2 will be

demolished at the same time as Rockport Unit 1. The ALJ asserted that ABATE's proposal to push back the operational life for Rockport Unit 1 to 2044 "would have the dual problem of making ratepayers pay a huge cost of making it a cleaner coal-burning plant, while concurrently shifting any unrecovered costs related to its current plant depreciation to future customers." *Id.*

Regarding I&M's request to reduce the depreciation period for its AMR meters, the ALJ determined that the company's proposal would be unjustly burdensome to ratepayers. Citing the Staff's testimony on this issue, the ALJ agreed that "the incremental benefits of moving from AMR to AMI are negligible compared to the costs of implementing AMI." *Id.*, p. 68, quoting 3 Tr 1193. He also recommended that the Commission reject I&M's request to use a weighted average. The ALJ explained that, pursuant to I&M's proposal, AMR meters would be removed from service based on an average life, which results in the replacement of meters before the end of their useful life. He stated that it is "inappropriate to shorten the life of a fully functioning asset for marginally improved operational benefits." PFD, p. 69, quoting Staff's initial brief, p. 58.

In exceptions, I&M asserts that the ALJ incorrectly determined that the depreciation rate for the Rockport units should coordinate with the demolition date. The company argues that the depreciation rate should be set based on the expected remaining useful life of the asset and not the date on which the asset will be dismantled. Therefore, I&M states that the record evidence in this case shows that the expected remaining useful life of Rockport Unit 2 is 2022 when the company's lease expires.

In addition, I&M claims that setting the retirement date for Rockport Unit 2 to 2028 causes an accounting issue. According to Generally Accepted Accounting Principles (GAAP), I&M states that it "will be required to depreciate the leasehold improvements at Rockport Unit 2 over their current lease expiration date ending in 2022. . . . [This] would force I&M to realize a net operating

loss specific to this issue as a result of base rate revenues being significantly less than ongoing depreciation expense.” I&M’s exceptions, pp. 34-35. Therefore, if the Commission finds that depreciation rate for Rockport Unit 2 should be set using 2028 as the retirement date, the company requests that the Commission include specific language in the final order approving the establishment of a regulatory asset for the shortfall in depreciation expense. *Id.*, p. 35.

ABATE excepts, asserting that the ALJ misunderstood its position regarding the retirement date for Rockport Unit 1. “To clarify, ABATE did not suggest changing the depreciation date for Rockport Unit 1 to 2044, but proposed continuing the use of that date. As ABATE noted in this proceeding, I&M’s current operative IRP, completed in 2015, clearly shows Rockport Unit 1 operating until 2044.” ABATE’s exceptions, p. 1. ABATE reiterates that I&M failed to provide any evidence that Rockport Unit 1 will be retired in 2028 and it is unreasonable for the company to claim that its current IRP is out-of-date and not applicable to the useful life of Unit 1.

In replies to exceptions, I&M disputes that the 2044 retirement date for Rockport Unit 1 should be maintained just because that date is used in the company’s most recent IRP. Instead, I&M claims, “there is no better time to set depreciation rates based on the most current information than in a general rate case because rates can be based on all cost aspects including depreciation expense.” I&M’s replies to exceptions, p. 17. In addition, I&M argues that ABATE’s reliance on the company’s 2015 IRP is misguided because, based on more recent evidence on the record, it would be unreasonably expensive to operate Rockport Unit 1 after 2028.

The Staff replies that, in exceptions, I&M merely rehashes its rebuttal arguments that were rejected by the ALJ. The Staff continues to advocate for a 2028 retirement year for Rockport Unit 2 and reiterates that this recommendation is consistent with I&M’s demolition study and the treatment applied to the company’s Tanners Creek plant retirement.

In replies to exceptions, ABATE reiterates that it would be inappropriate for the Commission to alter the service life set forth in the company's current IRP because I&M has not provided any documentary evidence that Rockport Unit 2 will be retired prior to 2044. According to ABATE, "Until there is a replacement plan provided for early retirement of the Rockport Generating Station, the existing retirement date developed through the IRP process should be maintained." ABATE's replies to exceptions, p. 12.

The Commission adopts the ALJ's findings and recommendation. The Commission finds that a 2028 retirement date for Rockport Units 1 and 2 is consistent with the financial treatment provided to I&M's retirement of its Tanners Creek plant. In the September 26, 2014 order in Case No. U-17524, the Commission approved current depreciation rates for Rockport Unit 1, which were adjusted after the June 1, 2015 retirement of the Tanners Creek plant. As a result, I&M combined the utility plant in service and depreciation reserve balances for the Tanners Creek plant with Rockport Unit 1 so that it could recover the remaining net book value of both plants over the remaining life of Rockport Unit 1. The Commission finds that it is reasonable and prudent to apply this same treatment to Rockport Units 1 and 2, thus adjusting the retirement date for Rockport Unit 2 from 2022 to 2028.

In response to ABATE's concerns, the Commission agrees with the ALJ that, if the Rockport Unit 1 plant-in-service is depreciated through 2044, ratepayers will be responsible for an unreasonably large investment to make the unit a cleaner coal-burning plant, and any unrecovered costs related to its current plant depreciation will be shifted to future customers.

As discussed above, the Commission approves recovery of Rockport Unit 2 costs through 2028 for setting base rates in this case. However, for accounting purposes, the Commission notes that the Rockport Unit 2 costs will be depreciated through 2022 on I&M's books consistent with

GAAP. Therefore, the Commission approves the establishment of a regulatory asset for the difference between the Rockport Unit 2 depreciation expense recorded on I&M's books using a 2022 retirement date and depreciation expense used for ratemaking based on a 2028 retirement date. Upon termination of the lease, currently expected in 2022, I&M shall begin amortizing the regulatory asset through the 2028 retirement date used for setting Rockport Unit 2 depreciation expense for base rates in this case. This regulatory accounting treatment allows I&M to match Rockport Unit 2 total depreciation expense included in base rates in the instant case with the expense included in the GAAP financial statements for Rockport Unit 2.

The company claims that "using a five year remaining life for the AMR meters serving I&M's customers will better match the expected useful life of the assets and better position I&M to economically provide customers access to AMI meters in a reasonable timeframe." I&M's reply brief, pp. 37-38. In response, the Staff noted that I&M received Commission approval in Case No. U-16801 to begin deploying AMR meters in 2011, the purpose of which was to reduce the costs of manual meter reading. I&M's AMR meters will not fully depreciate until 2026.

The Commission agrees with the ALJ that I&M's proposal to accelerate the depreciation period of its AMR meters should be rejected. The company's proposal results in the replacement of fully-functioning meters before the end of their useful life, which is not prudent or beneficial to ratepayers. I&M will incur substantial expense to replace AMR with AMI, providing only incremental benefits to the company and its ratepayers. Therefore, the Commission denies I&M's request to accelerate the depreciation period or, in the alternative, use a weighted average of the remaining life of its AMR meters.

3. Injuries and Damages Expense

The Staff recommended reducing I&M's injuries and damages expense by \$274,000. I&M objected, asserting that the Staff's proposed disallowance "does not accurately reflect the Company's projected . . . expenses" for the test year. I&M's reply brief, p. 44.

The ALJ adopted the Staff's injuries and damages calculation as set forth in Exhibit S-3, Schedule C5.1. According to the ALJ, using the Staff's "five-year historical average 'smooths the effect of [these] volatile and difficult to control expenses,' which would likely 'reduce the impact of rate shock' on I&M's customers." PFD, p. 70, quoting 3 Tr 1268. In addition, he noted that the same methodology has been adopted by the Commission in several recent rate cases.

No exceptions were filed and, therefore, the Commission adopts the ALJ's findings and recommendation.

4. Government Relations Expense

I&M projected a \$617,938 government relations expense for the test year. In the Staff's opinion, \$334,379 relates exclusively to government relations that are specific to Indiana and, therefore, the Michigan jurisdictional portion of the expense should be reduced by \$52,000.

I&M responded that the company's COSS allocated the total company balance from the related accounts "to the Michigan jurisdiction using a payroll allocator, resulting in a total Michigan retail expense of \$95,510. It is inappropriate to both direct assign and then further allocate an expense." 3 Tr 744. The company argued that, if the Commission adopts the Staff's proposed disallowance, the remaining balance should be assigned directly to I&M's Michigan-based ratepayers, which would increase the Michigan jurisdiction cost of service by \$188,049.

The ALJ agreed with the company, finding that the "payroll allocator methodology used by I&M appears to be the most appropriate means of allocating overall governmental relations

expenses between Indiana and Michigan.” PFD, p. 71. He recommended that the Commission reject the Staff’s proposed disallowance.

No exceptions were filed and, therefore, the Commission adopts the ALJ’s findings and recommendation.

5. Fossil Fuel Generation and Operations and Maintenance Expense

a. Expense Related to Planned Outages

The Attorney General claimed that I&M’s planned outage portion of the fossil generation O&M expense is excessive compared to the record. According to the Attorney General, the company projected \$4,724,000 for planned outages for the test year, however I&M only incurred \$797,000 for planned outages in 2016. He acknowledged that the company’s planned outage expense is cyclical, but that I&M’s six-fold increase between the historical test year and the projected test year is unsupported and unreasonable.

I&M disagreed, asserting that the \$797,000 expense for 2016 was “extraordinarily low” due to planned outages in 2014 and 2015 to comply with environmental requirements. 3 Tr 248. According to I&M, other maintenance outage work was performed during these outages that would have likely been planned for 2016. The company contended that this maintenance work significantly reduced the planned outage expense for 2016 and, therefore, it is not representative of typical planned outage expenses. I&M averred that the \$4,700,000 estimate for the 2018 test year is reasonable and prudent because it falls below the 2012-2016 average.

The ALJ found I&M’s explanation persuasive and recommended adoption of the company’s projected 2018 planned outage expense of \$4,700,000. Citing I&M’s testimony, he noted that the company’s annual outage expenses were approximately \$2,000,000 for 2012, \$7,600,000 for 2013, \$11,300,000 in 2014, and \$103,000,000 in 2015. The ALJ stated that the \$797,000 expense for

2016 “is clearly an anomaly and should not be used (as the Attorney General has proposed) to help estimate such expenses for the 2018 test year.” PFD, p. 73.

No exceptions were filed and, therefore, the Commission adopts the ALJ’s findings and recommendation.

b. Consumables Expense

The Attorney General also recommended a \$26,200,000 disallowance for chemicals used in the operation of the DSI systems at Rockport Units 1 and 2 and the expenses associated with the SCR system at Rockport Unit 1, asserting that I&M failed to adequately support the cost. In response, the company stated that it provided sufficient evidence to show that the DSI and SCR systems are reasonable and prudent investments necessary to “continue to operate the Rockport Plant in compliance with environmental requirements.” I&M’s reply brief, p. 31.

Citing his rate base recommendation above, the ALJ noted that the DSI systems for Rockport Units 1 and 2 and the SCR system for Rockport Unit 1 were properly included in rate base. Thus, he determined that the cost “of the consumables needed to operate those systems should . . . be included as part of I&M’s total test year O&M expenses.” PFD, p. 74.

In exceptions, the Attorney General reiterates that, in light of I&M’s request to modify the consent decree governing the installation of air pollution control systems at the Rockport units and the proposed revised retirement date for Rockport Unit 1, the company failed to adequately demonstrate that the DSI and SCR systems, and related consumables, are necessary.

On page 29 of its replies to exceptions, I&M states that its “forecasted consumables expenses are reasonable and necessary expenses that must be incurred to operate the Rockport plant. Furthermore, these consumables costs have been found reasonable and necessary and approved for

recovery in each of I&M's PSCR filings since this equipment began operation." For these reasons, the company states that the Attorney General's proposed disallowance should be rejected.

As set forth in the rate base section above, with the exception of the SCR costs associated with Major Project 7, the Commission determined that I&M's proposed fossil, hydro, and related environmental capital expenditures are necessary to improve safety, efficiency, and reliability, to reduce outages, and, for some projects, to comply with federal mandates. Likewise, the Commission finds that I&M's projected costs for the consumables needed to operate the DSI and SCR systems are reasonable and prudent. In other general rate cases, the Commission has approved consumables as a recoverable PSCR expense, which is a fuel-related O&M expense included in base rates as part of the PSCR base. The PSCR base is an estimated amount of fuel and purchased-power expense. If the estimate for the coming year is more than the expense collected through base rates, the residual amount is collected through the PSCR factor. Although it is a single recovery of the total expense, two sources collect the total: the PSCR base in base rates and the PSCR factor in cases involving Public Act 304 of 1982. Therefore, the Commission notes that, in this case, the consumables expense approved for PSCR treatment will be trued-up in the company's next PSCR reconciliation as is done for all utilities in Michigan.

6. Solar Operations and Maintenance Expenses

I&M included solar expenses for its generating facility and the associated property tax in its O&M expenses. These expenses are properly included in the company's renewable energy plan case. Therefore, the Commission finds that, for the Michigan jurisdiction, I&M's O&M expenses should be reduced by \$63,958 for solar expenses and \$17,256 for solar other tax.

7. Employee Incentive Compensation and Executive Retirement Expense

a. All-Staff Incentive Compensation Plan Expense

I&M projected a total expense of \$21,300,000 for its employee incentive compensation plan (EICP), which includes \$17,500,000 for its short-term EICP and \$3,800,000 for its long-term EICP. The company stated that its:

compensation and benefit programs are designed to support customers' need for safe and reliable electric service. The [company accomplishes] this by focusing performance measures on objectives that ensure customer value. [I&M takes] a holistic approach to designing its compensation and benefit programs as a reasonable and market competitive total employee rewards package.

I&M's initial brief, p. 63. Although the Commission recently disallowed a portion of EICP expenses in Consumers' and DTE Electric's rate cases, I&M argued that, compared to those cases, the company demonstrated that all its EICP benefits customers. I&M explained that its EICP "enable[s] the attraction, retention, motivation and engagement of employees with the skills and experience needed to efficiently provide service to customers." *Id.*, p. 64. In addition, the company contended that the performance measures included in the programs encourage improvement in operations and safety and help foster cost-conscious values and high performance among employees.

While the Staff acknowledged that the company's short-term EICP "provides annual incentive compensation to motivate and reward employees, and is based on achievement of financial, safety and strategic initiatives," part of the criteria by which employees are measured is inappropriately linked to financial performance measures that largely benefit shareholders. 3 Tr 1269. As a result, the Staff recommended reducing I&M's proposed EICP expense by \$4,258,200 to exclude expenses associated with the achievement of financial performance measures. The Staff cited a multitude of past Commission cases in support of its proposed disallowance.

The Attorney General argued that, “because of the way it is funded,” I&M’s short-term EICP “only provides significant payments to employees when the AEP EPS [earnings per share] meets required levels.” 3 Tr 841. Additionally, pursuant to the long-term EICP, he asserted that company employees are rewarded “strictly on shareholder returns and EPS.” *Id.* In the Attorney General’s opinion, I&M failed to adequately quantify benefits to ratepayers and, therefore, the total cost for the short-term and long-term EICPs should be rejected.

The ALJ found the Staff’s position to be the most reasonable. He determined that I&M structured its basic EICP so that it “does not lean too far in the direction of rewarding its shareholders as opposed to its ratepayers.” PFD, p. 77. However, the ALJ stated that:

Despite claims by the Company to the effect that it demonstrated that its incentive compensation programs benefit customers in this case, testimony offered by the Attorney General’s witness tends to indicate that possibly as little as 25% of the benchmarks used to set an employee’s bonus compensation are actually tied to activities that help ratepayers.

Id. Therefore, he found that the Staff’s proposed disallowance equitably removes EICP expenses strictly tied to financial performance measures that provide no appreciable benefits to ratepayers.

The Attorney General excepts, restating that all costs associated with the short-term and long-term EICPs should be excluded. He argues that, pursuant to the standard set forth in the December 22, 2005 order in Case No. U-14347 (December 22 order), I&M did not provide sufficient evidence demonstrating that the benefits to ratepayers from the EICPs is commensurate with the costs of the programs. The Attorney General reiterates that the short-term EICP is primarily dependent on the achievement of financial goals, benefitting shareholders and not ratepayers.

In reply, I&M states that a primary component of the short-term EICP is operational goals, which largely benefit customers. The company asserts that “The AG’s argument that the incentive

compensation program is flawed because it is funded only when earnings per share meets targeted levels ignores the fact that this level has almost always be [sic] achieved. Accordingly, the operating measures drive the Company's annual incentive program." I&M's replies to exceptions, p. 26.

The Commission finds persuasive the ALJ's findings and recommendation. Only the short-term EICP expense, which is strictly tied to operational measures, should be approved because it provides appreciable benefits to ratepayers. Financial measures, however, predominantly benefit shareholders. Therefore, the Commission finds that all of the expenses associated with I&M's long-term EICP are inextricably connected to financial measures and should be disallowed. For the same reason, the Commission finds that the \$4,258,200 linked to financial measures in I&M's short-term EICP should also be disallowed.

b. Supplemental Executive Retirement Plan Costs

The Staff and the Attorney General recommended a disallowance of all costs associated with I&M's non-qualified post-retirement benefit plans, generally referred to as supplemental employee retirement plans (SERP), for upper-level managers and executives that exceed Internal Revenue Service (IRS) limits. They contended that these programs provide almost no benefit to ratepayers.

I&M disagreed, asserting that its SERP uses the same benefit formulas that are used in the qualified retirement plan and, thus, is not subject to the IRS benefit limitations. In addition, the company argued that the SERP is "an integral component of a reasonable and market competitive total compensation package" that is necessary for "maintain[ing] highly qualified employees with skill sets needed to benefit customers." I&M's reply brief, p. 33.

The ALJ found that, in the last seven rate cases, the Commission has consistently excluded SERP from the revenue requirement because the benefits to ratepayers are not commensurate with

the costs. *See*, December 22 order, p. 34; December 23, 2008 order in Case No. U-15244, pp. 34, 37-38; January 11, 2010 order in Case No. U-15768, p. 49; October 20, 2011 order in Case No. U-16472, p. 68; November 19, 2015 order in Case No. U-17735, p. 72; January 31 order, p. 85; and February 28 order, p. 106. And, he found that “the Attorney General accurately contends that the Company has simply ‘not justified the cost in this case.’” PFD, p. 79, quoting the Attorney General’s initial brief, p. 17.

No exceptions were filed and, therefore, the Commission adopts the ALJ’s findings and recommendation.

8. Projected Test Year Tax and Allowance for Funds Used During Construction

a. Income Taxes

I&M projected federal income tax of \$78,000,000 for the test year, \$5,390,000 of which is attributable to the Michigan jurisdiction. The Staff recommended increasing the company’s jurisdictional federal income tax expense by \$2,230,000.

However, effective January 1, 2018, the base federal corporate income tax rate was reduced from 35% to 21% with the enactment of the TCJA. The ALJ noted that, on page 2 of the December 27 order, the Commission required all Michigan utilities to file information detailing the calculation of the change in revenue requirements with and without the TCJA and the best way “any resulting benefit should flow back to ratepayers.” Because the change in the base corporate federal income tax rate was not effective until long after the record closed in this case and after the parties had filed their initial briefs, the ALJ found that “there is absolutely nothing in the docket that can be used to determine the specific effect of the recently-enacted federal tax rate reduction.” PFD, p. 81. Therefore, acknowledging that the rates will likely need to be adjusted after the

directives of the December 27 order are completed, for purposes of this case, he recommended that the test year jurisdictional federal income tax amount of \$4,017,000 should be adopted.

ABATE excepts, arguing that the TCJA has a significant effect on several issues, such as current tax expense and net cost of new entry (CONE), in this proceeding. ABATE asserts that the Commission should account for these changes and reduce the revenue requirements accordingly.

On page 31 of its replies to exceptions, I&M states that “There is no basis for ABATE’s exception. The Commission has already provided for an orderly process to address the issues.”

The Staff replies that, in the February 22, 2018 order in Case No. U-18494 (February 22 order), the Commission did not state that the TCJA must be addressed in this case. “In fact, the Commission explained that if the TCJA is not addressed in this case that I&M should file an application within 30 days after the issuance of the final order. Therefore, it is not pressing to address the TCJA in this case.” Staff’s replies to exceptions, p. 15. The Staff states that there is no record evidence for the parties to address regarding the TCJA and, thus, it would be unreasonable for the parties to evaluate the impacts in this case.

In response to ABATE’s claim that net CONE may be affected by the TCJA, the Staff notes that net CONE has not yet been adjusted by the regional transmission organization, PJM Interconnection, L.L.C. (PJM). In the Staff’s opinion, the Commission should defer a recalculation of net CONE until after it has been modified by PJM, otherwise “it would dilute the benefit of relying on Net CONE as calculated by PJM.” *Id.*, p. 16.

As noted by the Staff and the ALJ, the change in the base corporate federal income tax rate went into effect after the close of the record and after the parties filed their initial briefs in this case. Consequently, there is no record evidence by which the parties or the Commission can properly and adequately evaluate the impact of the TCJA on I&M’s revenue requirements. The

February 22 order states that if the final order in the applicable pending rate case does not address the current tax impact, then I&M must file a Credit A application. Therefore, the Commission finds that I&M shall file a Credit A application in Case No. U-20107 by May 14, 2018.

b. Taxes Other Than Income and Allowance For Funds Used During Construction Costs

The ALJ found that there was no dispute regarding I&M's proposal to recover jurisdictional amounts of approximately \$13,000,000 in taxes other than its federal income tax, as well as \$3,100,000 for AFUDC. He recommended that the Commission adopt these costs.

No exceptions were filed and, therefore, the Commission adopts the ALJ's findings and recommendation.

C. Adjusted Net Operating Income Summary

In summary, the Commission finds that I&M's jurisdictional projected NOI for the calendar year 2018 test year is \$29,421,000.

VII. OTHER REVENUE AND ACCOUNTING ISSUES

I&M and the parties stipulated that the \$51,700,000 rate increase initially proposed in its application should be set as the limit for the company's revenue deficiency. According to I&M, the \$51,700,000 limit included the correction of an error regarding the amount of present revenues the company was forecasted to receive from its PSCR component in the test year. I&M claimed that the error, and its correction, did not change the company's case, specifically with regards to the revenue requirement and rate design.

The Staff argued that the error caused a nearly \$10 million difference in potential rate relief and represented a significant amendment to I&M's application. In the Staff's opinion, maintaining the requested \$51,700,000 revenue requirement would require different calculations and resulting

rates, which the company did not file. The Staff stated that, “although the Company’s decision to limit its requested rate relief” after it discovered the error “resolves many of the resulting problems, it does not diminish the magnitude of the mistake.” Staff’s reply brief, p. 17.

The ALJ found that none of the parties provided fully-updated figures addressing I&M’s mistake. Recognizing that the parties may wish to address this matter in exceptions and replies, he asserted that “the record is devoid of testimony regarding both the total effect of this error and the results arising from I&M’s decision to simply limit its request for rate relief to the \$51,700,000 sought in its application.” PFD, p. 85. Therefore, the ALJ found that the numbers provided by the witnesses and used by the parties in initial and reply briefs should be adopted for purposes of the PFD.

The Staff excepts, asserting that the ALJ incorrectly found that the parties did not file updated testimony or figures correcting the company’s present revenue error. The Staff avers that it addressed the error on pages 1280-1281 of volume 4 of the transcript and in Exhibit S-1. I&M agrees.

On page 27 of his exceptions, the Attorney General also responded to the ALJ’s claim stating that “the Company is the party best able to provide such figures but failed to do so.” Therefore, he argued that I&M should not receive the benefit of the doubt regarding the significance or impact of the adjustments.

The Commission finds that, as set forth in testimony and exhibits, the Staff provided a correction to the company’s PSCR revenue. *See*, 4 Tr 1280-1281; Exhibits S-1 and S-20. Therefore, the Commission adopts the Staff’s updated present revenue calculation.

VIII. REVENUE DEFICIENCY SUMMARY

In accordance with the foregoing findings, I&M's jurisdictional revenue deficiency for the test year is computed as follows:

Rate Base	\$984,631,000
Required Rate of Return	5.76%
Income Required	\$56,697,000
Adjusted Net Operating Income	\$29,421,000
Income Deficiency (Sufficiency)	\$27,276,000
Revenue Multiplier	1.6315
Subtotal	\$44,502,000
Open Access Transmission Tariff Costs	\$4,616,000
Total Revenue Deficiency	\$49,118,000

IX. COST OF SERVICE

A. Allocation of Distribution Expense

To allocate the company's generation production expense, I&M used the 4 coincident peak (CP) 75-0-25 method, applying a 75% cost factor to peak demand and 25% to total energy use.

The Staff supported the company's allocation method.

ABATE recommended that the Commission require I&M to use 4CP 100-0-0, which assigns 100% of the company's production costs on the basis of demand. ABATE argued that 4CP 100 is the most representative of cost causation because the company's "production capacity obligation and investment is driven by its summer peak demand." 3 Tr 100.

The ALJ noted that the Commission recently rejected the 4CP 100 allocation method for determining class revenue responsibility for I&M's customers in Case No. U-17698. In addition, he stated that the Commission has rejected the 4CP 100 allocation method in numerous cases, finding that "year-round energy usage (and not just summer peak use) is an appropriate consideration when determining the proper allocation of a utility's production costs." PFD, p. 89. He determined that the "logic underlying the Commission's previous decisions still holds." *Id.* Therefore, because ABATE presented no new evidence justifying reconsideration of the production cost allocation method, the ALJ recommended that the Commission should adopt I&M's proposed 4CP 75-0-25 allocation method in this case.

On page 13 of its exceptions, ABATE reiterates that the 4CP 100 allocation method "is the most cost reflective method for I&M's electric system" because it allocates costs according to demand, the source of which is summer peak use.

In reply, I&M states that the Commission has clearly and consistently determined that 4CP 75-0-25 is the most appropriate production cost allocation method for the company and ABATE has provided no new evidence justifying a change. The Staff and the Attorney General agree.

The Commission agrees with the ALJ that the rationale on page 100 of the January 31 order applies in this case. I&M's production system was not designed and built exclusively to meet demand. Rather, the company's production plant was developed to both provide capacity *and* deliver energy at the lowest overall cost to all customers who use the system. Because AEP's, and thereby I&M's, generating system includes a mix of base load, intermediate, and peaking plants, the 4CP 75-0-25 allocation method better recognizes the value of capacity in the company's system. And, year-round energy usage, and not just summer peak use, is an appropriate

consideration when determining the proper allocation of I&M's production costs. The Commission therefore finds that I&M's 4CP 75-0-25 allocation method should be approved.

B. Cost-of-Service-Based Capacity Pricing Calculation for All Classes

The parties presented various methods for calculating capacity costs and the capacity rate that should be used by I&M on a going-forward basis and applied to all customer classes.

The Staff contended that I&M should be permitted to recover only the costs that are directly related to capacity service. Therefore, the Staff recommended exclusion of some production-demand classified costs because they are not capacity-related.

Next, the Staff argued that "the proper cost of capacity is the Cost of New Entry (CONE), or the cost to build a combustion turbine (CT)." 3 Tr 1247. According to the Staff:

The characteristics of a CT are such that it effectively supplies only capacity. A CT is relatively expensive to run to produce energy, but relatively inexpensive to build. Therefore, it is only economically utilized to supply energy in those hours when load is at its highest. These hours are also those which are considered to set the capacity need of the utility to serve its customers. Plants other than CTs are more expensive to build and less expensive to run, making them the most cost-effective choice only if they run enough hours a year so that the total cost is lower. Therefore, the difference between the cost to build a CT and any other type of plant is the capital cost expended to produce lower energy costs. In Staff's opinion, this cost should properly be considered an energy cost. However, the net sales to the market should be applied as an offset to the capacity-related costs. As all energy is bid into the market at the cost to run a plant, but plants are paid if dispatched at the highest bid called in the supply stack, these net-energy market sales (imperfectly) capture what Staff would consider to be the energy related portion of capacity costs. Therefore, to remove all costs above a CT and then apply an offset which effectively, if imperfectly, does the same, would be double counting the offset.

Id., pp. 1247-1248.

ABATE provided several suggestions: (1) I&M's retail capacity rate should be based on an average of the PJM Reliability Pricing Model (RPM) capacity rate applicable to load outside the company's service territory; (2) the company's retail capacity rate should be capped based on a value set by PJM; (3) the Commission should investigate whether I&M should exit the fixed

resource requirement (FRR) structure; and (4) the Commission should direct the company to develop a market-based retail capacity rate, beginning with the 2022-2023 planning period.

ABATE argued that, if I&M's capacity rate is not reduced, customer choice will likely be eliminated in the company's service territory. To remedy this, ABATE proposed a five-year average of the latest available zonal capacity prices for load because it best represents normalized test year value. If the Commission rejects the proposed five-year average, ABATE recommended that the Commission "unbundle the portion of I&M's fully embedded fixed production costs that is capacity related" and use "a proxy that is no higher than the PJM amortized net CONE value of \$288.95 per MW [megawatt]-day." ABATE's initial brief, p. 83.

In response, I&M explained that it is an FRR entity, which is a load-serving entity (LSE) that relies exclusively on its own capacity resources to meet its customers' electric load needs regardless of whether its customers take retail or wholesale service. I&M stated that "PJM's FRR provides a reasonable and equitable capacity charge by using the Company's actual cost of capacity" and recommended that the Commission adopt this capacity rate. I&M's initial brief, p. 76.

The company objected to the Staff's proposal, arguing that if the cost of capacity is based on the cost of a new CT plant, it fails to recognize that I&M is providing capacity to its Michigan retail customers with actual plants, owned and operated by I&M, and not a hypothetical CT plant. In addition, the company contended that if CONE is used to set the capacity rate, then the rate paid by open access distribution (OAD) customers will not fully reimburse I&M for its fully embedded production costs. As a result, the company stated that it will be forced to increase the rates paid by standard service customers, resulting in similarly-situated customers paying different rates for the

same capacity service and the creation of a subsidy for OAD customers. I&M asserted that “[s]uch a result would be highly discriminatory.” *Id.*, p. 77.

Similarly, if ABATE’s capacity rate proposal is approved, I&M claimed that other customers will be forced to subsidize OAD customers, which is “inconsistent with fundamental ratemaking principles that require customers to pay their respective actual costs.” *Id.*, p. 78. Regarding ABATE’s proposal to use a five-year average of the PJM RPM zonal capacity price or the PJM amortized net CONE of \$288.95 per MW-day, the company asserted that neither option would compensate I&M for the cost of capacity supplied to customers and, instead, would increase customer rates. Finally, in response to ABATE’s request that the Commission investigate whether the company should exit the FRR structure, I&M contended that this request is based on a vague suggestion in a previous case and recommended that it be rejected.

The ALJ found ABATE’s net CONE proposal to be the most reasonable method for calculating I&M’s capacity rate. He stated that net CONE is “essentially CONE with the small margin costs from energy and ancillary services removed.” PFD, p. 93. The ALJ noted that the net CONE method appears consistent with the Staff’s recommendation that only capacity-related costs, with an offset for market margins, are included in the capacity rate calculation.

I&M excepts, arguing that the methodology recommended by the ALJ has been rejected by the Commission and is contrary to statute. The company notes that, in Case No. U-17032, the Commission approved I&M’s cost-of-service-based capacity pricing proposal as the starting point for the state compensation mechanism, which was based on the company’s embedded costs. The company avers that its proposed capacity rate continues the cost-of-service-based method and it ensures that standard service customers and OAD customers will pay the same cost-based amount for capacity. I&M’s exceptions, pp. 3-4.

I&M also claims that the ALJ's recommendation violates Michigan law. MCL 460.11 states that the Commission shall set rates equal to the cost of providing service to each customer class. According to I&M, using net CONE to set the capacity rate denies the company an opportunity for full cost recovery because the capacity rate is less than the cost of I&M's capacity resources. I&M asserts that, pursuant to the ALJ's recommendation, OAD customers will pay net CONE and standard service customers will pay the company's embedded cost of capacity. I&M contends that the "Commission has expressly rejected the idea of having choice customers and bundled service customers pay differing capacity charges." *Id.*, p. 5.

Finally, the company alleges that there is no means for converting retail rates into dollars per MW-day as expressed by net CONE. Instead, I&M argues that using embedded capacity costs as the capacity charge "properly and directly translates into retail rates." *Id.*, p. 6.

In exceptions, ABATE states that, while net CONE is a reasonable and appropriate method for calculating I&M's capacity rate, the "five-year average of the latest available zonal capacity prices for load is the best choice" because: (1) there is considerable year-to-year variability in the PJM RPM zonal capacity prices; (2) it provides a normalized test year proxy; and (3) it unbundles the portion of fully embedded fixed production costs that are capacity-related. ABATE's exceptions, p. 9.

In addition, ABATE notes that the ALJ failed to address its request that the Commission investigate whether I&M should exit the FRR structure. According to ABATE, I&M would not have a capacity rate but for its choice of the FRR alternative. ABATE argues that I&M is not required to choose the FRR alternative over participation in the PJM capacity auctions and that I&M's revenue requirement is affected by the company's choice to use the FRR alternative.

Because it is unclear whether the FRR alternative presents a lower cost option, ABATE recommends that the Commission investigate whether I&M should exit the FRR structure.

Finally, ABATE renews its request that I&M be required to develop a market-based retail capacity rate beginning with the 2022-2023 planning year. ABATE states that the benefits of this proposal include less unnecessary construction and maintenance of generating facilities, the elimination of a proxy price for a capacity rate, and a reduction in capacity needs.

In reply, I&M reiterates that ABATE's net CONE proposal deprives the company of the opportunity to recover the cost of providing capacity service, it violates Michigan law, and it forces OAD customers to pay a different capacity rate than standard service customers.

Regarding ABATE's recommendation that the Commission direct the company to develop a market-based capacity rate, I&M argues that the mechanism in ABATE's proposal may not be available to alternative electric suppliers (AES) under the FRR structure. In addition, I&M asserts that ABATE's proposal may require the company to procure more capacity than necessary, thus needlessly increasing rates to all customers. Finally, I&M objects to ABATE's request that the Commission order an FRR investigation. The company states that ABATE's recommendation is not founded on evidence and is based on inaccurate competitive principles. I&M's replies to exceptions, pp. 10-11.

In replies to exceptions, the Staff recommends that the Commission adopt the ALJ's method for calculating the capacity rate because I&M's proposal inappropriately includes non-capacity-related costs. Moreover, the Staff disagrees that I&M's proposal is the only one that relies on embedded costs. Not only do both of the Staff's proposed methods rely on the company's embedded costs, but the Staff asserts that ABATE's net CONE proposal also relies on embedded costs. The Staff avers that "the issue is determining what portion of those embedded costs are

actually incurred to supply capacity service.” Staff’s replies to exceptions, p. 10. In the Staff’s opinion, the appropriate method for determining the portion of costs that are incurred to supply capacity is to identify production costs and then only consider those corresponding to the cost of a CT as capacity-related.

In response to I&M’s allegation that using net CONE will result in rates below the cost of service, thus creating a subsidy, the Staff argues that “this claim relies on the supposition that all production costs are incurred to provide capacity service, which Staff has shown to be untrue.” *Id.*, p. 11, citing Staff’s initial brief, pp. 63-64. And finally, replying to I&M’s claim that net CONE cannot be converted to a retail rate, the Staff explains that once appropriate production costs are determined, then a portion of those costs amounting to net CONE are considered capacity costs and this amount can be allocated to the classes on a 4CP basis to establish a retail rate.

The Staff asserts that ABATE’s proposal to use a five-year average of zonal capacity prices does not adequately reflect the company’s cost of providing capacity and is inconsistent with ratemaking principles in Michigan. The Staff also argues that ABATE’s request for a market-based alternative to the capacity charge “would result in discriminatory rates because certain similarly situated capacity customers could choose to pay the value of the service rather than the cost, leaving other customers to pick up the difference.” Staff’s replies to exceptions, p. 12.

ABATE contends that Michigan law and previous Commission decisions do not prohibit the use of net CONE to develop a capacity rate for I&M. ABATE states that the ALJ’s recommendation is based on the company’s embedded costs and “fully compensates I&M . . . because the capacity-related costs identified by using Net CONE are a fairly reasonable proxy for the price I&M would have to pay to acquire capacity.” ABATE’s replies to exceptions, p. 6.

ABATE also disputes I&M's allegation that net CONE creates a subsidy and prevents the company from fully recovering its capacity-related costs. According to ABATE, the costs allocated to standard service customers will not change unless rates are adjusted in a future rate case, thus eliminating the risk of a subsidy.

Regarding I&M's claim that it cannot convert net CONE dollars per MW-day into a retail rate, ABATE asserts that the company failed to provide a rationale for this argument. ABATE suggests that I&M may need to implement an improved billing system similar to those used by other Michigan utilities.

After evaluating the parties' positions, the Commission finds that the most reasonable method supported on the record for determining I&M's capacity rate is net CONE. The Commission notes that I&M has been an FRR entity since the inception of the RPM market in June 2007 under PJM's Reliability Resource Agreement (RRA). Among other things, the RRA establishes the capacity obligations of PJM LSEs and requires AESs to compensate I&M at a set capacity price. This non-bypassable capacity rate must be set by the FERC or at the state level.

On September 25, 2012, in Case No. U-17032 (September 25 order), the Commission set I&M's current capacity rate using embedded costs from the company's COSS. In that case, the Commission clearly stated that the COSS was "a starting point" and that "the capacity rate established in [Case No. U-17032] shall be reevaluated when I&M files its next general rate case." September 25 order, pp. 28-29. The immediate case is I&M's first rate case since Case No. U-17032 and, therefore, the Commission finds that I&M's capacity rate should be reevaluated in this case.

On December 21, 2016, Public Act 341 (Act 341) was signed into law, which amended MCL 460.1 *et seq.*, to include Section 6w. Section 6w(3) of Act 341 requires the Commission to

establish a capacity rate to be applied to alternative electric load that is not exempt under subsections (6) and (7). To determine the capacity rate, Section 6w(3)(a) and (b) state that the Commission shall: (1) include the capacity-related generation costs included in the utility's base rates, surcharges, and PSCR factors; and (2) subtract all non-capacity-related electric generation costs.

Section 6w(11) clarifies that Act 341 does not prevent the Commission from determining a generation capacity charge under the PJM framework. Specifically, the statute states:

Nothing in this act shall prevent the commission from determining a generation capacity charge under the reliability assurance agreement, rate schedule FERC No. 44 of the independent system operator known as PJM Interconnection, LLC, as approved by the Federal Energy Regulatory Commission in docket no. ER10-2710 or similar successor tariff.

MCL 460.6w(11). The Commission agrees with the company that nothing in Act 341 requires that I&M's capacity rate be set using the mechanism set forth in the statute. Although the Commission notes that the capacity charge methodology set forth Section 6w(3) may not directly apply to I&M, subsections (a) and (b) of Section 6w(3) provide guidance to the Commission for determining capacity costs and rates. Based on this guidance and the evidence in this case about an equitable and accurate rate for capacity, the Commission finds it appropriate to revisit the methodology approved by the Commission in Case No. U-17032.

The Commission agrees with the Staff that, because I&M's current capacity rate improperly includes some production-demand classified costs that are not capacity-related, it should be rejected. By contrast, the Commission finds that, based on the record in this case, net CONE can be used to appropriately identify what portion of production costs are actually incurred to supply capacity.

As explained by ABATE, net CONE is the amortized net cost of a new CT generation facility. This peaking generation is the lowest cost utility generation that can provide capacity and, therefore, it is a good proxy for the cost I&M would incur if it constructed generation principally for the purpose of providing capacity. In addition, using net CONE removes the limited energy and ancillary service margins that are not directly related to capacity service. The Commission finds this proposed method, which begins with total embedded production-related costs and subtracts non-capacity-related costs, to be reasonable.

The Commission notes that its decision must be based on the evidentiary record before it and is constrained by the testimony, exhibits, arguments, facts, and circumstances presented in this case. The Commission may revisit, in a future rate case, whether to retain this net CONE methodology or use an approach that more closely aligns with the capacity charge methodology approved in Case Nos. U-18239 and U-18248 (i.e., using fixed costs offset by fuel and other revenues).

The Commission finds unpersuasive I&M's claim that, if net CONE is used to set the capacity rate, rates will differ between OAD customers and standard service customers, thus resulting in a subsidy. As explained by the Staff, the company incorrectly assumes that all production capacity-related costs are incurred to provide capacity. The attachments to this order demonstrate that the rates calculated for OAD and standard service customers using net CONE do not differ.

The Commission rejects ABATE's request to investigate whether I&M should exit the FRR structure. The Commission finds that ABATE failed to provide evidence demonstrating that I&M's designation as an FRR results in higher rates for customers. Thus, there is no issue warranting a Commission investigation.

The Commission also agrees with the Staff that ABATE's request for a market-based alternative to the capacity charge should be denied. ABATE's proposal would result in discriminatory rates because similarly-situated customers could choose to pay for the value of the service, rather than the cost, and other customers could be forced to make up the difference.

Finally, the Commission finds the Staff's suggestion for converting net CONE to a retail rate to be reasonable and adopts the Staff's calculation. The Commission notes that PJM already calculates an amortized net CONE value for the AEP Zone as part of its RPM auction process. For the 2018-2019 delivery year, this value is \$288.95/MW-day, and the Commission finds that this price should be approved as I&M's capacity rate.

C. Revenue Allocation and Implementation of the Modified Rate Realignment Surcharge

I&M proposed to modify the existing rate realignment surcharge (RRS) that was approved in Case No. U-16180 and revised in Case Nos. U-16801 and U-17698. ABATE objected, asserting that the company's proposed revenue distribution process should "be rejected because it arbitrarily and inappropriately includes an overpayment (subsidy) in the Rate LP rate design that will continue for decades." 3 Tr 992. In ABATE's opinion, the revised RRS amounts to a subsidy mechanism designed to prevent a rate increase for any class greater than 2.5% above the average increase requested in this case.

Responding to ABATE, I&M argued that if the RRS is eliminated, four tariff classes will receive rate increases greater than 20%, with one class receiving an increase of more than 40% and another of more than 130%. Accordingly, the company stated that if the surcharge is reset based on the figures set forth by I&M in this case, it will maintain "the same 2.5% level of per-year maximum class increase as implemented in those earlier cases." I&M's initial brief, p. 75.

Although the Staff agreed with I&M that limits should be imposed on excessive rate class increases, the Staff expressed concern that a 2.5% rate cap may impede the goal of reaching actual cost-of-service levels for rate classes. Therefore, to avoid rate shock, the Staff recommended increasing the rate cap to a maximum of 25% for any of the rates initially approved in this case, and the increases in years after the initial year should not exceed 10% for any rate schedule.

Following the amendment of 2008 PA 286 by Act 341, the ALJ noted that MCL 460.11(1) now states that:

the commission shall ensure the establishment of electric rates equal to the cost of providing service to each customer class. In establishing cost of service rates, the commission shall ensure that each class, or sub-class, is assessed for its fair and equitable use of the electric grid. If the commission determines that the impact of imposing cost of service rates on customers of an electric utility would have a material impact on customer rates, the commission may approve an order that implements those rates over a suitable number of years.

Therefore, pursuant to Act 341, the ALJ found that the previous 2.5% cap may be replaced with a more reasonable figure. The ALJ agreed with ABATE that extending the effects of the rate cap over a 28-year period is unreasonably long; however, elimination of the cap could lead to an immediate rate increase of as much as 130% for some customers. As a result, the ALJ determined that the Staff's proposed "RRS that restricts the increases assigned to any rate schedule as a result of this proceeding to no more than 25% above its current level" is the most reasonable and should be adopted. PFD, p. 95.

The Staff excepts, contending that the ALJ may have misunderstood the Staff's position. For the purpose of providing clarification, the Staff states that it "proposed a cap of 25% on the total increase to a class resulting from this case (approximately 5% over the average increase), including both the RRS and the approved rate increase not related to the RRS, and a limit of 10% for years after the initial year (relating only to the RRS)." Staff's exceptions, p. 2.

In exceptions, the Attorney General recognizes the concerns regarding the longevity of the rate cap. However, he requests that the Commission consider that if I&M's rate relief is granted, it will result in a significant rate increase, especially for residential customers. The Attorney General recommends that any adjustments to the rate cap "should be limited to avoid rate-shock from occurring." Attorney General's exceptions, p. 29.

The Commission finds that the ALJ's recommendation should be adopted, with the Staff's clarification set forth in exceptions. Section 11(1) of Act 341 allows the Commission to modify the rate cap, while ensuring that rates move toward the actual cost of service without a "material impact" on customer rates. As pointed out by ABATE, continuing the previous 2.5% rate cap would extend rate class subsidies for an unreasonable amount of time. On the other hand, the Commission recognizes the extreme rate shock that is likely to be experienced by some of I&M's customers if the cap is eliminated. Therefore, the Commission adopts the Staff's proposed cap of 25% on the total increase to a class resulting from this case (approximately 5% over the average increase), including both the RRS and the approved rate increase not related to the RRS, and a limit of 10% for years after the initial year (relating only to the RRS).

X. RATE DESIGN AND OTHER TARIFF ISSUES

I&M requested the continuation of several Tariff Book No. 15 riders, some of which the company proposed to modify, and the addition of two new riders. The company also proposed updates to several sections of its basic tariffs in Tariff Book No. 16. I&M stated that the tariff modifications are set forth in Exhibit IM-47 through IM-50, IM-110 through IM-112.

The ALJ noted that no party objected to these tariff modifications or the company's slight revisions to its existing PSCR program, the RRS (beyond the issues addressed above), the energy optimization surcharge, the nuclear decommissioning surcharge, the renewable energy surcharge,

the EDR, and the low-income energy assistance fund surcharge. The ALJ found I&M's proposed amendments and updates to be reasonable and recommended adoption by the Commission.

However, the ALJ found the company's request to "dramatically increase its Special Services Charges" to be unreasonable. Quoting the Staff, the ALJ noted:

as shown in Exhibit IM-111 (KCC-6), Page 2, the charge for reconnecting when disconnect is required at vault, manhole, or service box nearly triples. In the interest of phasing in these large increases and limiting the impact to customers, Staff recommends that the increases to special charges be capped at 25%.

PFD, p. 98, quoting 3 Tr 1282. The ALJ stated that, in the interest of gradualism, the Staff's proposed 25% cap on increases should be approved.

No exceptions were filed and, therefore, the Commission adopts the ALJ's findings and recommendation.

A. Net Lost Revenue Tracker

I&M requested approval to implement a NLR tracker to recover lost sales revenues that result from the company's "implementation of energy waste reduction [EWR] conservation, demand-side [management] programs, and other waste reduction measures." I&M's initial brief, p. 87.

The Staff objected, noting that the NLR tracker is essentially an RDM. According to the Staff, I&M's proposed NLR tracker allows the company to recover revenue even if its revenues increase through other sales. And, the Staff asserted, the NLR tracker lacks a cap and, as a result, "has the potential to accumulate vast sums over time." Staff's reply brief, p. 58. As an alternative, the Staff proposed a multi-step calculation that includes an initial threshold requirement to "qualify for net lost revenue recovery, a 3% cap on the total cumulative net lost revenues" that are recoverable by the NLR tracker, and "a methodology to compute lost sales for a given year." I&M's initial brief, p. 88. Pursuant to the Staff's method, I&M is required to demonstrate that its actual sales

declined from the projected levels in the last rate case and that the clear decline limits the ultimate recovery provided for under the NLR tracker.

The ALJ recommended Commission approval of the Staff's proposal. The ALJ asserted that, "Without a cap (which the Company's NLR Tracker lacks), there is, as the Staff's [sic] notes, a danger that significant variability in price 'could threaten public acceptance of decoupling and the broader policy objectives it serves.'" PFD, p. 99, quoting Staff's initial brief, pp. 76-77. The ALJ found that, pursuant to the Staff's proposal, each rate class is responsible for paying its fair share of the costs and no more. The ALJ noted that the Staff's mechanism would end when I&M files its next general rate case and the company would need to file an updated RDM in order to recover any future EWR-related lost revenue.

In exceptions, I&M argues that the Staff's proposal overreaches and is overly burdensome for several reasons. I&M opines that a cap on lost revenues is unwarranted and creates an incentive for the company to file a new rate case. In addition, the company states that, "while knowing in advance that a tracker will expire when a new rate case is filed at least provides the utility with proper notice, renewing a tracker instead of updating the inputs is an unnecessary administrative burden." I&M's exceptions, p. 36.

I&M also disputes the Staff's claim that MCL 460.6a(13) supports mechanisms which aggregate revenues and allow for recovery only if overall revenue is lost. According to the company, the statute directs the Commission to consider "aggregate revenues attributable to revenue mechanisms;" nowhere does it state that the Commission should consider revenues from sources other than those produced by the revenue mechanism. *Id.*, quoting MCL 460.6a(13). I&M asserts that the Staff's proposal to consider revenues from other sources is overly complicated. By contrast, the company states that its proposal is simple, is limited to recovering

certified lost revenue that is directly attributable to EWR programs, and reduces the need to file rate cases.

In reply, the Staff reiterates that establishing a cap on lost revenues protects customers from significant variability in prices. Additionally, the Staff states that it is important that I&M file for a new or continued RDM in its next general rate case because “filing for new rates allows the Company to ‘true-up’ any outstanding revenue shortfalls. Also, nuances can arise over time and may alter the Company’s RDM ideas within each general rate case.” Staff’s replies to exceptions, p. 15.

The Attorney General does not support approval of the NLR tracker. However, in the event the Commission approves the mechanism, he recommends that the Commission should further reduce the company’s ROE because the NLR tracker helps to reduce the risk of revenue losses.

The Commission agrees with the ALJ that the Staff’s proposal should be approved. The Staff’s proposed RDM mechanism calculates the portion of overall revenue loss attributable to EWR programs. Only sales losses attributable to EWR program savings are eligible for recovery in the RDM and only if I&M achieves Act 341’s minimum annual incremental energy savings. Also, as argued by the Staff, a cap is necessary to protect customers from significant price variability and to ensure that the mechanism does not amass excessive amounts. The Commission finds that the Staff’s proposed RDM is limited in scope, eliminates the company’s disincentive to offer EWR programs, appropriately complies with Act 341, and ensures that ratepayers are charged a reasonable amount *only* when there is a shortfall. Therefore, the Commission adopts the Staff’s proposed alternative RDM mechanism and overall financial cap.

B. Economic Development Rider

I&M proposed an EDR, stating that it:

replaces the Company's expired EDR and will incorporate qualifying measures and incentives to attract a wide array of new business and industry to I&M's service area in Michigan. This new business will assist the state and local governments by bringing in additional tax revenues to fund needed infrastructure improvements, as well as help other I&M customers by spreading the Company's fixed costs over a larger customer base.

I&M's initial brief, p. 85 (citations omitted). No party objected to the company's proposal. The ALJ found the proposed EDR reasonable and recommended Commission approval.

No exceptions were filed and, therefore, the Commission adopts the ALJ's findings and recommendation.

C. Low-Income Rate and Related Cost Deferral

I&M proposed to add a new low-income tariff provision, the Low-Income Cost Recovery Surcharge. However, the company will not include the provision in its tariff book. Instead, I&M explained that it will initially defer revenue shortfall arising from the low-income customer rate and, once participation levels are known, the company will request a rider to collect the deferred and ongoing costs on a per-meter charge applicable to all customer classes. I&M proposes to reconcile and update the Low-Income Cost Recovery Surcharge rate on an annual basis. No party objected to the company's proposal.

The ALJ stated that, "because I&M's suggested implementation of a discounted low income service rate appears to be consistent with Act 341 . . . it should be adopted in this case." PFD, p. 102.

No exceptions were filed and, therefore, the Commission adopts the ALJ's findings and recommendation.

D. Residential Customer Charge/Senior Citizen Rate

In order to establish a service charge for residential customers that more accurately reflects the company's actual costs of connecting a customer to the system, I&M proposed increasing its general residential customers' monthly service charge from a flat rate of \$7.25 per month to \$18.00. However, the company stated that for senior citizens taking service on Rate SC, the rate would only increase to \$9.00 per month.

The Staff objected, stating that I&M's customer charge included both embedded and marginal costs of meters and service drops used to connect residential customers to the system. According to the Staff, to "calculate its system-wide marginal distribution costs for these meters and services, the company used actual 2016 costs and weighted them based on the ratio of overhead to underground installations." Staff's initial brief, pp. 69-70 (citations omitted). However, the Staff contends that this method inaccurately represents system-wide costs because it fails to recognize the actual ratio of connection types present in its entire system, which includes connections installed decades ago. Although I&M stated that its current costs are equivalent to marginal costs on an average basis, the Staff asserted that the company failed to prove that these costs have not already been recovered through the company's special charges, which include fees for these connections. Therefore, the Staff contended that "including the full costs of installing meters and service drops in the customer charge would double charge ratepayers." *Id.*, p. 71.

And, contrary to I&M's claim that current marginal costs are the same as overall marginal costs, the Staff argued that there is a significant difference between the two. The Staff explained that:

The difference is evident when comparing current marginal costs of installing underground lines instead of overhead lines (in light of the current installation ratio of underground to overhead installations) with the overall marginal costs (in light of the historical installation ratio). The marginal cost of installing underground lines

is 3.5 times more than the cost of installing an overhead connection. The Company, continuing to confuse current with marginal, assumed its 2016 installation rate of 80/20 underground to overhead connections applied to the costs of all its existing connections (e.g., those connected 20 years ago and those connected last year). This is inappropriate. In reality, it has far less impact on its historical and overall connection costs because historically the Company installed fewer underground lines and more overhead lines.

Id., pp. 72-73. According to the Staff, the company's error inflates its customer charge by overstating the marginal cost of connection, whereas the Staff's embedded cost is functionally equivalent to the overall marginal cost of connections and "includes only costs directly related to supplying service to the customer, including meters, services, and customer service." 3 Tr 1168.

The Staff noted that its COSS shows that the customer charge should only be \$7.09 per month. Rather than reducing I&M's charge from its current level, the Staff proposed leaving the charge at \$7.25 per month because the difference between the current charge and the charge produced by the Staff's COSS is minimal.

The Attorney General agreed with the Staff, stating that I&M's "computation of customer-related costs was over inclusive and not truly representative of the embedded costs on its system." 3 Tr 1166. He requested that the Commission reject the company's proposal to increase the service charge.

The ALJ compared I&M's and the Staff's competing COSSs and found it most reasonable to adopt the Staff's proposal to continue the residential customer service charge at the current level of \$7.25 per month. He stated that "Due to the multiple rate changes that will likely result from this case . . . retaining the customer charge at its current level would appear to be beneficial to ratepayers by reducing—at least somewhat—the customer confusion that may well ensue from the large array of options that will be provided for by way of the final order in this case." PFD, p. 104. In addition, he found persuasive the Staff's position that the costs in question are already

being recovered through special charges and that there is a significant difference between current marginal costs and overall marginal costs.

In exceptions, I&M argues that its methodology considers both its embedded customer-related O&M costs and its marginal (or current) costs of meters and service drops currently required to connect a customer to its system. The company avers that it “properly calculated those costs to reflect that the marginal costs represent a portion of the Company’s average embedded customer-related costs” and, therefore, it is not a double recovery. I&M’s exceptions, p. 40. I&M reiterates that the purpose of the increase is to adjust charges to more accurately reflect the company’s costs.

Although the Staff agrees with the ALJ’s conclusion regarding the residential customer charge, the Staff asserts that he may have made a minor misstatement. The Staff notes that, in regards to the costs used to calculate I&M’s residential customer charge, the ALJ stated that he “does not believe that the utility failed to prove that the costs in question are not already (or will not be in the future) recovered through the ‘special charges’ addressed above, which include those relating to electric connections.” Staff’s exceptions, p. 3, quoting PFD, p. 105. According to the Staff, the ALJ used language similar to the Staff’s argument, but misstated the intent. Based on the content of the ALJ’s recommendation, the Staff believes that the ALJ intended to write: “The ALJ does not believe that the utility proved that the costs in question are not already (or will not be in the future) recovered through the ‘special charges’ addressed above, which include those relating to electric connections.” *Id.*

In reply to I&M, the Staff states that the company once again conflates current and marginal costs, an error already addressed by the Staff. The Staff reiterates that its proposed embedded cost is functionally equivalent to the overall marginal cost of connections and only includes costs directly related to providing service to the customer. The Attorney General agrees.

The Commission finds persuasive the ALJ's findings and recommendation. Regarding I&M's assertion that its current costs are equivalent to marginal costs on an average basis, the Commission agrees with the Staff that the company failed to prove that these costs have not already been recovered through the company's special charges, which include fees for these connections. In addition, the Commission finds that the company incorrectly claims that its current marginal costs are equivalent to its overall marginal costs. As pointed out by the Staff, the current marginal costs of installing underground lines, instead of overhead lines, is 3.5 times more. *See*, 3 Tr 1167. The company's current connection type ratio is not reflective of the actual connection ratio embedded in its system. Thus, contrary to the company's claim, its current marginal costs are not equivalent to overall marginal costs and the error inflates I&M's customer charge.

The Commission agrees with the ALJ that, after considering I&M's and the Staff's COSSs and other rate changes in this case, it is reasonable and prudent to continue the residential customer charge at its current level of \$7.25 per month.

E. General Service Customer Charge

Although the PFD implicitly recommended approval of the Staff's customer charge methodology, it was discussed only in relation to the residential rate schedules. The Commission notes that the ALJ inadvertently omitted a recommendation regarding the General Service (GS) customer charge because it was not directly addressed by the parties. Based on a limited record, the Commission must determine how the customer charge should be applied to the Small General Service (SGS) and secondary Medium General Service (MGS) rate schedules.

In testimony, I&M proposed combining the SGS and MGS rate schedules into a new GS schedule. 3 Tr 795-796. For the new rate schedule, the company recommended a single customer

charge for former SGS customers and former secondary MGS customers. *See*, Exhibit A-6, Schedule F3. I&M asserted that “no customer charge resulting from this case should be lower than the current customer charge for any particular tariff class” as it relates to the non-residential classes. 3 Tr 805. This is generally consistent with the Staff’s recommendation relating to the residential customer charge.

In exhibits, the Staff also proposed a single customer charge for the SGS and MGS rate schedules. However, the Staff based its recommendation on the cost-based customer charge for former SGS customers. Exhibit S-6, Schedule F3 and Exhibit S-19.4.

The Commission finds that the Staff’s proposal reduces the customer charge for those formerly on the MGS rate schedule below the current charge without justification based on cost. In addition, the cost-based customer charge for combined secondary MGS and SGS customers would be \$8.21,³ which is lower than the current secondary MGS customer charge.

The Commission finds that adopting I&M’s proposal, with minor modification, will ensure that the customer charge for SGS and secondary MGS customers is not reduced below the current customer charge for any particular tariff class. The Commission finds the company’s proposal to consolidate SGS and secondary MGS customers into a single rate schedule, Tariff GS, to be reasonable and prudent. And, for purposes of applying the customer charge, the Commission finds that I&M’s proposal effectively differentiates between current secondary MGS customers and SGS customers: customers with 4,500 kilowatt-hour (kWh), or less, average monthly usage (former SGS customers) will not receive a demand meter and customers with more than 4,500 kWh average monthly usage (former secondary MGS customers) should receive a demand meter. 3 Tr 795-796. However, rather than applying a single customer charge to both customer groups,

³ *See*, Exhibit S-19.4 $(\$1,084,193 + \$637,374) / (162,112 + 47,693) = \8.21 .

the Commission finds that I&M's current SGS customer charge should apply to customers without a demand meter and the company's current secondary MGS customer charge should apply to customers with a demand meter.

The Commission cautions I&M, however, to carefully consider the current tariff language permitting the company to install demand meters at its discretion. Installation of a demand meter for a customer averaging under 4,500 kWh a month will be scrutinized in the company's next rate case.

F. Open Access Distribution Tariff Modifications

To add customer protections to I&M's OAD tariff, the Staff is:

1) recommending an early termination fee cap of \$50 for contract terms with one year or less and \$100 for contract terms longer than one year for residential customers; 2) recommending appropriate contract verification from the residential account holder or legally authorized person on the account; 3) recommending a five business day Staff review period for all residential contracts and marketing materials; 4) recommending that a confirmation letter and contract if applicable, be U.S. mailed from the AES to the residential account holder or legally authorized person within 7 days of signing a contract and; 5) recommending a 14-day notice period in which residential customers may cancel their enrollment before their switch is executed.

3 Tr 1128. In addition, the Staff requested that the Commission adopt the proposed modifications to the company's OAD tariff as set forth on pages 1 through 3 of Exhibit S-17. The Staff acknowledged that the modifications are unique, but argued that they will help a customer more safely purchase a block of power from an AES. Finally, the Staff proposed that I&M update its OAD tariff to include language specifically explaining when an AES customer is subject to a capacity charge. No party objected to the Staff's proposal.

The ALJ found the Staff's proposed modifications reasonable and recommended Commission approval.

No exceptions were filed and, therefore, the Commission adopts the ALJ's findings and recommendation.

THEREFORE, IT IS ORDERED that:

A. Based on this order's findings adopting a projected calendar test year ending December 31, 2018, a jurisdictional rate base of \$984,631,0000, an authorized rate of return on common equity of 9.90%, and an overall rate of return of 5.76%, Indiana Michigan Power Company is authorized to implement rates that increase its annual electric revenues by \$49,118,000 on a jurisdictional basis over the rates approved on February 15, 2012, in Case No. U-16801.

B. Indiana Michigan Power Company shall implement a state reliability mechanism capacity charge of \$105,467 per megawatt-year, or \$288.95 per megawatt-day, for full-service customers.

C. Indiana Michigan Power Company is authorized to implement the rates approved by this order on a service rendered basis for service provided on and after April 26, 2018, as summarized in Attachment A, and set forth in Attachment B. Within 30 days of April 12, 2018, Indiana Michigan Power Company shall file tariff sheets substantially similar to those contained in Attachment B. Due to the size of Attachment B, it is not physically attached to the original order contained in the official docket or paper copies of the order, but is electronically appended to this order, which is available on the Commission's website. Attachment C contains a calculation of the capacity charge as updated by this order. Attachment D contains the rate realignment surcharge schedule.

D. Indiana Michigan Power Company shall submit a draft distribution investment and maintenance plan to the Commission Staff by October 31, 2018. Subsequently, the company shall meet with the Staff to discuss the framework for completing a final five-year distribution investment and maintenance plan to be submitted by May 1, 2019, in Case No. U-20147.

E. In future rate cases, Indiana Michigan Power Company shall provide a detailed analysis of the projected and actual incurred costs for cybersecurity projects, as set forth in this order.

F. Indiana Michigan Power Company is authorized to establish a regulatory asset for the difference between the Rockport Unit 2 depreciation expense recorded on the company's books using a 2022 retirement date and depreciation expense used for ratemaking using a 2028 retirement date, as described in this order.

G. Upon termination of the lease for Rockport Unit 2, Indiana Michigan Power Company shall amortize the regulatory asset through the 2028 retirement date used for setting Rockport Unit 2 depreciation expense for base rates in this case.

H. As required by the February 22, 2018 order in Case No. U-18494, Indiana Michigan Power Company shall file a Credit A application no later than May 14, 2018, in Case No. U-20107.

I. Indiana Michigan Power Company is authorized to adopt a revenue decoupling mechanism, as described in this order.

J. Indiana Michigan Power Company shall modify the existing rate realignment surcharge, as described in this order.

K. Indiana Michigan Power Company shall modify and add two new riders to the Tariff Book No. 15 riders, update basic tariffs in Tariff Book No. 16, and modify its Special Services Charge, as described in this order.

L. Indiana Michigan Power Company shall implement an economic development rider and a Low-Income Cost Recovery surcharge, as described in this order.

M. Indiana Michigan Power Company shall implement the open access distribution tariff modifications, as described by this order.

N. Indiana Michigan Power Company's residential customer charge shall remain at the current level of \$7.25 per month.

O. Indiana Michigan Power Company's accounting requests are approved as set forth in the order.

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

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, under MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General - Public Service Division at pungpl@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 April 12, 2018.

Kavita Kale, Executive Secretary

Line No.	Class Description	Total Present Revenue	Total Proposed Revenue	Total Net Increase / (Decrease)	Total Net Increase / (Decrease) (%)
	(a)	(b)	(c)	(d)	(e)
1	RS *	122,511,136	147,744,116	25,232,980	20.60%
2	RS-TOD *	8,226,851	10,033,572	1,806,721	21.96%
3	RS-OPES *	1,235,510	1,619,736	384,226	31.10%
4	RS-TOD2 *	2,590	3,200	610	23.55%
5	RS-SC	913,949	1,186,677	272,728	29.84%
6	Total Residential	132,890,036	160,587,301	27,697,265	20.84%
7					
8	SGS	13,567,871	13,975,073	407,202	3.00%
9	SGS-Unmetered	138,746	140,402	1,656	1.19%
10	SGS-LM-TOD	10,253	11,915	1,662	16.21%
11	SGS-TOD2	61,663	70,436	8,773	14.23%
12	Total SGS	13,778,533	14,197,826	419,293	3.04%
13					
14	MGS Sec	50,093,154	62,460,103	12,366,949	24.69%
15	MGS-TOD	950,019	1,243,943	293,924	30.94%
16	MGS-LM-TOD	66,949	87,497	20,548	30.69%
17	MGS Pri	8,278,240	10,265,621	1,987,381	24.01%
18	MGS Sub	1,106,101	1,369,313	263,212	23.80%
19	Total MGS	60,494,463	75,426,477	14,932,014	24.68%
20					
21	LGS - Sec	11,088,562	12,853,190	1,764,628	15.91%
22	LGS - Pri	12,722,769	14,381,552	1,658,783	13.04%
23	LGS - Sub	0	-	-	0.00%
24	LGS-LM-TOD	234,209	320,259	86,050	36.74%
25	Total LGS	24,045,540	27,555,001	3,509,461	14.60%
26					
27	LP-Pri	26,419,595	27,826,478	1,406,883	5.33%
28	LP-Sub	19,342,707	20,138,222	795,515	4.11%
29	LP-Tran	5,712,698	6,040,706	328,008	5.74%
30	Total LP	51,475,000	54,005,406	2,530,406	4.92%
31					
32	EHG	415,648	27,604 X	(388,044)	-93.36%
33	EHS	474,577	592,880 X	118,303	24.93%
34	IS	1,153,568	1,402,581 X	249,013	21.59%
35	MS	2,485,804	2,942,371 X	456,567	18.37%
36					
37	WSS-Sec	1,119,775	1,283,012	163,237	14.58%
38	WSS-Pri	1,156,205	1,286,370	130,165	11.26%
39	Total WSS	2,275,980	2,569,382	293,402	12.89%
40					
41	OSL	1,854,633	2,015,760 X	161,127	8.69%
42	SLS	500,880	444,119	(56,761)	-11.33%
43	SLC	43,910	33,175	(10,735)	-24.45%
44	ECLS	628,438	605,738	(22,700)	-3.61%
45	SLCM	38,254	36,582	(1,672)	-4.37%
46	Total Lighting	3,066,115	3,135,374	69,259	2.26%
47					
48	Total	292,555,264	342,442,203	49,886,939	17.05%

M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)

INDIANA MICHIGAN POWER COMPANY

<http://www.indianamichiganpower.com/>

SCHEDULE OF TARIFFS GOVERNING THE SALE OF ELECTRICITY

Copies of I&M's Rate Book for Electric Services are available on
Indiana Michigan Power's website at this following website address,
<http://www.aep.com> or at the Michigan Public Service Commission website
at <http://www.michigan.gov/mpsc/0,1607,7-159-16370---,00.html>.

APPLYING TO THE FOLLOWING TERRITORY:
Allegan, Berrien, Cass, Kalamazoo, St. Joseph,
and Van Buren Counties, Michigan

THIS RATE BOOK SUPERSEDES AND CANCELS RATE BOOK M.P.S.C NO. 15 - ELECTRIC

ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER

ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**INDEX
SECTION A**

TARIFF	DESCRIPTION	SHEET NO(S).
	Title Page	A-1.00
	Index	A-2.00 – A-6.00
	Table of Contents - Checklists	A-7.00 – A-12.00
	Area Map of Localities Where Electric Service is Available	A-13.00
	Localities Where Electric Service is Available	A-14.00
	Abbreviations, Technical Terms and Definitions	A-15.00-18.00

SECTION B

MICHIGAN PUBLIC SERVICE ADMINISTRATIVE RULES INDEX

http://www.michigan.gov/lara/0,4601,7-154-35738_10806-271924--,00.htm

B1	CONSUMER STANDARDS AND BILLING PRACTICES FOR ELECTRIC RESIDENTIAL SERVICE (R 460.101 - R 460.169) http://w3.lara.state.mi.us/orrsearch/107_92_AdminCode.pdf	B-1.00
B2	TECHNICAL STANDARDS FOR ELECTRIC SERVICE (R 460.3101 – 460.3804) (FOR ALL CUSTOMERS) http://w3.lara.state.mi.us/orrsearch/108_11_AdminCode.pdf	B-4.00
B3	BILLING PRACTICES APPLICABLE TO NON-RESIDENTIAL ELECTRIC AND GAS CUSTOMERS (R 460.1601 – 460.1640) http://w3.lara.state.mi.us/orrsearch/108_03_AdminCode.pdf	B-6.00
B4	ELECTRIC SUPPLY AND COMMUNICATONS LINES AND ASSOCIATED EQUIPMENT (R 460.811 – 460.814) http://w3.lara.state.mi.us/orrsearch/107_99_AdminCode.pdf	B-8.00
B5	ELECTRIC INTERCONNECTION AND NET METERING STANDARDS (R 460.601 – 460.656) http://w3.lara.state.mi.us/orrsearch/107_97_AdminCode.pdf	B-8.00

(Continued on Sheet No. A-3.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

(Continued from Sheet No. A-2.00)

B6	SERVICE QUALITY AND RELIABILITY STANDARDS FOR ELECTRIC DISTRIBUTION SYSTEMS (R 460.701 – 460.752) http://w3.lara.state.mi.us/orrsearch/107_98_AdminCode.pdf	B-9.00
B7	UNDERGROUND ELECTRIC LINES (R 460.511 – 460.519) http://w3.lara.state.mi.us/orrsearch/107_96_AdminCode.pdf	B-10.00
B8	UNCOLLECTIBLES ALLOWANCE RECOVERY FUND (R 460.2601 - 460.2625) Rescinded November 12, 2013 http://w3.lara.state.mi.us/orrsearch/108_09_AdminCode.pdf	B-11.00
B9	PRACTICE AND PROCEDURE BEFORE THE COMMISSION (R 460.17101-460.17701) http://w3.lara.state.mi.us/orrsearch/934_2009-046LR_AdminCode.pdf	B-11.00
B10	FILING PROCEDURES FOR ELECTRIC, WATER, STEAM AND GAS UTILITIES (R 460.2011 – 460.2031) http://w3.lara.state.mi.us/orrsearch/832_10798_AdminCode.pdf	B-11.00
B11	RESIDENTIAL CONSERVATION PROGRAM STANDARDS (R 460.2401 – 460.2414) http://w3.lara.state.mi.us/orrsearch/835_10801_AdminCode.pdf	B-11.00
B12	PRESERVATION OF RECORDS OF ELECTRIC, GAS AND WATER UTILITIES (R 460.2501 – 460.2582) http://w3.lara.state.mi.us/orrsearch/836_10802_AdminCode.pdf	B-11.00
B13	UNIFORM SYSTEM OF ACCOUNTS FOR MAJOR AND NON MAJOR ELECTRIC UTILITIES (R 460.9001- 460.9019) http://w3.lara.state.mi.us/orrsearch/108_12_AdminCode.pdf	B-12.00
B14	RATE CASE FILING REQUIREMENTS FOR MAJOR ELECTRIC UTILITIES http://www.cis.state.mi.us/mpsc/orders/archive/pdfs/U-4771_05-10-1976.PDF	B-12.00
B15	RULES AND REGULATIONS GOVERNING ANIMAL CONTACT CURRENT MITIGATION (R 460.2701 – 460.2707) http://w3.lara.state.mi.us/orrsearch/108_10_AdminCode.pdf	B-12.00

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. A-4.00

(Continued from Sheet No. A-3.00)

**SECTION C
TERMS AND CONDITIONS OF STANDARD SERVICE**

	DESCRIPTION	SHEET NO(S).
	Indiana Michigan Power Terms and Conditions of Standard Service	C-1.00 - C-19.00

**SECTION D
STANDARD SERVICE AND OPEN ACCESS DISTRIBUTION SERVICE TARIFFS**

TARIFF	DESCRIPTION	SHEET NO(S).
	Title Page	D-1.00
RS	Residential Electric Service	D-2.00 - D-5.00
RS-TOD	Residential Time-of-Day Service	D-6.00 - D-7.00
RS-OPES/PEV	Residential Off-Peak Energy Storage/Plug-In Electric Vehicle	D-8.00 - D-9.00
RS-TOD2	Residential - Time-of-Day 2 Service	D-10.00 – D-11.00
RS-SC	Optional Residential Senior Citizen	D-12.00 - D-15.00
GS	General Service	D-16.00 - D-20.00
GS-TOD	General Service - Time-of-Day Service	D-21.00 – D-22.00
GS-TOD2	General Service - Time-of-Day 2 Service	D-23.00 - D-24.00
LGS	Large General Service	D-25.00 - D-29.00
LP	Large Power	D-30.00 - D-34.00
MS	Municipal and School Service	D-35.00 - D-36.00
WSS	Water and Sewage Service	D-37.00 - D-40.00
EHS	Electric Heating Schools	D-41.00 - D-43.00
IS	Irrigation Service	D-44.00 - D-45.00
OSL	Outdoor Security Lighting	D-46.00 - D-49.00
SLS	Streetlighting Service	D-50.00 - D-52.00
SLC	Streetlighting - Customer-Owned System	D-53.00 - D-55.00
ECLS	Energy Conservation Lighting Service	D-56.00 - D-59.00
SLCM	Streetlighting - Customer-Owned System - Metered	D-60.00 - D-61.00
COGEN/SPP	Cogeneration and/or Small Power Production Service	D-62.00 - D-68.00
CATV	Pole Attachment Rental - Cable Television	D-69.00 - D-70.00
CS-IRP	Contract Service – Interruptible Power	D-71.00 - D-72.00

(Continued on Sheet No. A-5.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

(Continued from Sheet No. A-4.00)

**SECTION D (continued)
STANDARD SERVICE AND OPEN ACCESS DISTRIBUTION SERVICE TARIFFS**

RIDER	DESCRIPTION	SHEET NO(S).
	STANDARD RIDERS	
AFS	Rider AFS - Alternate Feed Service	D-73.00 - D-76.00
EDR	Economic Development Rider To Tariffs GS, LGS and LP	D-77.00 - D-80.00
NMS-1	Rider NMS-1 - Net Metering Service for Customer's with Generating Facilities of 20 kW or Less	D-81.00 - D-83.00
NMS-2	Rider NMS-2 - Net Metering Service for Customer's with Generating Facilities Greater than 20 kW	D-84.00 - D-87.00
ROS	Rider ROS – Resale of Service	D-88.00 - D-89.00
	APPLICABLE POWER SUPPLY AND DELIVERY CHARGE SURCHARGES AND RIDERS	
	Surcharges and Riders Cover Sheet	D-90.00
PSCR	Power Supply Cost Recovery Factor	D-91.00 – D92.00
RRS	Rate Realignment Surcharge/Credit	D-93.00
EO	Surcharge EO – Energy Optimization Surcharge	D-94.00
NDS	Nuclear Decommissioning Surcharge	D-95.00
RES	Renewable Energy Surcharge	D-96.00
NLRTS	Net Lost Revenue Tracker Surcharge	D-97.00
LIEAF	Low-Income Energy Assistance Fund Surcharge	D-98.00

(Continued on Sheet No. A-6.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

(Continued From Sheet No. A-5.00)

**SECTION E
TERMS AND CONDITIONS OF OPEN ACCESS DISTRIBUTION SERVICE**

	DESCRIPTION	SHEET NO(S).
	Terms and Conditions of Open Access Distribution Service	E-1.00 - E-21.00
	Supplier Terms and Conditions of Open Access Distribution Service	E-22.00 - E-30.00

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**STANDARD SERVICE AND OPEN ACCESS DISTRIBUTION SERVICE TARIFFS
TABLE OF CONTENTS – CHECKLIST**

SHEET NO.	EFFECTIVE DATE
Original Sheet No. A-1.00	
Original Sheet No. A-2.00	
Original Sheet No. A-3.00	
Original Sheet No. A-4.00	
Original Sheet No. A-5.00	
Original Sheet No. A-6.00	
Original Sheet No. A-7.00	
Original Sheet No. A-8.00	
Original Sheet No. A-9.00	
Original Sheet No. A-10.00	
Original Sheet No. A-11.00	
Original Sheet No. A-12.00	
Original Sheet No. A-13.00	
Original Sheet No. A-14.00	
Original Sheet No. A-15.00	
Original Sheet No. A-16.00	
Original Sheet No. A-17.00	
Original Sheet No. A-18.00	
Original Sheet No. A-19.00	
Original Sheet No. B-1.00	
Original Sheet No. B-2.00	
Original Sheet No. B-3.00	
Original Sheet No. B-4.00	
Original Sheet No. B-5.00	
Original Sheet No. B-6.00	
Original Sheet No. B-7.00	
Original Sheet No. B-8.00	
Original Sheet No. B-9.00	
Original Sheet No. B-10.00	
Original Sheet No. B-11.00	
Original Sheet No. B-12.00	
Original Sheet No. C-1.00	
Original Sheet No. C-2.00	
Original Sheet No. C-3.00	
Original Sheet No. C-4.00	
Original Sheet No. C-5.00	

(Continued on Sheet No. A-8.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

EFFECTIVE DATE: SEE ABOVE

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

(Continued from Sheet No. A-7.00)

**STANDARD SERVICE AND OPEN ACCESS DISTRIBUTION SERVICE TARIFFS
TABLE OF CONTENTS – CHECKLIST**

SHEET NO.	EFFECTIVE DATE
Original Sheet No. C-6.00	
Original Sheet No. C-7.00	
Original Sheet No. C-8.00	
Original Sheet No. C-9.00	
Original Sheet No. C-10.00	
Original Sheet No. C-11.00	
Original Sheet No. C-12.00	
Original Sheet No. C-13.00	
Original Sheet No. C-14.00	
Original Sheet No. C-15.00	
Original Sheet No. C-16.00	
Original Sheet No. C-17.00	
Original Sheet No. C-18.00	
Original Sheet No. C-19.00	
Original Sheet No. D-1.00	
Original Sheet No. D-2.00	
Original Sheet No. D-3.00	
Original Sheet No. D-4.00	
Original Sheet No. D-5.00	
Original Sheet No. D-6.00	
Original Sheet No. D-7.00	
Original Sheet No. D-8.00	
Original Sheet No. D-9.00	
Original Sheet No. D-10.00	
Original Sheet No. D-11.00	
Original Sheet No. D-12.00	
Original Sheet No. D-13.00	
Original Sheet No. D-14.00	
Original Sheet No. D-15.00	
Original Sheet No. D-16.00	
Original Sheet No. D-17.00	
Original Sheet No. D-18.00	
Original Sheet No. D-19.00	

(Continued on Sheet No. A-9.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

EFFECTIVE DATE: SEE ABOVE

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

(Continued From Sheet No. A-8.00)

**STANDARD SERVICE AND OPEN ACCESS DISTRIBUTION SERVICE TARIFFS
TABLE OF CONTENTS - CHECKLIST**

SHEET NO.	EFFECTIVE DATE
Original Sheet No. D-20.00	
Original Sheet No. D-21.00	
Original Sheet No. D-22.00	
Original Sheet No. D-23.00	
Original Sheet No. D-24.00	
Original Sheet No. D-25.00	
Original Sheet No. D-26.00	
Original Sheet No. D-27.00	
Original Sheet No. D-28.00	
Original Sheet No. D-29.00	
Original Sheet No. D-30.00	
Original Sheet No. D-31.00	
Original Sheet No. D-32.00	
Original Sheet No. D-33.00	
Original Sheet No. D-34.00	
Original Sheet No. D-35.00	
Original Sheet No. D-36.00	
Original Sheet No. D-37.00	
Original Sheet No. D-38.00	
Original Sheet No. D-39.00	
Original Sheet No. D-40.00	
Original Sheet No. D-41.00	
Original Sheet No. D-42.00	
Original Sheet No. D-43.00	
Original Sheet No. D-44.00	
Original Sheet No. D-45.00	
Original Sheet No. D-46.00	
Original Sheet No. D-47.00	
Original Sheet No. D-48.00	
Original Sheet No. D-49.00	
Original Sheet No. D-50.00	

(Continued on Sheet No. A-10.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

EFFECTIVE DATE: SEE ABOVE

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

(Continued From Sheet No. A-9.00)

**STANDARD SERVICE AND OPEN ACCESS DISTRIBUTION SERVICE TARIFFS
TABLE OF CONTENTS - CHECKLIST**

SHEET NO.	EFFECTIVE DATE
Original Sheet No. D-51.00	
Original Sheet No. D-52.00	
Original Sheet No. D-53.00	
Original Sheet No. D-54.00	
Original Sheet No. D-55.00	
Original Sheet No. D-56.00	
Original Sheet No. D-57.00	
Original Sheet No. D-58.00	
Original Sheet No. D-59.00	
Original Sheet No. D-60.00	
Original Sheet No. D-61.00	
Original Sheet No. D-62.00	
Original Sheet No. D-63.00	
Original Sheet No. D-64.00	
Original Sheet No. D-65.00	
Original Sheet No. D-66.00	
Original Sheet No. D-67.00	
Original Sheet No. D-68.00	
Original Sheet No. D-69.00	
Original Sheet No. D-70.00	
Original Sheet No. D-71.00	
Original Sheet No. D-72.00	
Original Sheet No. D-73.00	
Original Sheet No. D-74.00	
Original Sheet No. D-75.00	
Original Sheet No. D-76.00	
Original Sheet No. D-77.00	
Original Sheet No. D-78.00	
Original Sheet No. D-79.00	
Original Sheet No. D-80.00	
Original Sheet No. D-81.00	

(Continued on Sheet No. A-11.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

EFFECTIVE DATE: SEE ABOVE

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. A-11.00

(Continued From Sheet No. A-10.00)

**STANDARD SERVICE AND OPEN ACCESS DISTRIBUTION SERVICE TARIFFS
TABLE OF CONTENTS – CHECKLIST**

SHEET NO.	EFFECTIVE DATE
<u>Original Sheet No. D-82.00</u>	
<u>Original Sheet No. D-83.00</u>	
<u>Original Sheet No. D-84.00</u>	
<u>Original Sheet No. D-85.00</u>	
<u>Original Sheet No. D-86.00</u>	
<u>Original Sheet No. D-87.00</u>	
<u>Original Sheet No. D-88.00</u>	
<u>Original Sheet No. D-89.00</u>	
<u>Original Sheet No. D-90.00</u>	
<u>Original Sheet No. D-91.00</u>	
<u>Original Sheet No. D-92.00</u>	
<u>Original Sheet No. D-93.00</u>	
<u>Original Sheet No. D-94.00</u>	
<u>Original Sheet No. D-95.00</u>	
<u>Original Sheet No. D-96.00</u>	
<u>Original Sheet No. D-97.00</u>	
<u>Original Sheet No. D-98.00</u>	
<u>Original Sheet No. E-1.00</u>	
<u>Original Sheet No. E-2.00</u>	
<u>Original Sheet No. E-3.00</u>	
<u>Original Sheet No. E-4.00</u>	
<u>Original Sheet No. E-5.00</u>	
<u>Original Sheet No. E-6.00</u>	
<u>Original Sheet No. E-7.00</u>	
<u>Original Sheet No. E-8.00</u>	
<u>Original Sheet No. E-9.00</u>	
<u>Original Sheet No. E-10.00</u>	
<u>Original Sheet No. E-11.00</u>	
<u>Original Sheet No. E-12.00</u>	
<u>Original Sheet No. E-13.00</u>	
<u>Original Sheet No. E-14.00</u>	
<u>Original Sheet No. E-15.00</u>	
<u>Original Sheet No. E-16.00</u>	
<u>Original Sheet No. E-17.00</u>	

(Continued on Sheet No. A-12.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

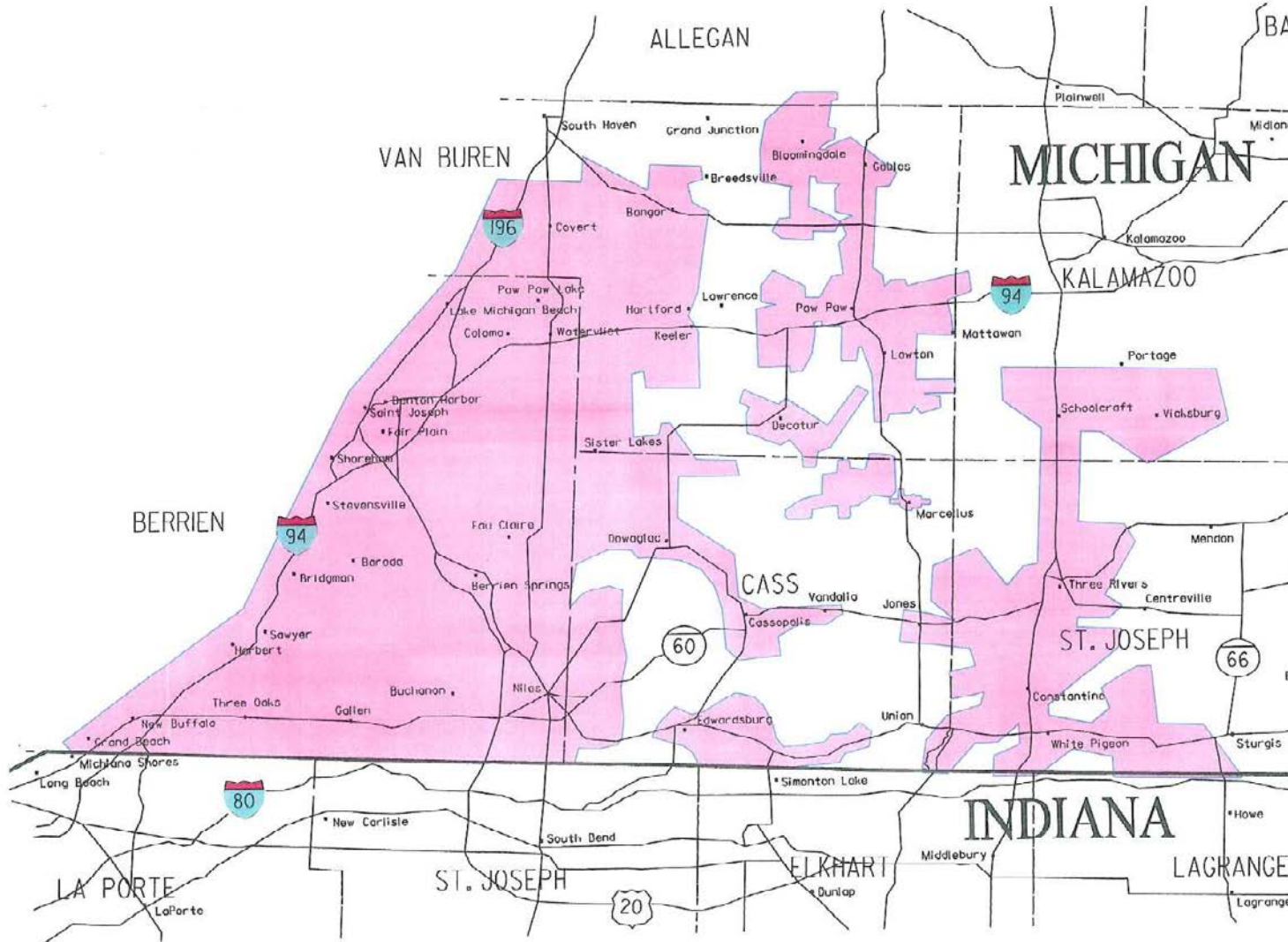
EFFECTIVE DATE: SEE ABOVE

STANDARD SERVICE AND OPEN ACCESS DISTRIBUTION TARIFFS TABLE OF CONTENTS - CHECKLIST

$$()$$

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

AREA MAP OF LOCALITIES WHERE ELECTRIC SERVICE IS AVAILABLE



**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

LOCALITIES WHERE ELECTRIC SERVICE IS AVAILABLE

Beginning November 29, 2010, all Michigan localities served by the Company became a single Rate Area served under a uniform set of Rate Schedules. The former St. Joseph and Three Rivers Rate Areas are identified below:

Former St. Joseph Rate Area

The former St. Joseph Rate Area consists of all areas served by Indiana Michigan Power Company in the State of Michigan on March 1, 1992. The following communities are located in the St. Joseph Rate Area:

Bangor, Baroda, Benton Harbor, Berrien Springs, Bridgman, Buchanan, Coloma, Eau Claire, Galien, Grand Beach, Hartford, Michiana, New Buffalo, Niles, St. Joseph, Shoreham, Stevensville, Three Oaks, and Watervliet.

The following counties/townships are located in and served by the St. Joseph Rate Area:

BERRIEN COUNTY - all Townships except Bainbridge; CASS COUNTY - all of Howard and Milton Townships and portions of Ontwa, Pokagon, Porter, and Silver Creek Townships; VAN BUREN COUNTY - all of Arlington, Bangor, Covert, Geneva, Hartford, and South Haven Townships and portions of Columbia, Hamilton, Keeler, and Lawrence Townships.

Former Three Rivers Rate Area

The former Three Rivers Rate Area consists of all areas served by Michigan Power Company in the State of Michigan on March 1, 1992. The following communities are located in the Three Rivers Rate Area:

Bloomington, Cassopolis, Constantine, Decatur, Dowagiac, Edwardsburg, Gobles, Jones, Keeler, Lawton, Marcellus, Mattawan, Paw Paw, Portage, Schoolcraft, Three Rivers, Union, Vandalia, Vicksburg, and White Pigeon.

The following counties/townships are located in and served by the Three Rivers Rate Area:

ALLEGAN COUNTY - all of Cheshire Township; BERRIEN COUNTY - only Bainbridge Township; CASS COUNTY - all of Calvin, Jefferson, LaGrange, Marcellus, Mason, Newburg, Penn, Volinia, and Wayne Townships and portions of Ontwa, Pokagon, Porter, and Silver Creek Townships; KALAMAZOO COUNTY - all of Brady, Oshtemo, Pavillion, Prairie Ronde, Schoolcraft, and Texas Townships; ST. JOSEPH COUNTY - all of Constantine, Fabius, Florence, Flowerfield, Lockport, Mottville, Park, Sherman, Sturgis, and White Pigeon Townships; VAN BUREN COUNTY - all of Almena, Antwerp, Bloomington, Paw Paw, Pine Grove, Porter, and Waverly Townships and portions of Columbia, Hamilton, Keeler, and Lawrence Townships.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER
APRIL 2012**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ABBREVIATIONS, TECHNICAL TERMS AND DEFINITIONS

ABBREVIATIONS

I&M – Indiana Michigan Power Company

kW – Kilowatt(s)

kVA – Kilovolt-ampere(s)

kWh – Kilowatt-hour(s)

MPSC - Michigan Public Service Commission

OAD - Open Access Distribution

PJM – PJM Interconnection, LLC

RKVAH – Reactive Kilovolt-ampere(s) Hour

TECHNICAL TERMS AND DEFINITIONS

“Alternative Electric Supplier or AES” – any person that is engaged in the business of supplying electric generation service to customers that take distribution service from the Company.

“Billing Cycle – Company’s schedule for meter reading and billing which distributes the starting dates for billing periods throughout the calendar month.

“Billing Demand” – Customer’s demand expressed in kW (as adjusted in accordance with the applicable rate schedule) which will be used in the calculation of the Customer’s bill.

“Billing Period or Billing Month – the interval between two consecutive meter readings that are taken for billing purposes. Such readings will be taken as nearly as practical every 30 days.

“Business Day” – any Monday through Friday when the Company’s main business office is open.

“Commission” means the Michigan Public Service Commission.

“Company” – Indiana Michigan Power Company.

“Company Standards” – Electric standards established by the Company.

“Connected load” - means the customer’s total load connected to the Company’s system.

“Contract Capacity” – Customer’s specified load requirements expressed in kW for which Customer contracts and Company is obligated to supply.

(Cont’d on Sheet No. A-16.00)

**ISSUED
BY TOBY L THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)

(Cont'd from Sheet No. A-15.00)

“Contract year or year” – twelve consecutive billing periods used in the application of rate schedules.

“Customer” – An account holder (at least 18 years old or an emancipated minor), corporation, municipality or other government agency which has agreed, orally or otherwise, to pay for electric service from the Company.

“Customer in Good Standing” – Customer that has not had service shut off involuntarily for any reason other than safety during the previous twelve months.

“Delinquent Bill” – A Customer Bill that has remained unpaid for a period of 5 or more days after the due date.

“Delivery Charges” – charges for both customer-related and distribution services including costs for Company facilities required to deliver electric energy from the transmission system to a customer's premises, including expenses for operation and maintenance of distribution facilities.

“Delivery Point” – the point at which service is delivered by Company to customer. Generally the point at which the customer's facilities are connected to the Company's facilities.

“Delivery voltage” – voltage of Company's facilities at the delivery point.

“Demand” - the quantity of electrical power required, as measured in kW or kVA and integrated over a 15-minute period, metered by a demand indicator.

“Demand Charge” - the portion of a customer's bill based on the customer's Maximum Demand, in kW and calculated on the Billing Demand under the applicable Rate Schedule.

“Disconnection” – the termination or discontinuance of electric service.

“Effective date” – means the date when the tariff sheet must be followed.

“Issue date” means the date the Company files a tariff sheet with the Commission.

“Interval Metering” – meter capable of measuring and recording energy usage and demands on a sub-hour time interval and hourly integrated basis.

“Kilovolt or kV” – a unit of electrical force, 1,000 volts.

“Kilovolt-ampere or kVA” – a unit of apparent electrical power that is the product of volts and amperes, divided by 1,000.

“Kilowatt or kW” – a unit of electrical power equal to 1,000 watts, equivalent to about 1-1/3 horsepower.

“Kilowatt-hour or kWh” – a unit of electrical energy equivalent to the quantity of electrical energy consumed by a 100 watt lamp burning ten hours.

(Cont'd on Sheet No. A-17.00)

ISSUED
BY TOBY L THOMAS
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER

ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

(Cont'd from Sheet No. A-16.00)

“Lateral Extension” – a line extension from a distribution line and is normally constructed on the customer's property to provide service to a specific premise.

“Lumen” – a unit of output of a light source.

“Metered Voltage” – the voltage at which service to the customer is measured.

“Minimum charge” – a monthly minimum charge the customer will be billed.

“Month” – unless preceded by the word “calendar,” the term “month” will refer to a billing month.

“Off-peak Period” – daily periods when the demand on the Company's generating system is usually the lowest.

“On-peak Period” – daily periods when the demand on the Company's generating system is usually the highest.

“Open Access Distribution customer” – customer receiving Open Access Distribution service from the Company.

“Open Access Distribution service or OAD” – optional service where a customer receives certain generation and transmission services from an AES.

“Other On-Site Sources of Electric Energy Supply” – shall mean customer owned, controlled or operated power production facilities located at the customer's site and designed to operate in parallel with the Company's system.

“PJM Interconnection, LLC or PJM” – is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity.

“Power Factor” – the ratio of watts to the product of volts and ampere apparent power.

“Power Supply – Capacity Charges” – are the retail power supply charges for costs incurred by Company in order to meet its customers' capacity needs.

“Power Supply – Non-Capacity Charges” – are the retail power supply charges for generation and transmission costs that are not included as Capacity Power Supply charges.

“Primary Voltage” – nominal voltages of more than 2,400 volts.

“Rate Book” means the complete set of Company filings submitted in accordance with the “Filing Procedures for Electric, Wastewater, Steam and Gas Utilities”.

(Cont'd on Sheet No. A-18.00)

**ISSUED
BY TOBY L THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-17236)**

(Cont'd from Sheet No. A-17.00)

“Rate Schedule” or “Rider” means the rate or charge for a particular classification of service, including all special terms and conditions under which that service is furnished at the prescribed rate or charge.

“Reactive Kilovolt Ampere Hours or RKVAH” - a unit of power that is also known as "imaginary" or "reactive" power equal to 1,000 volt-ampere of reactive power (kVAR) measured or consumed over one hour.

“Regular Business Hours” – hours of operation designated by the Company occurring on Business Days.

“Residential Customer” – a customer receiving service for a dwelling unit, defined as one or more rooms including kitchen in a facility designed as living accommodations for occupancy by one family for the purpose of cooking, living and sleeping.

“Rules or Regulations” means the rules, regulations, practices, classifications, exceptions, and conditions that the Company must observe when providing service.

“Secondary Voltage” – nominal voltages of less than 480 volts.

“Service” – the supply of electric energy delivered by Company to the Customer.

“Service Facilities” – are those facilities between the Company's last electric plant unit and the point of termination. For service through a meter operating at 600 volts or less where facilities are overhead, this is generally the weatherhead; where facilities are underground; this is generally the meter socket. For those Primary Service customers who desire to take service directly from the electric distribution system, generally the last Company electric plant unit would be the meter installation and there would not be any Service Facilities involved since the customer usually owns all facilities beyond the meter.

“Standard service” – service where customer is receiving generation, transmission and distribution services from the Company under a Commission approved rate schedule.

“Standard service customer” – customer receiving Standard service from the Company.

“Subtransmission Voltage” – nominal voltages of 34,500 volts to 69,000 volts.

“Tariff” – the entire body of rate schedules, riders, general terms and conditions for electric service.

“Transmission Voltage” – nominal voltages of 138,000 volts to 765,000 volts.

“Underground” – those parts of Company's distribution system which are constructed and direct buried underground.

“Volt” – a unit of electrical force.

“Watt” – the electrical unit of power or rate of doing work.

“Year” – unless preceded by the word “calendar,” the term “year” will refer to twelve consecutive billing months.

**ISSUED
BY TOBY L THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

COMPANY TERMS AND CONDITIONS OF STANDARD SERVICE

1. APPLICATION

These Terms and Conditions of Standard Service apply to service under the Company's tariffs that provide for Power Supply (generation and transmission), and Delivery (distribution) service. Customers requesting only distribution service from the Company, irrespective of the voltage level at which service is taken, as provided for in the Customer Choice and Electricity Reliability Act, shall be served under the Company's tariffs and the Terms and Conditions of Open Access Distribution Service.

Standard Service furnished by the Company is subject to the terms and conditions of the applicable tariffs and Terms and Conditions of Standard Service which are at all times subject to revision, change, modification, or cancellation by the Company, subject to the approval of the Michigan Public Service Commission, and which are, by reference, made a part of all standard contracts (both oral and written) for Standard Service. Failure of the Company to enforce any of the terms of these tariffs and Terms and Conditions of Standard Service shall not be deemed a waiver of its right to do so.

A copy of all tariffs and Terms and Conditions of Standard Service is on file with the Michigan Public Service Commission and may be inspected by the public in any of the Company's business offices. Upon request, the Company will supply, free of charge, a copy of the rate schedules applicable to service available to existing customers or new applicants for service. When more than one rate schedule is available for the service requested, the customer shall designate the rate schedule on which the application or contract shall be based. Where applicable the customer may change from one rate schedule to another once at the end of each full 12-month period or as specified by tariff or contract, upon written application to the Company. In no case will the Company refund any difference in charges between the rate schedule under which service was supplied in prior periods and the newly selected rate schedule.

A written agreement may be required from each customer before service will be commenced. A copy of the agreement will be furnished to the customer upon request.

By receiving service under a specific tariff, the customer has agreed to all terms and conditions of that tariff. A customer's refusal or inability to sign a contract or agreement as specified by the tariff, in no way relinquishes the customer's obligations as specified in the tariff.

When the customer desires delivery of energy at more than one point, a separate agreement will be required for each separate point of delivery. Service delivered at each point of delivery will be billed separately under the applicable tariff. Conjunctive billing and/or aggregate demands are prohibited. Under certain circumstances the Company may have provided two services to fulfill the customer's lighting and power requirements at a single location and the metering for the two services have been combined for billing. Existing such arrangements are explicitly grandfathered until an account change occurs. Once an account change occurs, combined billing of grandfathered multiple meters

(Continued on Sheet No. C-2.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. C-1.00)

would end. Each point of delivery would then require a separate agreement for each separate point of delivery. For new service/accounts, multiple metering is permitted only for Company convenience

2. BILLS FOR STANDARD ELECTRIC SERVICE

A. General

Bills for electric service will be rendered monthly at intervals of approximately 30 days in accordance with the tariff selected applicable to the customer's service. All bills are rendered as "net" bills and are subject to a late payment charge if the account is delinquent. Late payment charges will be assessed on Residential bills in accordance with Rule 460.122 and on Commercial and Industrial bills in accordance with Rule 460.1614. A late payment charge shall not be assessed against any residential customers who are participating in the winter protection plan as described in Rule 460.148 and Rule 460.149 of the Consumer Standards and Billing Practices for Residential Customers. Any governmental agency shall be allowed such additional period of time for payment of the net bill as the agency's normal fiscal operations require, not to exceed 30 days.

It may be necessary for the Company to render a bill on an estimated basis if extreme weather conditions, emergencies, work stoppage, or other circumstances of force majeure prevent actual meter readings. Pursuant to Rule 460.113, any bill rendered on an estimated basis shall be clearly and conspicuously identified. In the event of the stoppage of or the failure of any meter to register an accurate amount of energy consumed, as described in Rule 460.116, the customer will be charged or credited for such period on an estimated consumption based upon energy use during a similar period of like use. Meter errors shall be reconciled in accordance with Rule 460.3309. This estimation shall include adjustments for changes in customer's load during the period the meter was not registering properly. As stated in Rule 460.116 (2), any meter in service that remains broken as determined by a specific test of the meter or that does not correctly register customer usage for a period of 6 months or more shall be removed and customers will not be required to pay bills generated from these meter readings beyond the 6-month period from the date the meter malfunction occurred. This rule does not alter the provisions of Rule 460.3613 governing the testing and replacement of electric meters.

A bill shall be mailed, transmitted, or delivered to the customer not less than 21 days before the due date. Failure to receive a bill properly mailed, transmitted, or delivered by Company does not extend the due date. Upon request the Company will advise the customer of the approximate date on which the bill will be mailed each month, and if the bill is lost, the Company will issue a duplicate.

B. Non-residential

Billing errors for non-residential accounts shall be rectified as described in Rule 460.1617. If a customer has been overcharged, the utility shall refund or credit the amount of the paid overcharge to the customer. Overcharges shall be credited to customers with 7% interest,

(Continued on Sheet No. C-3.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. C-2.00)

commencing on the 60th day following payment. The Company is not required to adjust, refund, or credit an overcharge beyond the 3-year period immediately preceding discovery of the billing error, unless the customer is able to present a record establishing an earlier date of occurrence or commencement of the error.

In cases of unauthorized use of utility service the customer may be back billed for the amount of the undercharge. The back bill may include interest at the same 7% interest rate applied to overcharges.

In cases not involving unauthorized use of utility service, the customer may be back billed for the amount of the undercharge during the 12-month period immediately preceding discovery of the error. The Company shall offer the customer at least the same number of months for repayment equal to the time of the error. The back bill shall not include interest.

C. Residential

Billing errors for residential accounts shall be rectified as described in Rule 460.126. If a customer has been overcharged due to a billing error, the Company shall refund or credit the amount of the paid overcharge plus 7% APR interest on the bill immediately following the discovery of the error. Upon customer request, overcharges greater than \$10 shall be refunded within 30 days. The Company is not required to adjust, refund, or credit an overcharge plus 7% APR interest for more than the 3 years immediately preceding discovery of the billing error, unless the customer is able to establish an earlier date for commencement of the error. The interest on the overcharge shall be applied on the 60th day following the paid overcharge.

If the Company undercharges a customer, the following provisions apply:

In cases that involve unauthorized use of utility service the utility may back bill the customer for the amount of the undercharge using the commission-approved process for estimating the bill. The utility may charge fees for unauthorized use of utility service in accordance with commission-approved tariffs.

In cases that do not involve unauthorized use of utility service, the utility may back bill the customer for the amount of the undercharge during the 12-month period immediately preceding discovery of the error, and the utility shall offer the customer reasonable payment arrangements for the amount of the back bill, which shall allow the customer to make installment payments over a period at least as long as the period of the undercharge. The utility shall take into account the customer's financial circumstances when setting payment amounts.

D. Budget Bill Payment Options

In addition to paying the actual monthly bill amount, Residential customers using electric service with a satisfactory payment history shall have the option of paying bills under one of the Company's two budget billing plans – the Equal Payment Plan (EPP) or the Average Monthly Payment Plan (AMPP), both of which are described below.

(Continued on Sheet No. C-4.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. C-3.00)

Under the Equal Payment Plan (EPP), the total service for the succeeding 12-month period is estimated in advance and bills are rendered monthly on the basis of one-twelfth of the 12-month estimate. The Company may at any time during the 12-month period adjust the estimate so made, and the bills rendered in accordance with such estimate, to conform more nearly with the actual use of service being experienced.

In case the actual service used during any equal payment period exceeds the bills as rendered on the EPP, the amount of such excess shall be paid on or before the due date of the bill covering the last month of the equal payment period in which such excess appears. Such excess may be added to the estimated use for the next normal equal payment period of 12 months and shall be payable in equal monthly payments over such period, except that if the customer discontinues service with the Company under the EPP, any such excess not yet paid shall become payable immediately. In case the actual service used during the equal payment period is less than the amount paid under the EPP during such period, as specified in R460.118, if a customer has a credit balance of more than \$10.00 at the end of the period, upon the request of the customer, the utility shall either return the credit balance or credit it to the next month's bill. If the balance is less than \$10.00, the utility shall credit the amount to the customer's account.

If a customer fails to pay bills as rendered on the EPP, the Company shall have the right to withdraw the EPP with respect to such customer and restore the customer to billing as provided for in the applicable tariffs, in addition to any other rights which the Company may have under such tariffs in case of arrearage in payment of bills. If a customer requests removal from the EPP, the amount of any excess payments made under the EPP will be applied as a credit on the next month's bill. Likewise, if there is a deficiency in payments, the amount of deficiency will be added to next month's bill.

Under the Average Monthly Payment Plan (AMPP), variations in customer billings are minimized by allowing the customer to pay an average amount each month based on the current month's billing plus the eleven (11) preceding months, divided by the total billing days associated with those billings to get a per day average. The average daily amount will be multiplied by thirty (30) days to determine the current month's payment under the AMPP. At the next billing period, the oldest month's billing history is dropped, the current month's billing is added and the average is recalculated to find a new payment amount. The average is recalculated each month in this manner.

In such cases where sufficient billing history is not available, an AMPP account may be established allowing the first month's amount due to be the average based on the actual billing for the month. The second month's amount due will be the average based on the first and second billing. The average will be recomputed each month using the available actual history throughout the first AMPP year.

Actual billing will continue to be based on the applicable rate and meter readings obtained to determine consumption. The difference between actual billings and the averaged billings under the AMPP will be carried in a deferred balance that will accumulate both debit and credit differences for the duration of the AMPP year – twelve (12) consecutive months. At the end of the AMPP year (anniversary month), the net accumulated deferred balance is divided by twelve (12) and the result is included in the average payment amount starting with the first billing of the new

(Continued on Sheet No. C-5.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. C-4.00)

AMPP year and continuing for twelve (12) consecutive months. Settlement occurs only when participation in the plan ends.

If a customer fails to pay bills as rendered on the AMPP, the Company shall have the right to withdraw the AMPP with respect to such customer and restore the customer to billing as provided for in the applicable tariffs, in addition to any other rights the Company may have under such tariffs in case of arrearage in payment of bills. If a customer requests removal from the AMPP, the amount of any overpayment made under the AMPP will be applied as a credit on the next month's bill. Likewise, any amount of under payment will be applied as a charge to the next month's bill.

3. INSPECTION

It is to the interest of the customer to properly install and maintain customer-owned wiring and electrical equipment, and the customer shall at all times be responsible for the character and condition thereof. The Company makes no inspection thereof and in no event shall be responsible therefore.

Where a customer's premises are located in a municipality or other governmental subdivision where inspection laws or ordinances are in effect, the Company may withhold furnishing service to new installations or disconnected existing installations until it has received evidence that the inspection laws or ordinances have been complied with. In addition, if such municipality or other governmental subdivision shall determine that such inspection laws or ordinances are no longer being complied with in respect to an existing installation, the Company may suspend the furnishing of service thereto until it has received evidence of compliance with such laws or ordinances.

Before furnishing service, Company shall require a certificate or notice of approval from a duly recognized authority stating that customer's wiring has been installed in accordance with local and state requirements.

No responsibility shall attach to the Company because of any waiver of these requirements.

4. SERVICE CONNECTIONS

The Company will, when requested to furnish service, designate the location of its service connection. The customer's wiring must, except for those cases listed below, be brought outside the building wall nearest the Company's service wires so as to be readily accessible thereto. When service is from an overhead system, the customer's wiring must extend a distance beyond the building as established by local codes and Company standards. Where customers install service entrance facilities as specified by the Company and/or install and use certain utilization equipment as specified by the Company, the Company may provide or offer to own certain facilities beyond the point where the Company's service wires attach to the building.

The Company reserves the right to make final determination of selection, application, location, routing and design of its service facilities and meter location. If the customer requests special routing of the service facilities and or meter location, the customer will be required to pay the extra cost, if any, resulting from the special routing of service facilities and or meter location.

All customers' wiring must be grounded in accordance with the requirements of the National Electrical Code or the requirements of any local inspection service authorized by a state or local authority.

(Continued on Sheet No. C-6.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. C-5.00)

When a customer desires that energy be delivered at a point or in a manner other than that designated by the Company, the customer shall pay the additional cost of same, including any and all required engineering studies.

When a customer requests additional engineering studies beyond the normal overhead and/or underground options providing an adequate plan of service, as designated by the Company, for a new or relocated service, the Company shall charge the customer, payable in advance, for actual cost incurred by the Company to conduct such studies. Normal engineering studies include any obvious options such as overhead and underground installations.

Where service is supplied from an underground distribution system which has been installed at the Company's expense, the customer shall make arrangements with the Company for the Company to supply and install a continuous run of cable conductors including necessary ducts from the manhole or connection box to the meter location where it is necessary that the location of the meter be inside the customer's building. The customer shall reimburse Company for the cost of the portion of cable and duct from the property line to the terminus of cable inside the building.

5. LOCATION AND MAINTENANCE OF COMPANY'S EQUIPMENT

The Company shall have the rights to construct its poles, lines, and circuits on the property, and to place its transformers and other apparatus on the property or within the buildings of the customer, at a point or points convenient for the purpose, as required to serve the customer. The customer shall keep company equipment clear from obstruction and obstacles including landscaping, structures, etc., and provide suitable space for the installation, repair and maintenance of necessary measuring instruments so that the instruments may be protected from injury by the elements or through negligence or deliberate acts of the customer or any other person who is not an agent or employee of the Company.

When Company facilities are damaged due to customer actions or negligence, the Customer shall be responsible for the costs of repairs.

6. RELOCATION OF COMPANY'S FACILITIES AT CUSTOMER'S REQUEST

Whenever, at customer's request, the Company's facilities are relocated solely to suit the convenience of customer, the customer shall reimburse the Company for the entire cost incurred in making such change including any and all required engineering studies.

7. COMPANY'S LIABILITY

The Company will use reasonable diligence in furnishing a regular and uninterrupted supply of energy, but does not guarantee uninterrupted service. The Company shall not be liable for damages in case such supply should be interrupted or fail by reason of an act of God, the public enemy, accidents, labor disputes, or orders or acts of civil authority. Further, the Company shall not be liable for damages in case such supply should be interrupted due to causes or conditions beyond the Company's reasonable control, including extraordinary repairs, breakdowns or injury to machinery, transmission lines, distribution lines, or other facilities of the Company. Further, the Company shall not be liable for damages for interrupting service to any customer, whenever in the judgment of the Company such interruption is necessary in order to prevent or limit any instability or disturbance on the electric system of

(Continued on Sheet No. C-7.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. C-6.00)

the Company or any electric system interconnected with the Company, such interruptive action to be taken in accordance with predetermined plan and only in situations that threaten massive curtailments of service on the Company's system.

Unless otherwise provided in a contract between Company and customer, the point at which service is delivered by Company to customer, to be known as "delivery point," shall be the point at which the customer's facilities are connected to the Company's facilities. The metering device is the property of the Company; however, the meter base and all internal parts inside the meter base are customer owned and are the responsibility of the customer to install and maintain. The Company shall not be liable for any loss, injury, or damage resulting from the customer's use of customer-owned equipment or occasioned by the energy furnished by the Company beyond the delivery point.

The customer shall provide and maintain suitable protective devices on the customer's equipment to prevent any loss, injury, or damage that might result from single-phasing conditions or any other fluctuation or irregularity in the supply of energy. The Company shall not be liable for any loss, injury, or damage resulting from a single-phasing condition or any other fluctuation or irregularity in the supply of energy that could have been prevented by the use of such protective devices. . The Company shall not be liable for any damages, whether direct or consequential, including, without limitations, loss of profits, loss of revenue, or loss of production capacity occasioned by interruptions, fluctuations or irregularity in the supply of energy.

The Company is not responsible for loss or damage to customer's property caused by the disconnection or reconnection of service to the customer's facilities. The Company is not responsible for loss or damages to customer's property caused by the theft or destruction of Company facilities by a third party.

The Company will provide and maintain the necessary line or service connections, transformers (when the same are required by conditions of contract between the parties thereto), meters, and other apparatus that may be required for the proper measurement of and protection to its service. All such apparatus shall be and remain the property of the Company.

8. CUSTOMER'S LIABILITY

In the event of loss or injury to the property of the Company through misuse by, or the negligence of, the customer or the employees of the same, the cost of the necessary repairs or replacement thereof shall be paid to the Company by the customer.

The customer shall be responsible and, therefore, shall insure that no one except Company employees or agents of the Company shall make any internal or external adjustments to, or otherwise interfere with, or break the seals of meters or other Company-owned equipment installed on customer's property.

The Company shall have the right to enter, at all reasonable hours, the premises of the customer for the purpose of installing, reading, removing, testing, replacing, or otherwise disposing of its apparatus and property, and the right of entire removal of the Company's property in the event of termination of service for any cause. The customer must keep the immediate area and access area in and around the Company's equipment clean and free of debris.

(Continued on Sheet No. C-8.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. C-7.00)

9. USE OF ENERGY BY CUSTOMER

The tariffs for electric energy given herein are classified by the character of use of such energy and are not available for service other than as provided herein. Service will not be furnished under any tariff of the Company on file with the Commission to any customer, applicant, or group of applicants desiring service with the intent or for the purpose of reselling any or all of such service. For purposes of this tariff, the provision of electric vehicle charging service for which there is no direct per kWh charge shall not be considered resale of service. It shall be understood that upon the expiration of a contract the customer may elect to renew the contract upon the same or another tariff published by the Company available in the locality in which the customer resides or operates and applicable to the customer's requirements. In no case shall the Company be required to maintain transmission, switching, or transformation equipment (either for voltage or form of current change) different from, or in addition to, that generally furnished to other customers receiving electrical supply under the terms of the tariff elected by the customer.

A customer may not change from one tariff to another during the term of contract except with the consent of the Company or within a reasonable period after a Commission-approved change in tariffs.

The service connections, transformers, meters, and appliances supplied by the Company for each customer have a definite capacity and no additions to the equipment, or load connected thereto, will be allowed except by consent of the Company.

The customer shall install only motors, apparatus, or appliances which are suitable for operation with the character of the service supplied by the Company, which shall not be detrimental to same, and the electric power must not be used in such a manner as to cause unprovided-for voltage fluctuations or disturbances in the Company's transmission or distribution system. The Company shall be the sole judge as to the suitability of apparatus or appliances, and also as to whether the operation of such apparatus or appliances is, or will be, detrimental to its general service.

The customer is responsible to provide any timing equipment and timing control signals to operate time differentiated load.

No attachment of any kind whatsoever may be made to the Company's lines, poles, crossarms, structures, or other facilities without the express written consent of the Company.

All apparatus used by the customer shall be of such type as to secure the highest practicable commercial efficiency, power factor, and the proper balancing of phases. Motors which are frequently started or arranged for automatic control must be of a type to give maximum starting torque with minimum current flow and of a type equipped with controlling devices approved by the Company. The customer agrees to notify the Company of any increase or decrease in the customer's connected load.

The operation of certain electrical equipment can result in disturbances (e.g., voltage fluctuations, harmonics, etc.) on the Company's transmission and distribution systems that can adversely impact the operation of equipment for other customers. Customers are expected to abide by industry standards, such as those contained in ANSI/IEEE 519 or the IEEE/GE voltage flicker criteria, when operating such equipment. The Company may refuse or disconnect service to customers for using

(Continued on Sheet No. C-9.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. C-8.00)

electricity or equipment that adversely affects distribution service to other customers. Copies of the applicable criteria will be provided upon request.

The Company will not supply service to customers who have other on-site sources of electric energy supply except under the tariffs that specifically provide for same.

The customer shall not be permitted to operate the customer's own generating equipment in parallel with the Company's service except on written permission of the Company or under specifically approved tariffs.

The Company may provide service to and take service from certain qualifying facilities defined as cogeneration or small power production facilities. Such sales and purchases are subject to contract and Commission authorization.

10. RESIDENTIAL SERVICE

Individual residences shall be served individually with single-phase service under the appropriate residential tariff. Customer may not take service for three or more separate living units through a single point of delivery under any tariff, irrespective of common ownership of the several residences, except that in the case of an existing apartment house with a number of individual apartments, the landlord shall have the choice of providing separate wiring for each apartment so that the Company may supply each apartment separately under the residential tariff, or of purchasing the entire service through a single meter under the appropriate general service tariff without submetering the service to the apartments. This central metering provision shall not be permitted for new customers.

In a two-family dwelling the owner may, at the owner's option, take service through a single meter under the residential tariff instead of providing separate wiring for both dwelling units. When service is taken through a single meter, the two-family dwelling will be billed as a single-family residence.

The residential tariff shall cease to apply to that portion of a residence which becomes regularly used for business, professional, institutional, or other gainful purposes or which requires three-phase service. Single-phase motors of 10 HP or less may be served under the appropriate residential tariff. Larger single-phase motors may be served where, in the Company's sole judgment, the existing facilities of the Company are adequate.

Under these circumstances, customer shall have the choice of: (1) separating the wiring so that the residential portion of the premises is served through a separate meter under the residential tariff and the other uses as enumerated above are served through a separate meter or meters under the appropriate general service tariff, or (2) taking the entire service under the appropriate general service tariff.

Detached building or buildings actually appurtenant to the residence, such as a garage, stable, or barn, may be served by an extension of the customer's residence wiring through the residence meter.

(Continued on Sheet No. C-10.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. C-9.00)

11. RESORT SERVICE

Where customers desire electric service for summer homes, summer resort hotels, or other summer resort establishments which are located adjacent to existing distribution lines of the Company and can be served without the extension of primary lines, they shall have the privilege of purchasing all-year service under the applicable all-year tariffs or of purchasing service for less than a full year under the applicable residential or general service tariffs, subject to payment in advance of an amount commensurate with the cost of handling the customer's account, for connection to and disconnection from the Company's lines.

12. EXTENSION OF SERVICE

A. Residential Service

i. Charges

For each permanent, year-round dwelling, the Company will provide a single-phase line extension excluding service drop at no additional charge for a distance of 200 feet. Distribution line extension in excess of the above footage will require an advance deposit of \$3.50 per foot for all such excess footage. There will also be a nonrefundable contribution equal to the cost of right-of-way and clearing on such excess footage. Three-phase extensions, as required to service large developments, will be on the same basis as Commercial and Industrial.

ii. Measurement

The length of any main line distribution feeder extension will be measured along the route of the extension from the Company's nearest facilities from which the extension can be made to the customer's property line. The length of any lateral extension on the customer's property shall be measured from the customer's property line to the service pole. Should the Company for its own reasons choose a longer route; the applicant will not be charged for the additional distance; however, if the customer requests special routing of the line, the customer will be required to pay the extra cost resulting from the special routing.

iii. Refunds

During the five-year period immediately following the date of payment, the Company will make refunds of the charges paid for a financed extension under provisions of paragraph (i) above. The amount of any such refund shall be \$165 for each permanent electric service subsequently connected directly to the facilities financed by the customer. Directly connected include any amount of contribution in aid of construction for underground service made under customers are those that do not require the construction of more than 100 feet of lateral primary distribution line. Such refunds will be made only to the original depositor and will not

(Continued on Sheet No. C-11.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. C-10.00)

include any amount of contribution in aid of construction for underground service made under the provisions of the Company's underground service policy as set forth in this section. The total refund shall not exceed the refundable portion of the contribution.

B. Commercial or Industrial Service

i. Company Financed Extensions

Except for contributions in aid of construction for underground service made under the provisions of Item 13, C of these rules, the Company will finance the construction cost necessary to extend its facilities to serve commercial or industrial customers when such investment does not exceed two times the annual capacity power supply and delivery charge revenue anticipated to be collected from customers initially served by the extension.

ii. Charges

When the estimated cost of construction of such facilities exceeds the Company's maximum initial investment as defined in paragraph (i), the applicant shall be required to make a deposit in the entire amount of such excess construction costs. Owners or developers of mobile home parks shall be required to deposit the entire amount of the estimated cost of construction, subject to the refund provisions of paragraph (iii).

iii. Refunds

That portion of the deposit related to the difference in the cost of underground construction and the equivalent overhead facilities shall be considered nonrefundable. This amount shall be determined under the applicable provisions of the Company's underground service policy as set forth in this section.

The Company will make refunds on remaining amounts of deposits collected under the provisions of paragraph (ii) above in cases where actual experience shows that the capacity power supply and delivery charge revenues supplied by the customer are sufficient to warrant a greater initial investment by the Company. Such refunds shall be computed as follows:

(1) Original Customer

At the end of the first complete 12-month period immediately following the date of initial service, the Company will compute a revised revenue credit based on two times the actual capacity power supply and delivery charge revenue provided by the original customer in the 12-month period. Any amount by which twice the actual annual capacity power supply and delivery charge revenue exceeds the Company's initial revenue estimate will be made available for refund to the customer; no such refund shall exceed the amount deposited under provisions of paragraph (ii) above.

(Continued on Sheet No. C-12.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. C-11.00)

- (2) Refunds for additional new customers directly connected to the financed extension during the refund period will be governed by Section 12, A, iii.

iv. Loads of Uncertain Duration

When, in the opinion of the Company, the permanence and continuance of the customer's load is questionable, the Company may require the applicant to make an advance deposit for line construction or service to cover the Company's costs of extending its electric lines and furnishing and installing necessary transformation, metering and protective equipment to supply electricity to the customer's premises. The advance deposit with the Company will be made up of two components (1) the estimated cost of constructing the facilities to serve the customer, including labor, material, stores freight and handling expenses, and a charge for overhead, plus (2) the estimated cost of removing said facilities and returning the materials to the Company storeroom, minus the estimated value of salvaged materials to be returned to storeroom at the end of the electrical service.

Any customer making an advance deposit under this section is eligible for a rebate of the monies advanced under (1) of the preceding paragraph, beginning with the first full billing month for full operation of the customer's facility and ending with the 24th consecutive month thereafter. The rebate will be 40% of the monthly electric service paid by the customer. The total amount of all rebates shall not exceed the amount of the monies advanced under (1) of the preceding paragraph. In addition, following the continuous use of electric service for twenty-four (24) months, any monies held by the Company will be promptly refunded to the customer. The Company, at its discretion, may accept a letter of credit or performance bond, payable to the Company, in lieu of an advance deposit.

C. General

The Company will extend its lines to serve domestic customers and farm customers for year-round service under applicable tariffs subject to the following conditions:

- i. Extensions hereunder shall be built by the Company in accordance with its construction standards and shall be single phase unless the Company elects to build polyphase lines.
- ii. In those cases where it is not feasible or practicable to construct lines on public rights-of-way and it is necessary to secure rights-of-way on private property or tree trimming permits, the applicant or applicants shall secure the same without cost to the Company, or assist the Company, in obtaining such rights-of-way on private property or tree trimming permits before construction

(Continued on Sheet No. C-13.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. C-12.00)

shall commence. The Company shall be under no obligation to construct lines in event the necessary rights-of-way or tree-trimming permits cannot be so obtained.

13. UNDERGROUND ELECTRIC LINES

A. General

In case of all direct burial underground extensions of electric distribution facilities as covered by conditions as set forth in this Section 13, the real estate developer or customer shall make a nonrefundable contribution in aid of construction to the Company in an amount equal to the estimated difference in cost between overhead and direct burial underground facilities. "Distribution facilities" means those operated at 20,000 volts or less to ground for wye connected systems and 20,000 volts or less for delta connected systems. Charges in this Section 13 are in addition to any charges that may be required in Section 12 for equivalent overhead facilities.

B. Residential

i. In Subdivisions

(1) Distribution Facilities

The distribution system in a new residential subdivision and an existing residential subdivision in which electric distribution facilities have not already been constructed shall be placed underground, except that a lot facing a previously existing street or county road and having an existing overhead distribution line on its side of the street or county road shall be served with an underground service from these facilities and shall be considered a part of the underground service area.

The owner or developer of such shall be required to make a nonrefundable contribution in aid of construction to the Company, for direct burial underground distribution facilities, in an amount equal to the sum of the lot front-foot measurement multiplied by \$ 4.50, which amount shall be considered to be the difference in cost between overhead and direct burial underground distribution facilities.

The front-foot measurement of each lot to be served by a residential underground distribution system shall be made along the contour of the front lot line. The front lot line is that line which usually borders on or is adjacent to a street.

However, when streets border on more than one side of a lot, the shortest dimension shall be used. In case of a curved lot line that borders on a street or streets and represents at least two sides of the lot, the front-foot measurements shall be considered as one-half the total measurement of the curved lot line. Where a lot is served by an underground service

(Continued on Sheet No. C-14.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. C-13.00)

from an overhead distribution line, the lot front-foot measurement shall be deleted. The construction provided for in the \$ 4.50 per lot front-foot contribution in aid of construction includes the extension of electric underground distribution facilities to the lot line of each lot in the subdivision.

The use of the lot front-foot measurement in these rules shall not be construed to require that the underground electric distribution facilities be placed on the front of the lot.

(2) Service Facilities

The Company shall install, own, and maintain the service line from the property line to the customer's meter. For normal installation of the service line, the developer or customer shall make a nonrefundable contribution in aid of construction to the Company in an amount equal to \$6.00 per trench foot.

ii. Outside of Subdivisions

(1) Distribution Facilities

The customer located outside of subdivisions shall be required to make a nonrefundable contribution in aid of construction to the Company in an amount equal to the estimated total difference in cost between overhead and underground construction costs.

(2) Service Facilities

For normal installation of the service line, the customer shall make a nonrefundable contribution in aid of construction to the Company in an amount equal to \$6.00 per trench foot.

iii. Mobile Home Parks, Condominiums and Apartment House Complexes

The distribution and service facilities for new and existing mobile home parks, condominiums, and apartment house complexes in which electric facilities have not already been constructed shall be placed underground.

The owner or developer of such mobile home parks, condominiums, and apartment house complexes shall be required to make a nonrefundable contribution in aid of construction to the Company for distribution facilities in an amount equal to \$4.50 per trench foot and service facilities in an amount equal to \$12.25 per trench foot and \$11.25 per kVA for transformers (installed). Owners or developers of mobile home parks shall be required to deposit the entire amount of the estimated cost of construction, subject to the refund provisions of Section 12 B (iii).

(Continued on Sheet No. C-15.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. C-14.00)

C. Commercial and Industrial

Commercial distribution and service lines in the vicinity of the customer's property and constructed solely to serve a customer or group of adjacent customers shall be placed underground. This will specifically include, but not be limited to, service to shopping centers.

Industrial distribution and service lines shall be placed underground at the option of the customer.

The developer or customer shall be required to make a nonrefundable contribution in aid of construction to the Company for the following facilities which amount shall be considered to be the difference in cost between overhead and direct burial underground facilities:

- | | | |
|------|---|--|
| i. | Distribution facilities - | Single-phase - \$4.50 per trench foot.
Three-phase - \$3.00 per trench foot. |
| ii. | Transformers - | Single-phase - \$8.00 per kVA (installed).
Three-phase - \$12.50 per kVA (installed). |
| iii. | Service, as this term is generally understood in the electric utility field, (on customer's property) - | Single-phase - \$8.00 per trench foot.
Three-phase - \$12.50 per trench foot. |

D. Special Conditions

Where practical difficulties exist, such as water conditions, rock near the surface, or where there are requirements for deviation from the Company's construction standards such as directional boring, the per foot charges in B and C will not apply, and the contribution in aid of construction will be equal to the estimated difference in cost between overhead and underground facilities but not less than the charge calculated under B and C.

An additional amount of \$1 per foot shall be added to the trenching charges for the practical difficulties associated with winter construction in the period from December 15 to March 31, inclusive. This charge will not apply to jobs that are ready for construction and for which the construction meeting has been held prior to November 1.

E. Replacement of Existing Overhead Electric Facilities

Existing overhead residential, commercial, and industrial electric distribution and service lines shall be replaced with underground facilities at the option of the affected customer or customers. Before construction is started, the customer shall be required to pay the Company the depreciated cost (net cost) of the existing overhead facilities plus the cost of removal less the salvage value thereof and, also, make a nonrefundable contribution in aid of construction in an amount equal to the estimated difference in cost between new underground and new overhead facilities including, but not limited to, the costs of breaking and repairing streets, walks, parking lots, and driveways, repairing lawns, and replacing grass, shrubs, and flowers.

(Continued on Sheet No. C-16.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. C-15.00)

14. TEMPORARY SERVICE.

Temporary service is electric service that is required during the construction phase of a project and/or electric service that is provided to new customers for a period not to exceed 12 months except in cases of large construction projects and the customer has notified the Company of the need to extend this timeframe. Such service is available only upon approval of the Company. In order to qualify for temporary service, the customer must demonstrate to the Company's satisfaction that the requested service will, in fact, be temporary in nature.

Temporary service for residential construction will be supplied using Tariff R.S. Temporary service for general service construction will be supplied under the appropriate published general service tariff applicable to the class of business of the customer. Temporary service will be supplied when the Company has available unsold capacity of lines, transformers, and generating equipment. The customer will be charged a minimum temporary service installation charge, payable in advance, based on the Company's actual cost to install and remove, less salvage, the required facilities to provide the temporary service. In no case shall revenue credits apply to cover costs associated with temporary service. The Company reserves the right to require a written contract for temporary service, at its option.

15 DENIAL OR DISCONTINUANCE OF SERVICE

Pursuant to Rules 460.136, 460.137, and 460.1625, the Company reserves the right to shutoff service to any customer without notice, in case of an emergency or to prevent fraud upon the Company. Additional shutoff of service rules applicable to nonresidential service are set forth in the MPSC Rules in Part 7 of the Billing Practices Applicable to Non-Residential Electric and Gas Customers, as referenced herein, and are set forth, as applicable, to residential service in Part 8 of the Consumer Standards and Billing Practices for Electric and Gas Residential Service, as referenced herein.

Any shutoff of service shall not terminate the contract between the Company and the customer nor shall it abrogate any minimum charge that may be effective.

The Company may disconnect service without request by the customer and with proper notification in writing of at least 14 days when:

- (a) The customer does not provide adequate access to the meter during normal business hours or denies access to other Company equipment; or
- (b) The customer does not provide adequate safe clearance in front of and around metering and associated equipment; or
- (c) The customer does not allow safe egress and regress across the customer's property to access metering and other Company equipment; or
- (d) The meter is located in an inaccessible location such as a basement, fenced area, porch, etc., and the customer denies the Company reasonable access; or
- (e) The customer's equipment falls into disrepair due to aging or abuse and needs to be replaced due to eminent safety considerations; or
- (f) The meter installation does not fall under commonly acceptable installation practices or where conditions at the customer's site change, causing the meter installation to no longer meet acceptable installation guidelines.

(Continued on Sheet No. C-17.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. C-16.00)

The Company may disconnect service without request by the customer and without prior notice only:

- (a) If a condition dangerous or hazardous to life, physical safety, or property exists; or
- (b) Upon order by any court, the Commission or other duly authorized Public Authority; or
- (c) If fraudulent or unauthorized use of electricity is detected and the Company has reasonable grounds to believe the affected customer is responsible for such use; or
- (d) If the Company's regulating or measuring equipment has been tampered with and the Company has reasonable grounds to believe that the affected customer is responsible for such tampering.

16. SPECIAL SERVICE CHARGES.

The following schedule reflects the amounts to be charged for the special services stipulated. The Company will endeavor to comply with customer requested work subject to a minimum of three days prior notification and / or manpower availability.

SCHEDULE OF CHARGES	AMOUNT
1. Reconnect during regular business hours.	\$62.50
2. Reconnect during workday overtime hours and all day Saturday.	\$80
3. Reconnect on Sundays or holidays.	\$156.25
4. Trip charge where Company employees are sent to customer premises to specifically notify the customer that bill payment is due.	\$29.00
5. Disconnect trips where notification is left for the customer at the premises because of access or other issue , or the customer signs a Company form agreeing to make payment by the end of business the same day and no disconnect is made.	\$34.25
6. Reconnect when disconnect is required to be made from a vault, manhole, or service box.	\$585.75.
7. Reconnect when disconnect is required to be made at pole during regular business hours.	\$78.00
8. Reconnect when disconnect is required to be made at pole during workday overtime hours and all day Saturday.	\$117.00
9. Reconnect when disconnect is required to be made at pole on Sunday or holidays.	\$203.00
10. Trip charge for no-power service call when the customer's facilities are clearly at fault or for scheduled work and customer is not ready and the customer was advised of the charge.	\$34.25
11 Meter test or change when charge is permitted in accordance with the provision of MPSC Consumer Standards and Billing Practice Rules	\$31.25
12. Customer's check returned for nonsufficient funds.	\$18.75

(Continued on Sheet No. C-18.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. C-17.00)

17. MISCELLANEOUS CUSTOMER CHARGES

When the Company detects that its regulating, measuring equipment, or other facilities have been tampered with or when fraudulent or unauthorized use of electricity has occurred, a rebuttable presumption arises that the customer or other user has benefited by such fraudulent or unauthorized use of such tampering. Therefore, that customer or other user is responsible for payment of the reasonable cost of the service used during the period such fraudulent or unauthorized use or tampering occurred or is reasonably assumed to have occurred and is responsible for the cost of field calls and the cost of making repairs necessitated by such use and/or tampering, plus a charge of \$50 per occurrence. Under such circumstances the Company will institute the procedures outlined in the Consumer Standards and Billing Practice Rules. .

18. CUSTOMER OWNED EQUIPMENT TROUBLESHOOTING.

When requested by the customer to investigate any problems with customer owned equipment that is connected to the Company's system, such as a generator, transformer, or other unique customer-owned facilities, the Company will conduct investigations at no charge to the customer. Company will make all reasonable attempts to resolve any problems when the Company is found to be at fault. If the customer owned equipment is found to be at fault, the Company may at the customer's request, and upon mutual agreement, continue troubleshooting the problem if the customer consents to paying for all additional charges which shall be based on actual labor and material incurred.

19 VOLTAGES

The standard nominal distribution service voltages within the service area of the Company are:

Secondary		Primary	
Single Phase	Three Phase	Single Phase	Three Phase
120/240 Volts	120/208 Volts	2400 Volts**	4160/2400 Volts**
120/208 Volts	120/240 Volts*	7200 Volts	12470/7200 Volts
480 Volts	277/480 Volts	19950 Volts	34500/19950 Volts
	480 Volts*		
* Not available when supplied from 34500/19950 primary distribution systems.			
** Limited to existing 4160/2400 volt distribution systems or from a dedicated subtransmission or transmission station.			

(Continued on Sheet No. C-19.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. C-18.00)

The standard subtransmission and transmission service voltages within the service area of the Company are:

Subtransmission	Transmission
Three Phase	Three Phase
34.5 kV	138 kV
69 kV	345 kV
	765 kV

Voltages listed above are not available at all locations. The Company must be consulted regarding their availability at any particular location.

20. TAX ADJUSTMENT AND FRANCHISE FEES

Bills to customers receiving service within the limits of political subdivisions which levy special license fees, franchise fees or any other such fee against the Company or its operation or the production or sale of electric energy shall be increased by a uniform per meter surcharge calculated on an annual basis to offset such special fee or any new or increased special fee, thereby preventing other customers from being compelled to share such local fees.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

SECTION D

RATE TARIFFS

INDIANA MICHIGAN POWER COMPANY

**SCHEDULE OF TARIFFS
GOVERNING THE SALE OF ELECTRICITY
IN THE COMPANY’S SERVICE AREA**

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 – ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF RS
(Residential Electric Service)**

Availability of Service

Available for residential electric service through one meter to individual residential customers including rural residential customers engaged principally in agricultural pursuits.

Monthly Rate (Tariff Codes 015, 016 and 820)

	Power Supply		Delivery	Total
	Capacity	Non-Capacity		
Service Charge (\$)	--	--	7.25	7.25
Energy Charge (¢ per kWh)	2.983	6.6	2.927	12.51

Capacity and Non-Capacity Power Supply and Delivery Charges are applicable to Standard Service customers.

Capacity Power Supply and Delivery Charges only are applicable to Open Access Distribution customers.

Minimum Charge

This tariff is subject to a minimum monthly charge equal to the monthly service charge and all applicable riders

Low Income Service Charge Provision (Tariff Codes XXX)

Available to customers who qualify for Tariff RS that have a household income not to exceed 150 % of the poverty level, as published by the United States Department of Health and Human Services or who receive any of the following:

- (a) Assistance from a state emergency relief program.
- (b) Food stamps.
- (c) Medicaid.

The Company reserves the right to verify eligibility. This provision is not available for alternate or seasonal homes. This provision is subject to the service charge as stated below.

	Power Supply		Delivery	Total
	Capacity	Non-Capacity		
Low Income Service Charge	--	--	3.63	3.63

(Continued on Sheet No. D-3.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 – ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF RS
(Residential Electric Service)**

(Continued From Sheet No. D-2.00)

Storage Water-Heating Provision

This provision is closed except for the present installation of current customers receiving service hereunder at premises served prior to May 1, 1997.

If the customer installs a Company-approved storage water-heating system that consumes electrical energy only during off-peak hours as specified by the Company and stores hot water for use during on-peak hours, the following shall apply:

Tariff Code

- | | |
|-----|--|
| 012 | (a) For Minimum Capacity of 80 gallons, the last 300 kWh of use in any month shall be billed at the Storage Water-Heating Energy Charge. |
| 013 | (b) For Minimum Capacity of 100 gallons, the last 400 kWh of use in any month shall be billed at the Storage Water-Heating Energy Charge. |
| 014 | (c) For Minimum Capacity of 120 gallons or greater, the last 500 kWh of use in any month shall be billed at the Storage Water-Heating Energy Charge. |

	Power Supply		Delivery	Total
	Capacity	Non-Capacity		
Storage Water-Heating Energy Charge (¢ per kWh)	0.000 --	6.574	2.93	9.504

The above rates are available to Standard Service customers only.

These provisions, however, shall in no event apply to the first 200 kWh used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For purposes of this provision, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as all other hours in the week.

The Company reserves the right to inspect at all reasonable times the storage water-heating system and devices which qualify the residence for service under the Storage Water-Heating Provision, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that in its sole judgement the availability conditions of this tariff are being violated, it may discontinue billing the customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Service Charge as stated in the above monthly rate and all applicable riders.

(Continued on Sheet No. D-4.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 – ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF RS
(Residential Electric Service)**

(Continued From Sheet No. D-3.00)

Load Management Water-Heating Provision (Tariff Code 011)

This provision is closed except for the present installations of current customers receiving service at premises served prior to January 1, 2002.

For residential customers who install a Company-approved load management water-heating system which consumes electrical energy primarily during off-peak hours specified by the Company and stores hot water for use during on-peak hours, of minimum capacity of 80 gallons, the last 250 kWh of use in any month shall be billed at the Load Management Water-Heating Energy Charge.

	Power Supply		Delivery	Total
	Capacity	Non-Capacity		
Load Management Water-Heating Energy Charge (¢ per kWh)	-0- --	6.574	2.93	9.504

The above rates are available to Standard Service customers only.

This provision, however, shall in no event apply to the first 200 kWh used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For the purpose of this provision, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as all other hours in the week.

The Company reserves the right to inspect at all reasonable times the load management water-heating system(s) and devices which qualify the residence for service under the Load Management Water-Heating Provision. If the Company finds that in its sole judgement the availability conditions of this provision are being violated, it may discontinue billing the customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Service Charge as stated in the monthly rate and all applicable riders.

Space-Heating Provision

When service is supplied to a residence that has permanently installed electric-heating equipment as the primary source of space heating, all kWh used during the billing months of November through May (exclusive of storage or load management water-heating kWh) shall be billed at the Space-Heating Energy Charge.

~	Power Supply		Delivery	Total
	Capacity	Non-Capacity		
Space-Heating Energy Charge (¢ per kWh)	2.587	6.600	2.927	12.114

The above rates are available to Standard Service customers only.

This provision is subject to the Service Charge as stated in the above monthly rate and all applicable riders.

(Continued on Sheet No. D-5.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 – ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF RS
(Residential Electric Service)**

(Continued From Sheet No. D-4.00)

Delayed Payment Charge

A delayed payment charge of 2% of the unpaid balance shall be added to any delinquent bill as set forth in Rule 460.122 of the MPSC Rules. The due date shall be 21 days following the date of transmittal.

Applicable Riders

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. D-90.00.

Term of Contract

A written agreement may, at the Company's option, be required to fulfill the provisions of Items 1, 9, and/or 12 of the Terms and Conditions of Standard Service, or Items 1, 11, and/or 17 of the Terms and Conditions of Open Access Distribution Service, as applicable.

Special Terms And Conditions

This tariff is subject to the Company's Terms and Conditions of Standard Service, or Items 1, 11, and/or 17 of the Terms and Conditions of Open Access Distribution Service, as applicable.

This tariff is available for single-phase service only. Where three-phase power service is required and/or where motors or heating equipment are used for commercial or industrial purposes, the applicable power tariff will apply to such power service.

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS-1 (Net Metering Service for Customers With Generating Facilities of 20 kW or Less, Rider NMS-2 (Net Metering Service for Customers with Generating Facilities Greater than 20 kW), Tariff COGEN/SPP or by special agreement with the Company.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF RS-TOD
(Residential Time-of-Day Service)**

Availability of Service

Available for residential electric service through one single-phase, multi-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods to individual residential customers, including residential customers engaged principally in agricultural pursuits, who take Standard Service from the Company.

Monthly Rate (Tariff Code 030)

	Power Supply		Delivery	Total
	Capacity	Non-Capacity		
Service Charge (\$)	--		9.15	9.15
Energy Charge (¢ per kWh): For all on-peak kWh used	5.344	6.574	2.930	14.848
For all off-peak kWh used	-0-	6.574	2.930	9.504

For the purpose of this tariff, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as all other hours in the week.

Minimum Charge

This tariff is subject to a minimum charge equal to the monthly service charge and all applicable riders.

Delayed Payment Charge

A delayed payment charge of 2% of the unpaid balance shall be added to any delinquent bill as set forth in Rule 460-122 of the MPSC rules. The due date shall be 21 days following the date of transmittal.

Applicable Riders

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. D-90.00.

(Continued on Sheet No. D-7.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF RS-TOD
(Residential Time-of-Day Service)**

(Continued From Sheet No. D-6.00)

Term of Contract

A written agreement may, at the Company's option, be required to fulfill the provisions of Item 1, 9, and/or 12 of the Terms and Conditions of Standard Service.

Special Terms And Conditions

This tariff is subject to the Company's Terms and Conditions of Standard Service.

This tariff is available for single-phase service only. Where three-phase power service is required and/or where motors or heating equipment are used for commercial or industrial purposes, the applicable power tariff will apply to such power service.

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS-1 (Net Metering Service for Customers With Generating Facilities of 20 kW or Less, Rider NMS-2 (Net Metering Service for Customers with Generating Facilities Greater than 20 kW), Tariff COGEN/SPP or by special agreement with the Company.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**TARIFF RS-OPES/PEV
(Residential Off-Peak Energy Storage/Plug-In Electric Vehicle)**

Availability of Service

Available to customers eligible for Tariff RS (Residential Service) who use energy storage devices with time-differentiated load characteristics approved by the Company, such as electric thermal storage space-heating equipment and water heaters which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and/or customers using charging stations for Plug-In Electric Vehicles (PEV) programmed to consume electrical energy primarily during off-peak hours specified by the Company, who take Standard Service from the Company.

Households eligible to be served under this Tariff shall be metered through one single-phase, multi-register meter capable of measuring electrical energy consumption during on-peak and off-peak billing periods. For PEVs, metering shall be installed at the Company's discretion that is capable of separately identifying PEV usage. Customer-specific information will be held as confidential and the data presented in any analysis will protect the identity of the individual customer.

Monthly Rate (Tariff Code 032)

	Power Supply		Delivery	Total
	Capacity	Non-Capacity		
Service Charge (\$)	--		9.15	9.15
Energy Charge (¢ per kWh):				
For all on-peak kWh used	5.344	6.574	2.930	14.848
For all off-peak kWh used	-0-	6.574	2.930	9.504

For the purpose of this tariff, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as all other hours in the week.

Thermal Storage Equipment Conservation and Load Management Credit

For the combination of an approved electrical thermal storage space-heating system and water heater, both of which are designed to consume electrical energy only during the off-peak billing period as previously described in this tariff, each residence will receive a generation credit of 0.00¢ for all off-peak kWh used, for a total of 60 monthly billing periods following the installation and use of these devices in such residence.

Experimental Electrical Vehicle Supply Equipment (EVSE) Option

The first 250 customers opting to obtain service under this tariff for the purpose of charging plug-in electric vehicles registered and operable on public highways in the State of Michigan may choose to have the Company reimburse up to \$2,500 toward the purchase of Company approved Electric Vehicle Supply Equipment. EVSE is defined as the charging station including conductors, the ungrounded, grounded, and equipment grounding conductors, the electric vehicle connectors, attachment plugs, and all other fittings, devices, power outlets, or apparatus installed specifically for the purpose of delivering electric energy from the premises wiring to the plug-in electric vehicle (if not otherwise provided) and installation costs of a separately metered circuit

(Continued on Sheet No. D-9.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**TARIFF RS-OPES/PEV
(Residential Off-Peak Energy Storage/Plug-In Electric Vehicle)**

(Continued From Sheet No. D-8.00)

All installations shall be performed by a Company approved contractor and must conform to Company specifications. Customers choosing service under the EVSE Option must execute a contract with Company that specifies the terms and conditions of the agreement including proof of purchase of a qualifying PEV.

Minimum Charge

This tariff is subject to a minimum monthly charge equal to the monthly service charge and all applicable riders.

Separate Metering Provision

Customers shall have the option of receiving service under Tariff RS for their general-use load by separately wiring this equipment to a standard residential meter.

Delayed Payment Charge

A delayed payment charge of 2% of the unpaid balance shall be added to any delinquent bill as set forth in Rule 460-122 of the MPSC rules. The due date shall be 21 days following the date of transmittal.

Applicable Riders

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. D-90.00.

Term of Contract

A written agreement may, at the Company's option, be required to fulfill the provisions of Items 1, 9, and/or 12 of the Terms and Conditions of Standard Service.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Standard Service.

The Company reserves the right to inspect at all reasonable times the energy storage and load management devices which qualify the residence for service, for conservation and load management credits, and for EVSE Option reimbursements under this tariff, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that in its sole judgement the availability conditions of this tariff are being violated, it may discontinue billing the customer under this tariff and commence billing under the appropriate Residential Service Tariff.

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS-1 (Net Metering Service for Customers With Generating Facilities of 20 kW or Less, Rider NMS-2 (Net Metering Service for Customers with Generating Facilities Greater than 20 kW), Tariff COGEN/SPP or by special agreement with the Company.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF R.S. – TOD2
(Residential Time-of-Day Service)**

Availability of Service.

Available for residential electric service through one single-phase, multi-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods to individual residential customers, including residential customers engaged principally in agricultural pursuits, who take Standard Service from the Company. Availability is restricted to the first 300 customers applying for service under this tariff.

Monthly Rate (Tariff Codes 021)

	Power Supply		Delivery	Total
	Capacity	Non-Capacity		
Service Charge (\$)	--		9.15	9.15
Energy Charge (¢ per kWh):				
High Cost Hours (P2)	10.282	6.573	2.927	19.782
Low Cost Hours (P1)	2.379	6.573	2.927	11.879

Billing Hours.

Months	Low Cost Hours (P1)	High Cost Hours (P2)
Approximate Percent(%) of Annual Hours	95%	5%
October through April	All Hours	None
May through September	Midnight to 2 PM, 6 PM to Midnight	2 PM to 6 PM

NOTES: All times indicated above are local time.
All kWh consumed during weekends are billed at the low cost (P1) level.

Delayed Payment Charge

A delayed payment charge of 2% of the unpaid balance shall be added to any delinquent bill as set forth in Rule 460-122 of the MPSC rules. The due date shall be 21 days following the date of transmittal.

Applicable Riders

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. D-90.00.

(Continued on Sheet No. D-11.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF R.S. – TOD2
(Residential Time-of-Day Service)**

(Continued from Sheet No. D-10.00)

Term of Contract

A written agreement may, at the Company's option, be required to fulfill the provisions of Items 1, 9, and/or 12 of the Terms and Conditions of Standard Service.

Special Terms And Conditions

This tariff is subject to the Company's Terms and Conditions of Standard Service.

This tariff is available for single-phase service only. Where three-phase power service is required and/or where motors or heating equipment are used for commercial or industrial purposes, the applicable power tariff will apply to such power service.

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS-1 (Net Metering Service for Customers With Generating Facilities of 20 kW or Less, Rider NMS-2 (Net Metering Service for Customers with Generating Facilities Greater than 20 kW), Tariff COGEN/SPP or by special agreement with the Company.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF RS-SC
(Optional Residential Senior Citizen)**

Availability of Service

Available to qualified customers desiring service for residential uses which include only those purposes which are usual in individual private family dwellings or separately metered apartments and in the usual appurtenant buildings served through the residential meter who take Standard Service from the Company. This rate is not available for commercial or industrial service, for resale purposes, or for alternate residence. To qualify for this rate, the customer must be 65 years of age and head of the household.

The optional rate is not available for an alternate or seasonal home and the customer shall contract to remain on this rate for at least 12 months.

Monthly Rate (Tariff Codes 023)

	Power Supply		Delivery	Total
	Capacity	Non-Capacity		
Service Charge (\$)	--		9.00	9.00
Energy Charge (¢ per kWh):				
For the first 300 kWh used per month	-0-	6.574	3.292	9.866
For the next 600 kWh used per month	2.587	6.600	3.289	12.476
For all kWh over 900 used per month	14.308	6.678	3.280	24.266

Minimum Charge

This tariff is subject to a minimum monthly charge equal to the monthly service charge and all applicable riders.

Storage Water-Heating Provision

This provision is closed except for the present installation of current customers receiving service hereunder at premises served prior to May 1, 1997.

If the customer installs a Company-approved storage water-heating system that consumes electrical energy only during off-peak hours as specified by the Company and stores hot water for use during on-peak hours, the following shall apply:

(Continued on Sheet No.D-13.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF RS-SC
(Optional Residential Senior Citizen)**

(Continued From Sheet No. 12.00)

Tariff Code

- 024 For Minimum Capacity of 80 gallons, the last 300 kWh of use in any month shall be billed at the Storage Water-Heating Energy Charge.
- 025 For Minimum Capacity of 100 gallons, the last 400 kWh of use in any month shall be billed at the Storage Water-Heating Energy Charge.
- 026 (c) For Minimum Capacity of 120 gallons or greater, the last 500 kWh of use in any month shall be billed at the Storage Water-Heating Energy Charge.

	Power Supply		Delivery	Total
	Capacity	Non-Capacity		
Storage Water-Heating Energy Charge (¢ per kWh)	-0-	6.574	2.930	9.504

These provisions, however, shall in no event apply to the first 200 kWh used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For purposes of this provision, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as all other hours in the week.

The Company reserves the right to inspect at all reasonable times the storage water-heating system and devices which qualify the residence for service under the Storage Water-Heating Provision, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that in its sole judgement the availability conditions of this tariff are being violated, it may discontinue billing the customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Service Charge as stated in the above monthly rate and all applicable riders.

Load Management Water-Heating Provision (Tariff Code 027)

This provision is closed except for the present installations of current customers receiving service at premises served prior to January 1, 2002.

(Continued on Sheet No. D-14.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-14.00

**TARIFF RS-SC
(Optional Residential Senior Citizen)**

(Continued From Sheet No. D-13.00)

For residential customers who install a Company-approved load management water-heating system which consumes electrical energy primarily during off-peak hours specified by the Company and stores hot water for use during on-peak hours, of minimum capacity of 80 gallons, the last 250 kWh of use in any month shall be billed at the Load Management Water-Heating Energy Charge.

	Power Supply		Delivery	Total
	Capacity	Non-Capacity		
Load Management Water-Heating Energy Charge (¢ per kWh)	-0-	6.574	2.930	9.504

This provision, however, shall in no event apply to the first 200 kWh used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For the purpose of this provision, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as all other hours in the week.

The Company reserves the right to inspect at all reasonable times the load management water-heating system(s) and devices which qualify the residence for service under the Load Management Water-Heating Provision. If the Company finds that in its sole judgement the availability conditions of this provision are being violated, it may discontinue billing the customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Service Charge as stated in the above monthly rate and all applicable riders.

Delayed Payment Charge

A delayed payment charge of 2% of the unpaid balance shall be added to any delinquent bill as set forth in Rule 460-122 of the MPSC rules. The due date shall be 21 days following the date of transmittal.

Applicable Riders

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. D-90.00.

(Continued on Sheet No. D-15.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF RS-SC
(Optional Residential Senior Citizen)**

(Continued From Sheet No. D-14.00)

Term of Contract

Contracts under this tariff will be made for a minimum of 12 months.

Special Terms And Conditions

This tariff is subject to the Company's Terms and Conditions of Standard Service.

This tariff is available for single-phase service only. Where three-phase power service is required and/or where motors or heating equipment are used for commercial or industrial purposes, the applicable power tariff will apply to such power service.

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS-1 (Net Metering Service for Customers With Generating Facilities of 20 kW or Less, Rider NMS-2 (Net Metering Service for Customers with Generating Facilities Greater than 20 kW), Tariff COGEN/SPP or by special agreement with the Company.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-16.00

**TARIFF GS
(General Service)**

Availability of Service

Available for general service customers. Customers may continue to qualify for service under this tariff until their 12-month average metered demands exceeds 1,500 kW.

Monthly Rate

Tariff Codes	Voltage	Power Supply		Delivery	Total
		Capacity	Non-Capacity		
215, 218 & 840	Secondary				
	Service Charge (\$)				
	Customers w/o Demand Meter			6.25	6.25
	Customers with Demand Meter			17.45	17.45
	Demands Greater Than 10 kW (\$ per kW)	1.23	2.05	6.53	9.81
	First 4,500 kWh (¢ per kWh)	3.136	5.508	2.362	11.006
	Over 4,500 kWh	2.649	6.921	-0-	9.570
217 & 841	Primary				
	Service Charge (\$)			165.00	165.00
	Demands Greater than 10 kW (\$ per kW)	1.20	2.00	3.72	6.92
	First 4,500 kWh (¢ per kWh)	3.041	5.336	2.288	10.665
	Over 4,500 kWh (¢ per kWh)	2.569	6.705	-0-	9.274
236 & 842	Subtransmission				
	Service Charge (\$)			165.00	165.00
	Demands Greater Than 10 kW (\$ per kW)	1.17	1.96	-0-	3.13
	First 4,500 kWh (¢ per kWh)	2.992	5.250	2.251	10.493
	Over 4,500 kWh (¢ per kWh)	2.528	6.597	-0-	9.125

Capacity and Non-Capacity Power Supply and Delivery Charges are applicable to Standard Service customers.
Capacity Power Supply and Delivery Charges only are applicable to Open Access Distribution customers.

Minimum Charge

Bills computed under the above rate are subject to the operation of minimum charge provisions as follows:

- (a) Minimum Charge - For demand accounts up to 100 kW - the service charge and all applicable riders.
- For demand accounts over 100 kW - the sum of the service charge, the product of the demand charge and the monthly billing demand, and all applicable riders.

(Continued on Sheet No. D-17.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-17.00

**TARIFF GS
(General Service)**

(Continued From Sheet No. D-16.00)

Metered Voltage

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss-compensating equipment, the use of formulas to calculate losses, or the application of multipliers to the metered quantities. In such cases, the metered kWh and kW values will be adjusted for billing purposes. If the Company elects to adjust kWh and kW based on multipliers, the adjustment shall be in accordance with the following:

- (1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.
- (2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Monthly Billing Demand

Energy supplied hereunder will be delivered through not more than one single-phase or one polyphase meter. Billing demand in kW shall be taken each month as the single highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator or, at the Company's option, as the highest registration of a thermal-type demand meter or indicator. Where energy is presently delivered through two meters, the billing demand shall be taken as the sum of the two demands separately determined.

The minimum monthly billing demand established hereunder shall not be less than 60% of the greater of (a) the customer's contract capacity in excess of 100 kW or (b) the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 kW.

The minimum monthly billing demand shall not be less than 25% of the greater of (a) the customer's contract capacity in excess of 100 kW or (b) the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 kW during the billing months of May through November for customers with more than 50% of their connected load used for space heating purposes.

The Metered Voltage adjustment, as set forth above, shall not apply to the customer's minimum monthly billing demand.

Billing demands shall be rounded to the nearest whole kW and will be applied to monthly demands in excess of 10 kW. The Company will install a demand meter on any customer receiving service under this tariff with an average kWh usage of 4,500 or greater and at the Company option for customers with average kWh of less than 4,500.

(Continued on Sheet No. D-18.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-18.00

**TARIFF GS
(General Service)**

(Continued From Sheet No. D-17.00)

Delayed Payment Charge

A delayed payment charge of 2% of the total net bill shall be added to any bill which is not paid on or before the due date shown thereon as set forth in Rule 460.1614, of the MPSC Rules. The due date shall be 22 days following the date of transmittal.

Applicable Riders

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. D-90.00.

Term of Contract

Service under this tariff will be for an initial period of not less than one year and shall remain in effect thereafter until either party shall give at least six months' written notice to the other of the intention to discontinue service under the terms of this tariff. A written agreement may, at the Company's option, be required to fulfill the provisions of Items 1, 9, and/or 12 of the Terms and Conditions of Standard Service, or Items 1, 11, and/or 17 of the Terms and Conditions of Open Access Distribution Service, as applicable.

A new initial period will not be required for existing customers who increase their requirements after the original initial period unless new or additional facilities are required.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

The Company may not be required to supply capacity in excess of that contracted for except by mutual agreement.

Notwithstanding any contractual requirement for longer than 90 days' notice to discontinue Standard Service, customers may elect to take service from a qualified Alternate Electric Supplier (AES), pursuant to the Terms and Conditions of Open Access Distribution Service, by providing 90 days' written notice to the Company. If upon completion of such 90-day notice period the customer has not enrolled with a qualified AES, then the customer must continue to take Standard Service for a period of not less than 12 consecutive months.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Standard Service, and Terms and Conditions of Open Access Distribution Service, as applicable.

This tariff is also available to Standard Service customers having other sources of energy supply, but who desire to purchase standby or backup electric service from the Company. Where such conditions exist, the customer shall contract for the maximum amount of demand in kW, which the Company might be required to furnish, but not less than 10 kW.

(Continued on Sheet No. D-19.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-19.00

**TARIFF GS
(General Service)**

(Continued From Sheet No. D-18.00)

The Company shall not be obligated to supply demands in excess of that contracted for. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

Standard Service customers with cogeneration and/or small power production facilities shall take service under Rider NMS-1 (Net Metering Service for Customers With Generating Facilities of 20 kW or Less, Rider NMS-2 (Net Metering Service for Customers with Generating Facilities Greater than 20 kW), Tariff COGEN/SPP or by special agreement with the Company.

OAD Customers with cogeneration, small power production facilities, or other on-site sources of electric energy designed to operate in parallel with the Company's system shall take service by special agreement with the Company.

Load Management Time-of-Day Provision

Available to Standard Service customers who use energy storage devices with time-differentiated load characteristics approved by the Company, such as electric thermal storage space-heating furnaces and water heaters which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and take Standard Service from the Company.

Customers shall have the option of receiving service under Tariff GS for their general-use load by separately wiring this equipment to a standard meter.

The customer shall be responsible for all local facilities required to take service under this provision.

Monthly Rate (Tariff Code 223)

Voltage	Power Supply		Delivery	Total
	Capacity	Non-Capacity		
Secondary				
Service Charge (\$)				
Customers w/o Demand Meter			7.45	7.45
Customers with Demand Meter			17.65	17.65
Energy Charge (¢ per kWh):				
For all on-peak kWh used	5.117	6.922	2.547	14.586
For all off-peak kWh used	-0-	6.922	2.547	9.469

The above rates are available to Standard Service customers only.

For the purpose of this provision, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as all other hours in the week.

This provision is subject to the terms and conditions of Tariff GS including all applicable riders.

(Continued on Sheet No. D-20.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-20.00

**TARIFF GS
(General Service)**

(Continued From Sheet No. D-19.00)

Optional Unmetered Service Provision

Available to customers who qualify for Tariff GS, use the Company's service for commercial purposes consisting of small fixed electric loads such as traffic signals and signboards. This service will be furnished at the option of the Company.

Each separate service delivery point shall be considered a contract location and shall be separately billed under the service contract. In the event one customer has several accounts for like service, the Company may meter one account to determine the appropriate kilowatt-hour usage applicable for each of the accounts.

The customer shall furnish switching equipment satisfactory to the Company. The customer shall notify the Company in advance of every change in connected load or change in operation and the Company reserves the right to inspect the customer's equipment at any time to verify the actual energy consumption. In the event of the customer's failure to notify the Company of an increase in load, the Company reserves the right to refuse to serve the contract location thereafter under this provision, and shall be entitled to bill the customer retroactively on the basis of the increased load as provided in the MPSC Consumer Standards and Billing Practice Rules .

Calculated energy use per month shall be equal to the contract capacity specified at the contract location times the number of days in the billing period times the specified hours of operation.

Monthly Rate (Tariff Codes 214, 204 and 831)

	<u>Power Supply</u>		<u>Delivery</u>	<u>Total</u>
	<u>Capacity</u>	<u>Non-Capacity</u>		
Service Charge (\$)	--	--	5.00	5.00
Energy Charge (¢ per kWh): For all kWh used per month	3.136	5.508	2.362	11.006

Capacity and Non-Capacity Power Supply and Delivery Charges are applicable to Standard Service customers.
Capacity Power Supply and Delivery Charges only are applicable to Open Access Distribution customers.

This provision is subject to the terms and conditions of Tariff GS including all applicable riders.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-21.00

**TARIFF GS-TOD
(General Service - Time-of-Day)**

Availability of Service

Available for general service customers with 12-month average metered demands not greater than 150 kW who take Standard Service from the Company. Availability is limited to secondary service. This tariff is closed to customers with 12-month average metered demands greater than 150 kW except for current Tariff MGS-TOD customers in the former Three Rivers Rate Area receiving service as of November 29, 2010.

Monthly Rate (Tariff Code 229)

Voltage	Power Supply		Delivery	Total
	Capacity	Non-Capacity		
Secondary				
Service Charge (\$)				
Customers w/o Demand Meter			7.45	7.45
Customers with Demand Meter			17.65	17.65
Energy Charge (¢ per kWh):				
For all on-peak kWh used	5.117	6.922	2.547	14.586
For all off-peak kWh used	-0-	6.922	2.547	9.469

For the purpose of this tariff, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as all other hours in the week.

Minimum Charge

This tariff is subject to a minimum monthly charge equal to the monthly service charge and all applicable riders.

Metered Voltage

The rates set forth in this tariff are based upon the delivery and measurement of energy at the secondary voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss-compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered kWh values will be adjusted for billing purposes. If the Company elects to adjust kWh based on multipliers, the adjustment shall be 0.98 when measurements are taken at the high-side of a Company-owned transformer.

Delayed Payment Charge

A delayed payment charge of 2% of the total net bill shall be added to any bill which is not paid on or before the due date shown thereon as set forth in Rule 460.1614, of the MPSC rules. The due date shall be 22 days following the date of transmittal.

(Continued on Sheet No. D-22.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-22.00

**TARIFF GS-TOD
(General Service - Time-of-Day)**

(Continued From Sheet No. D-21.00)

Applicable Riders

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. D-90.00.

Term of Contract

A written agreement may, at the Company's option, be required to fulfill the provisions of Items 1, 9, and/or 12 of the Terms and Conditions of Standard Service.

Notwithstanding any contractual requirement for longer than 90 days' notice to discontinue Standard Service, customers may elect to take service from a qualified Alternate Electric Supplier (AES), pursuant to the Terms and Conditions of Open Access Distribution Service, by providing 90 days' written notice to the Company. If upon completion of such 90-day notice period the customer has not enrolled with a qualified AES, then the customer must continue to take Standard Service for a period of not less than 12 consecutive months.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Standard Service.

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS-1 (Net Metering Service for Customers With Generating Facilities of 20 kW or Less, Rider NMS-2 (Net Metering Service for Customers with Generating Facilities Greater than 20 kW), Tariff COGEN/SPP or by special agreement with the Company.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-23.00

**TARIFF G.S. – TOD2
(General Service Time-of-Day 2 Service)**

Availability of Service.

Available for general service to customers with 12-month average metered demands of less than 10 kW through one single-phase, multi-register meter capable of measuring electrical energy consumption during variable pricing periods who take Standard Service from the Company. Availability is restricted to the first 50 customers applying for service under this tariff.

Rate. (Tariff Code: 221)

	Power Supply		<u>Delivery</u>	<u>Total</u>
	<u>Capacity</u>	<u>Non-Capacity</u>		
Service Charge (\$)			7.45	7.45
Customers w/o Demand Meter	--		17.65	17.65
Customers with Demand Meter				
Energy Charge (¢ per kWh):				
High Cost Hours (P2)	8.854	6.915	2.686	18.455
Low Cost Hours (P1)	-0-	6.915	2.686	12.236

Billing Hours.

Months	Low Cost Hours (P1)	High Cost Hours (P2)
Approximate Percent (%) Of Annual Hours	95%	5%
October through April	All Hours	None
May through September	Midnight to 2 PM, 6 PM to Midnight	2 PM to 6 PM

NOTES: All times indicated above are local time.
All kWh consumed during weekends are billed at the low cost (P1) level.

Minimum Charge.

This tariff is subject to a minimum monthly charge equal to the monthly service charge and all applicable riders.

(Continued on Sheet No. D-24.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

EFFECTIVE FOR SERVICE RENDERED ON

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF G.S. – TOD2
(General Service Time-of-Day 2 Service)**

(Continued from Sheet No. D-23.00)

Delayed Payment Charge.

A delayed payment charge of 2% of the unpaid balance shall be added to any delinquent bill as set forth in the MPSC Consumer Standards and Billing Practice Rules. The due date shall be 22 days following the date of transmittal.

Applicable Riders

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. D-90.00.

Term of Contract

A written agreement may, at the Company's option, be required to fulfill the provisions of Items 1, 9, and/or 12 of the Terms and Conditions of Standard Service, or Items 1, 11, and/or 17 of the Terms and Conditions of Open Access Distribution Service, as applicable.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Standard Service.

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS-1 (Net Metering Service for Customers With Generating Facilities of 20 kW or Less, Rider NMS-2 (Net Metering Service for Customers with Generating Facilities Greater than 20 kW), Tariff COGEN/SPP or by special agreement with the Company.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF LGS
(Large General Service)**

Availability of Service

Available for general service customers with metered demands greater than 100 kW. Customers may continue to qualify for service under this tariff until their 12-month average metered demand exceeds 1,500 kW.

Monthly Rate

Tariff Codes	Voltage	Power Supply		Delivery	Total
		Capacity	Non-Capacity		
240, 242 & 850	Secondary				
	Service Charge (\$)	--	--	44.00	44.00
	Demand Charge (\$ per kW)	3.40	6.32	7.60	17.32
	Energy Charge (¢ per kWh): For all on-peak kWh used	3.491	4.702	--	8.193
	For all off-peak kWh used	--	4.702	--	4.702
244 & 851	Primary				
	Service Charge (\$)	--	--	207.00	207.00
	Demand Charge (\$ per kW)	3.31	6.16	4.74	14.21
	Energy Charge (¢ per kWh): For all on-peak kWh used	3.379	4.555	--	7.934
	For all off-peak kWh used	--	4.555	--	4.555
248 & 852	Subtransmission				
	Service Charge (\$)			207.00	207.00
	Demand Charge (\$ per kW)	3.26	6.05	--	9.31
	Energy Charge (¢ per kWh): For all on-peak kWh used	3.326	4.482	--	7.808
	For all off-peak kWh used	--	4.482	--	4.482

Capacity and Non-Capacity Power Supply and Delivery Charges are applicable to Standard Service customers. Capacity Power Supply and Delivery Charges only are applicable to Open Access Distribution customers.

For the purpose of this tariff, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as all other hours in the week.

Minimum Charge

This tariff is subject to a minimum monthly charge equal to the sum of the service charge, the product of the demand charge and the monthly billing demand, and all applicable riders. The power factor clause shall not operate to change the monthly minimum charge.

(Continued on Sheet No. D-26.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF LGS
(Large General Service)**

(Continued From Sheet No. D-25.00)

Monthly Billing Demand

Energy supplied hereunder will be delivered through not more than one single-phase or one polyphase meter. Billing demand in kW shall be taken each month as the single highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator or, at the Company's option, as the highest registration of a thermal-type demand meter or indicator, subject to the off - peak hour provision.

Where energy is presently delivered through two meters, the billing demand will be taken as the sum of the two demands separately determined.

The minimum monthly billing demand established hereunder shall not be less than 60% of the greater of (a) the customer's contract capacity, or (b) the customer's highest previously established monthly billing demand during the past 11 months, or (c) 100 kW.

The minimum monthly billing demand shall not be less than 25% of the greater of (a) the customer's contract capacity, or (b) the customer's highest previously established monthly billing demand during the past 11 months, or (c) 100 kW during the billing months of May through November for customers with more than 50% of their connected load used for space-heating purposes.

The Metered Voltage adjustment, as set forth below, shall not apply to the customer's minimum monthly billing demand.

Billing demands shall be rounded to the nearest whole kW.

Off-Peak Hour Provision – Applicable to Standard Service customers only.

Demand created during the off-peak billing period shall be disregarded for billing purposes provided that the billing demand shall not be less than 60% of the maximum demand created during the billing month.

Availability of this provision is subject to the availability of capacity in the Company's existing facilities.

Adjustments to Rate

Bills computed under the rate set forth herein will be adjusted as follows:

(Continued on Sheet No. D-27.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF LGS
(Large General Service)**

(Continued From Sheet No. D-26.00)

A. Power Factor

The rate set forth in this tariff is subject to power factor adjustment based upon the maintenance by the customer of an average monthly power factor of 85%, leading or lagging, as measured by integrating meters. When the average monthly power factor is above or below 85%, leading or lagging, the on-peak and off-peak kWh as metered will, for billing purposes, be multiplied by the constant, rounded to the nearest 0.0001, derived from the following formula:

$$\text{Constant} = 0.9510 + \left[0.1275 \left[\frac{\text{RKVAH}}{\text{KWH}} \right]^2 \right]$$

In no event shall the Constant derived from the above formula be greater than 2.0000.

B. Metered Voltage

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss-compensating equipment, the use of formulas to calculate losses, or the application of multipliers to the metered quantities. In such cases, the metered kWh and kW values will be adjusted for billing purposes. If the Company elects to adjust kWh and kW based on multipliers, the adjustment shall be in accordance with the following:

- (1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.
- (2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Delayed Payment Charge

A delayed payment charge of 2% of the total net bill shall be added to any bill which is not paid on or before the due date shown thereon as set forth in Rule 460.1614, of the MPSC Rules. The due date shall be 22 days following the date of transmittal.

Applicable Riders

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. D-90.00.

(Continued on Sheet No. D-28.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF LGS
(Large General Service)**

(Continued From Sheet No. D-27.00)

Term of Contract

Service under this tariff will be for an initial period of not less than one year and shall remain in effect thereafter until either party shall give at least six months' written notice to the other of the intention to discontinue service under the terms of this tariff. A written agreement may, at the Company's option, be required to fulfill the provisions of Items 1, 9, and/or 12 of the Terms and Conditions of Standard Service, or Items 1, 11, and/or 17 of the Terms and Conditions of Open Access Distribution Service, as applicable.

A new initial period will not be required for existing customers who increase their requirements after the original initial period unless new or additional facilities are required.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

The Company may not be required to supply capacity in excess of that contracted for except by mutual agreement.

Notwithstanding any contractual requirement for longer than 90 days' notice to discontinue Standard Service, customers may elect to take service from a qualified Alternate Electric Supplier (AES), pursuant to the Terms and Conditions of Open Access Distribution Service, by providing 90 days' written notice to the Company. If upon completion of such 90-day notice period the customer has not enrolled with a qualified AES, then the customer must continue to take service under the Company's Standard Service for a period of not less than 12 consecutive months.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Standard Service, or Items 1, 11, and/or 17 of the Terms and Conditions of Open Access Distribution Service, as applicable.

This tariff is also available to customers having other on-site sources of electric energy supply, who purchase standby or backup service from the Company. Where such conditions exist, the customer shall contract for the maximum amount of demand in kW, which the Company might be required to furnish, but not less than 100 kW. The Company shall not be obligated to supply demands in excess of that contracted for. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

(Continued on Sheet No. D-29.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF LGS
(Large General Service)**

(Continued From Sheet No. D-28.00)

contract for the maximum amount of demand in kW, which the Company might be required to furnish, but not less than 100 kW. The Company shall not be obligated to supply demands in excess of that contracted for. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

Standard Service customers with cogeneration and/or small power production facilities shall take service under Rider NMS-1 (Net Metering Service for Customers With Generating Facilities of 20 kW or Less, Rider NMS-2 (Net Metering Service for Customers with Generating Facilities Greater than 20 kW), Tariff COGEN/SPP or by special agreement with the Company.

OAD Customers with cogeneration or small power production facilities designed to operate in parallel with the Company's system shall take service by special agreement with the Company.

Load Management Time-of-Day Provision

Available to Standard Service customers who use energy storage devices with time-differentiated load characteristics approved by the Company, such as electric thermal storage space-heating furnaces and water heaters which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and take Standard Service from the Company.

Customers shall have the option of receiving service under Tariff LGS for their general-use load by separately wiring this equipment to a standard meter.

The customer shall be responsible for all local facilities required to take service under this provision.

Monthly Rate (Tariff Code 251)

Voltage	Power Supply		Delivery	Total
	Capacity	Non-Capacity		
Secondary				
Service Charge (\$)	--		44.00	44.00
Energy Charge (¢ per kWh):				
For all on-peak kWh used	4.998	5.927	1.628	12.553
For all off-peak kWh used	--	5.927	1.628	7.555

The above rates are available to Standard Service customers only.

For purpose of this provision, the on-peak and off-peak billing periods are the same as previously described in this tariff.

This provision is subject to the terms and conditions of Tariff LGS including all applicable riders.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-30.00

**TARIFF LP
(Large Power)**

Availability of Service

Available for general service customers. The customer shall contract for a sufficient capacity to meet normal maximum requirements, but in no case shall the capacity contracted for be less than 1,500 kW.

Monthly Rate

Tariff Codes	Voltage	Power Supply		Delivery	Total
		Capacity	Non-Capacity		
305 & 860	Secondary				
	Service Charge (\$)	--	--	44.00	44.00
	Demand Charge (\$ per kW)	6.85	12.83	7.74	27.42
	Energy Charge (¢ per kWh):	2.075	3.255	-	5.330
	For the first 210 on-peak kWh used per kW	--	3.255	-	3.255
	For all over 210 on-peak kWh used per kW	--	3.255	-	3.255
	For all off-peak kWh used				
Tariff Codes	Voltage	Power Supply		Delivery	Total
		Capacity	Non-Capacity		
306 & 861	Primary				
	Service Charge (\$)	--	--	259.00	259.00
	Demand Charge (\$ per kW)	6.67	12.50	4.88	24.05
	Energy Charge (¢ per kWh):	2.010	3.153	--	5.163
	For the first 210 on-peak kWh used per kW	--	3.153	--	3.153
	For all over 210 on-peak kWh used per kW	--	3.153	--	3.153
	For all off-peak kWh used				
308 & 862	Subtransmission				
	Service Charge (\$)	--	--	880.00	880.00
	Demand Charge (\$ per kW)	6.56	12.29	0.28	19.13
	Energy Charge (¢ per kWh):	1.978	3.102	--	5.080
	For the first 210 on-peak kWh used per kW	--	3.102	--	3.102
	For all over 210 on-peak kWh used per kW	--	3.102	--	3.102
	For all off-peak kWh used				

(Continued on Sheet No. D-31.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF LP
(Large Power)**

(Continued From Sheet No. D-30.00)

310 & 863	Transmission				
	Service Charge (\$)	--	--	880.00	880.00
	Demand Charge (\$ per kW)	6.46	12.09	0.17	18.72
	Energy Charge (¢ per kWh):				
	For the first 210 on-peak kWh used per kW	1.953	3.058	--	5.011
	For all over 210 on-peak kWh used per kW	--	3.058	--	3.058
	For all off-peak kWh used	--	3.058	--	3.058

Capacity and Non-Capacity Power Supply and Delivery Charges are applicable to Standard Service customers.
Capacity Power and Delivery Charges only are applicable to Open Access Distribution customers.

For the purpose of this tariff, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as all other hours in the week.

Minimum Charge

This tariff is subject to a minimum monthly charge equal to the monthly service charge, plus the product of the demand charge and the monthly billing demand, and all applicable riders. The power factor clause shall not operate to change the monthly minimum charge.

Monthly Billing Demand

The billing demand in kW shall be taken each month as the single highest 15-minute integrated peak in kW, as registered during the month by a demand meter or indicator, subject to off-peak hour provision, but the monthly billing demand so established shall, in no event, be less than 60% of the greater of (a) the customer's contract capacity, (b) the customer's highest previously established monthly billing demand during the past 11 months, or (c) 1,500 kW.

The Metered Voltage adjustment, as set forth below, shall not apply to the customer's minimum monthly billing demand.

Billing demands shall be rounded to the nearest whole kW.

Off-Peak Hour Provision – Applicable to Standard Service customers only.

Demand created during the off-peak billing period shall be disregarded for billing purposes provided that the billing demand shall not be less than 60% of the maximum demand created during the billing month.

Availability of this provision is subject to the availability of capacity in the Company's existing facilities.

(Continued on Sheet No. D-32.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF LP
(Large Power)**

(Continued From Sheet No. D-31.00)

Adjustments to Rate

Bills computed under the rate set forth herein will be adjusted as follows:

A. Power Factor

The rates set forth in this tariff are subject to power factor adjustment based upon the maintenance by the customer of an average monthly power factor of 85%, leading or lagging, as measured by integrating meters. When the average monthly power factor is above or below 85%, leading or lagging, the on-peak and off-peak kWh as metered will, for billing purposes, be multiplied by the constant, rounded to the nearest 0.0001, derived from the following formula:

$$\text{Constant} = 0.9510 + \left[0.1275 \left[\frac{\text{RKVAH}}{\text{KWH}} \right]^2 \right]$$

In no event shall the Constant derived from the above formula be greater than 2.0000.

B. Metered Voltage

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss-compensating equipment, the use of formulas to calculate losses, or the application of multipliers to the metered quantities. In such cases, the metered kWh and kW values will be adjusted for billing purposes. If the Company elects to adjust kWh and kW based on multipliers, the adjustment shall be in accordance with the following:

- (1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.
- (2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Furnace Load Provision – Applicable to Standard Service customers only.

A reduced capacity charge, as stated below, shall apply to service for operation of electric furnaces for metal melting or ore reduction, where the demand for such load is separately metered. This provision shall apply only to electric furnace use with combined billing demand of 500 kW or more. The customer must

(Continued on Sheet No. D-33.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF LP
(Large Power)**

(Continued From Sheet No. D-32.00)

provide special circuits in order that the Company may install separate metering for the furnace load. All other provisions of Tariff LP shall apply to the furnace load.

Furnace Demand Charge (\$ per kW)	Power Supply		Delivery	Total
	Capacity	Non-Capacity		
Secondary	6.26	12.83	7.74	26.83
Primary	6.14	12.50	4.88	23.52
Subtransmission	6.09	12.29	0.28	18.66
Transmission	6.04	12.09	.17	18.30

Delayed Payment Charge

A delayed payment charge of 2% of the total net bill shall be added to any bill which is not paid on or before the due date shown thereon as set forth in Rule 460.1614 of the MPSC Rules. The due date shall be 22 days following the date of transmittal.

Applicable Riders

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. D-90.00.

Term of Contract

Contracts under this tariff will be made for an initial period of not less than two years and shall remain in effect thereafter until either party shall give at least one year's written notice to the other of the intention to discontinue service under the terms of this tariff.

A new initial contract period will not be required for existing customers who increase their contract requirements after the original initial period unless new or additional facilities are required. Where new facilities are required, the Company reserves the right to require initial contracts for periods of greater than two years.

The Company may not be required to supply capacity in excess of that contracted for except by mutual agreement.

Notwithstanding any contractual requirement for longer than 90 days' notice to discontinue Standard Service, customers may elect to take service from a qualified Alternate Electric Supplier (AES), pursuant to the Terms and Conditions of Open Access Distribution Service, by providing 90 days' written notice to the Company. If upon completion of such 90-day notice period the customer has not enrolled with a qualified AES, then the customer must continue to take service under the Company's Standard Service for a period of not less than twelve (12) consecutive months.

(Continued on Sheet No. D-34.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF LP
(Large Power)**

(Continued From Sheet No. D-33.00)

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Standard Service, or Items 1, 11, and/or 17 of the Terms and Conditions of Open Access Distribution Service, as applicable.

A customer's plant is considered as one or more buildings that are served by a single electrical distribution system provided and operated by customer. When the size of the customer's load necessitates the delivery of energy to the customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the customer's system irrespective of contrary provisions in the Terms and Conditions of Standard Service, or Items 1, 11, and/or 17 of the Terms and Conditions of Open Access Distribution Service, as applicable.

This tariff is also available to customers having other on-site sources of electric energy supply, who purchase standby or backup electric service from the Company. Where such conditions exist, the customer shall contract for the maximum amount of demand in kW, which the Company might be required to furnish, but not less than 1,500 kW. The Company shall not be obligated to supply demands in excess of that contracted for. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

Standard Service customers with cogeneration and/or small power production facilities shall take service under Rider NMS-1 (Net Metering Service for Customers With Generating Facilities of 20 kW or Less, Rider NMS-2 (Net Metering Service for Customers with Generating Facilities Greater than 20 kW), Tariff COGEN/SPP or by special agreement with the Company.

OAD customers with cogeneration or small power production facilities designed to operate in parallel with the Company's system shall take service by special agreement with the Company.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF MS
(Municipal and School Service)**

This tariff is in the process of elimination and is withdrawn except for the present installations of customers receiving service hereunder at premises serviced prior to October 1, 1976. When new or upgraded facilities are required to maintain service to a Tariff MS customer, the customer shall be removed from Tariff MS and be required to take service under an appropriate general service tariff for which the customer qualifies.

Availability of Service

Available to governmental authorities of municipalities, townships, counties, the State of Michigan, and the United States for the supply of electric energy to public buildings or locations which are supported by public tax levies and to primary and secondary schools .

Monthly Rate (Tariff Codes 543, 544 & 882)

	Power Supply		Delivery	Total
	Capacity	Non-Capacity		
Service Charge (\$)	--	--	25.15	25.15
Energy Charge (¢ per kWh): For all kWh equal to the monthly billing demand (kW) times 250 hours of use	2.626	6.105	--	8.731
For all kWh greater than the monthly billing demand (kW) times 250 hours of use	1.582	6.105	-	7.687
Demand Charge (\$ per kW)	--	--	6.03	6.03

Capacity and Non-Capacity Power Supply and Delivery Charges are applicable to Standard Service customers.

Capacity Power Supply and Delivery Charges only are applicable to Open Access Distribution customers.

Minimum Charge

This tariff is subject to a minimum monthly charge equal to the monthly service charge and all applicable riders.

Monthly Billing Demand

Energy supplied hereunder will be delivered through not more than one single-phase and/or one polyphase meter. Billing demand in kW shall be taken each month as the single highest 15-minute peak as registered during the month by a 15-minute integrating demand meter or, at the Company's option, as the highest registration of a thermal-type demand meter. Where energy is presently delivered through two meters, the monthly billing demand will be taken as the sum of the two demands separately determined. The minimum billing demand shall be 10 kW.

(Continued on Sheet No.D-.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF MS
(Municipal and School Service)**

(Continued From Sheet No. D-.00)

Delayed Payment Charge

A delayed payment charge of 2% of the total net bill shall be added to any bill which is not paid on or before the due date shown thereon as set forth in Rule 460.1614 of the MPSC Rules. The due date shall be 22 days following the date of transmittal.

Applicable Riders

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. D-90.00.

Term of Contract

Notwithstanding any contractual requirement for longer than 90 days' notice to discontinue Standard Service, customers may elect to take service from a qualified Alternate Electric Supplier (AES), pursuant to the Terms and Conditions of Open Access Distribution Service, by providing 90 days' written notice to the Company. If upon completion of such 90-day notice period the customer has not enrolled with a qualified AES, then the customer must continue to take service under the Company's Standard Service for a period of not less than 12 consecutive months.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Standard Service, or Items 1, 11, and/or 17 of the Terms and Conditions of Open Access Distribution Service, as applicable.

Standard Service customers with cogeneration and/or small power production facilities shall take service under Rider NMS-1 (Net Metering Service for Customers With Generating Facilities of 20 kW or Less, Rider NMS-2 (Net Metering Service for Customers with Generating Facilities Greater than 20 kW), Tariff COGEN/SPP or by special agreement with the Company.

OAD customers with cogeneration or small power production facilities designed to operate in parallel with the Company's system shall take service by special agreement with the Company.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF EHS
(Electric Heating Schools)**

This tariff is withdrawn except for the present installations of customers receiving service hereunder at premises served prior to June 10, 1975. When new or upgraded facilities are required to maintain service to a Tariff EHS customer, the customer shall be removed from Tariff EHS and be required to take service under an appropriate general service tariff for which the customer qualifies.

Availability of Service

Available to primary and secondary schools and to college and university buildings, and additions thereto, where the principal energy requirements, including all lighting, heating, cooling, water heating, and cooking, are provided by electric energy.

Monthly Rate (Tariff Code 631 and 881)

	<u>Power Supply</u>		Delivery	Total
	Capacity	Non-Capacity		
Service Charge (\$)	--	--	25.15	25.15
Energy Charge (¢ per kWh): For all kWh equal to the monthly billing demand (kW) times 250 hours of use	3.021	6.665	-	9.686
For all kWh greater than the monthly billing demand (kW) times 250 hours of use	2.326	6.665	-	8.991
Demand Charge (\$ per kW)	--	--	6.50	6.50

Capacity and Non-Capacity Power Supply and Delivery Charges are applicable to Standard Service customers.

Capacity Power Supply and Delivery Charges only are applicable to Open Access Distribution customers.

Minimum Charge

This tariff is subject to a minimum monthly charge equal to the monthly service charge and all applicable riders.

Monthly Billing Demand

Energy supplied hereunder will be delivered through not more than one single-phase and/or one polyphase meter. Billing demand in kW shall be taken each month as the single highest 15-minute peak as registered during the month by a 15-minute integrating demand meter or, at the Company's option, as the highest registration of a thermal-type demand meter. Where energy is presently delivered through two meters, the monthly billing demand will be taken as the sum of the two demands separately determined. The minimum billing demand shall be 10 kW.

Off-Peak Hour Provision – Applicable to Standard Service customers only.

Demand created during the off-peak hours (as set forth below) shall be disregarded for billing purposes provided that the billing demand shall not be less than 60% of the maximum demand created during the billing month.

(Continued on Sheet No. D-42.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF EHS
(Electric Heating Schools)**

(Continued From Sheet No. D-41.00)

For the purpose of this tariff, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as all other hours in the week.

Delayed Payment Charge

A delayed payment charge of 2% of the total net bill shall be added to any bill which is not paid on or before the due date shown thereon as set forth in Rule 460.1614 of the MPSC Rules. The due date shall be 22 days following the date of transmittal.

Applicable Riders

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. D-90.00.

Term of Contract

Notwithstanding any contractual requirement for longer than 90 days' notice to discontinue Standard Service, customers may elect to take service from a qualified Alternate Electric Supplier (AES), pursuant to the Terms and Conditions of Open Access Distribution Service, by providing 90 days' written notice to the Company. If upon completion of such 90-day notice period the customer has not enrolled with a qualified AES, then the customer must continue to take service under the Company's Standard Service for a period of not less than 12 consecutive months.

Special Terms and Conditions

This tariff shall not apply to individual residences.

Customer may elect to receive service for any individual building of a school complex under the terms of this tariff.

This tariff is subject to the Company's Terms and Conditions of Standard Service, or Items 1, 11, and/or 17 of the Terms and Conditions of Open Access Distribution Service, as applicable.

This tariff is also available to customers having other on-site sources of electric energy supply, who purchase standby or backup electric service from the Company. Where such conditions exist, the customer shall contract for the maximum amount of demand in kW, which the Company might be required to furnish, but not less than 100 kW. The Company shall not be obligated to supply demands in excess of that contracted for. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

(Continued on Sheet No. D-43.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF EHS
(Electric Heating Schools)**

(Continued From Sheet No. D-42.00)

Standard Service Customers with cogeneration and/or small power production facilities shall take service under Rider NMS-1 (Net Metering Service for Customers With Generating Facilities of 20 kW or Less, Rider NMS-2 (Net Metering Service for Customers with Generating Facilities Greater than 20 kW), Tariff COGEN/SPP or by special agreement with the Company.

OAD Customers with cogeneration or small power production facilities designed to operate in parallel with the Company's system shall take service by special agreement with the Company.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF IS
(Irrigation Service)**

Availability of Service

Available to customers engaged in agricultural pursuits and desiring secondary voltage service for the irrigation of crops. The customer shall provide the necessary facilities to separately meter the irrigation load. Other general-use load shall be served under the applicable tariff.

Monthly Rate (Tariff Code 213 and 895)

Voltage	Power Supply		Delivery	Total
	Capacity	Non-Capacity		
Secondary				
Energy Charge (¢ per kWh)	5.397	9.649	7.859	22.905

Capacity and Non-Capacity Power Supply and Delivery Charges are applicable to Standard Service customers.

Capacity Power Supply and Delivery Charges only are applicable to Open Access Distribution customers.

Minimum Charge

This tariff is subject to a minimum monthly charge equal to all applicable riders.

Delayed Payment Charge

A delayed payment charge of 2% of the total net bill shall be added to any bill which is not paid on or before the due date shown thereon as set forth in Rule 460.1614 of the MPSC Rules. The due date shall be 22 days following the date of transmittal.

Applicable Riders

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. D-90.00.

Term of Contract

Contracts under this tariff may, at the Company's option, be required for an initial period of not less than one year and shall remain in effect thereafter until either party shall give at least six months' written notice to the other of the intention to discontinue service under the terms of this tariff. Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year.

Continued on Sheet No. D-45.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF IS
(Irrigation Service)**

(Continued From Sheet No. D-44.00)

Notwithstanding any contractual requirement for longer than 90 days' notice to discontinue Standard Service, customers may elect to take service from a qualified Alternate Electric Supplier (AES), pursuant to the Terms and Conditions of Open Access Distribution Service, by providing 90 days' written notice to the Company. If upon completion of such 90-day notice period the customer has not enrolled with a qualified AES, then the customer must continue to take service under the Company's Standard Service for a period of not less than 12 consecutive months.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Standard Service, or Items 1, 11, and/or 17 of the Terms and Conditions of Open Access Distribution Service, as applicable.

Due to the nature of this service, monthly meter readings may not be taken during periods of no consumption or inaccessibility to the meter location due to irrigation operations. In any event, the Company shall obtain a minimum of two meter readings per calendar year.

Standard Service Customers with cogeneration and/or small power production facilities shall take service under Rider NMS-1 (Net Metering Service for Customers With Generating Facilities of 20 kW or Less, Rider NMS-2 (Net Metering Service for Customers with Generating Facilities Greater than 20 kW), Tariff COGEN/SPP or by special agreement with the Company.

OAD Customers with cogeneration or small power production facilities designed to operate in parallel with the Company's system shall take service by special agreement with the Company.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 – ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF OSL
(Outdoor Security Lighting)**

Availability of Service

Available for security lighting to individual customers including community associations, real estate developers, and municipalities. This service is not available for street and highway lighting.

Monthly Rate

For each lamp with luminaire and an upsweep arm not over six feet in length or bracket mounted floodlight, controlled by photoelectric relay, where service is supplied from an existing pole and secondary facilities of Company (a pole which presently serves another function besides supporting a security light), the rates are \$ per lamp per month as follows:

Tariff Code	Lamp Watts	Lumens/Lamp Type	Power Supply		Delivery	Total
			Capacity	Non-Capacity		
		Standard Luminaire				
106 & 911	70	5,800 High Pressure Sodium	0.00	1.40	6.25	7.65
094 & 912	100	9,500 High Pressure Sodium	0.00	1.20	6.70	7.90
113 & 913	150	15,500 High Pressure Sodium	0.00	1.95	7.25	9.20
097 & 914	200	22,000 High Pressure Sodium	0.00	2.50	8.70	11.20
098 & 915	400	50,000 High Pressure Sodium	0.00	4.40	12.70	17.10
132 & 932	132	5,200 Experimental LED	0.00	0.55	7.20	7.75
		Floodlight				
107 & 921	200	22,000 High Pressure Sodium	0.00	2.50	10.40	12.90
109 & 922	400	50,000 High Pressure Sodium	0.00	4.40	13.85	18.25
110 & 925	250	17,000 Metal Halide	0.00	3.10	9.25	12.35
116 & 926	400	28,800 Metal Halide	0.00	4.50	12.65	17.15
		Post-Top				
122 & 928		9,500 HPS on Fiberglass Pole	0.00	1.20	24.24	25.44

Capacity and Non-Capacity Power Supply and Delivery Charges are applicable to Standard Service customers.

Capacity Power Supply and Delivery Charges only are applicable to Open Access Distribution customers.

The above rates are subject to all applicable riders.

Other Equipment

When other new facilities are to be installed by the Company, the customer will, in addition to the above monthly charge, pay in advance the installation cost of such new overhead facilities extending from the nearest or most suitable pole of the Company to the point designated by the customer for the installation of said lamp, except that customer may, for the following facilities only, elect, in lieu of such payment of the installation cost, to pay the following distribution charges:

(Continued on Sheet No. D-47.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U- 18370**

**M.P.S.C. 15 – ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE 18370)**

**TARIFF OSL
(Outdoor Security Lighting)**

(Continued From Sheet No. D-46.00)

30 Foot Wood Pole	\$ 7.00 per month
35 Foot Wood Pole	\$ 8.10 per month
40 Foot Wood Pole	\$ 9.45 per month
Overhead Wire Span Not Over 125 Feet	\$ 3.25 per month
Underground Wire Lateral Not Over 50 Feet (Price includes pole riser and connections)	\$ 6.25 per month

When a customer requests service hereunder requiring wire span lengths in excess of 125 feet, special poles for fixtures or special protection for poles (for example, in parking lots), the customer will be required to make a contribution equal to the additional investment required as a consequence of the special facilities. This includes the cost of underground wire circuits in excess of 50 feet, for which the customer will be required to pay a distribution charge of \$8.10 per foot of excess footage, plus any and all costs required to repair, replace, or push under sidewalks, pavement, or other obstacles.

Security lights supported by poles serving no other function, but which were placed in service under Tariff OL (Outdoor Lighting) may be served under this tariff. In such a case, the following schedule of distribution charges will apply to the wood poles and wire spans:

Overhead Wire Span	\$ 3.25 per span per month
30 or 35 Foot Pole	\$ 7.00 per pole per month

Tariff Code	Discontinued Lamps	Power Supply		Delivery	Total
		Capacity	Non-Capacity		
	Standard Luminaire				
093 & 916	7,000 Mercury Vapor	0.00	2.65	8.95	11.60
096 & 918	11,000 Mercury Vapor	0.00	3.40	6.95	10.35
095 & 919	20,000 Mercury Vapor	0.00	6.20	10.80	17.00
100 & 920	50,000 Mercury Vapor	0.00	16.10	15.55	31.65
	Floodlight				
114 & 923	20,000 Mercury Vapor	0.00	6.20	10.85	17.05
119 & 924	50,000 Mercury Vapor	0.00	16.10	16.00	32.10
	Post Top				
099 & 917	7,000 Mercury Vapor	0.00	2.65	9.00	11.65

Capacity and Non-Capacity Power Supply and Delivery Charges are applicable to Standard Service customers.

Capacity Power Supply and Delivery Charges only are applicable to Open Access Distribution customers.

The above rates are subject to all applicable riders.

(Continued on Sheet No. D-48.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 – ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF OSL
(Outdoor Security Lighting)**

(Continued From Sheet No. D-47.00)

The Energy Policy Act of 2005 requires that mercury vapor lamp ballasts shall not be manufactured or imported after January 1, 2008. To the extent that the Company has the necessary materials, the Company will continue to maintain existing mercury vapor lamp installations in accordance with this Tariff.

Hours of Lighting

All lamps shall burn from one-half hour after sunset until one-half hour before sunrise, every night and all night, or approximately 4,000 hours per annum.

Monthly Kilowatt-hour Usage

The monthly kilowatt-hours for each lamp type applicable to Tariffs OSL, SLC, and ECLS are as follows:

Type of Lamp and Approx. Lumens ¹		Total Watts	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Incandescent														
2,500 Lumens		189	79	67	67	57	51	45	48	55	60	71	75	81
4,000 Lumens		295	124	104	104	89	79	71	76	86	94	111	116	126
Mercury Vapor														
3,400 L 4,400 L	100W	130	55	46	46	39	35	31	33	38	41	49	51	56
7,560 L 8,500 L	175W	216	91	76	76	65	58	52	55	63	69	81	86	92
10,700 L 13,000 L	250W	301	126	106	106	90	81	72	77	88	97	113	119	129
19,100 L 23,000 L	400W	474	199	167	167	142	127	114	121	138	152	178	188	203
45,500 L 63,000 L	1,000W	1,135	477	400	400	340	304	272	291	331	363	427	449	486
High Pressure Sodium														
5,670 L 6,300 L	70W	86	36	30	30	26	23	21	22	25	28	32	34	37
8,550 L 9,500 L	100W	121	51	43	43	36	32	29	31	35	39	45	48	52
14,400 L 16,000 L	150W	176	74	62	62	53	47	42	45	51	57	66	70	75
19,800 L 22,000 L	200W	253	106	89	89	76	68	61	65	74	81	95	100	108
45,000 L 50,000 L	400W	500	210	176	176	150	134	120	128	146	160	188	198	214
Metal Halide														
17,000 L 20,500 L	250W	301	127	106	106	90	81	72	77	88	96	113	119	129
28,800 L 36,000 L	400W	474	199	167	167	142	127	114	121	138	152	178	188	203
LED														
4,800 L	41 W	41	17	14	14	12	11	10	10	12	13	15	16	17
5,000 L Post-Top	45 W	45	19	16	16	14	12	11	12	13	14	17	18	19
5,200 L	57 W	57	24	20	20	17	15	14	15	17	18	22	22	24
14,000 L	139 W	139	59	49	49	42	37	33	35	40	44	52	55	60

(Continued on Sheet No. D-49.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 – ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF OSL
(Outdoor Security Lighting)**

(Continued From Sheet No. D-48.00)

NOTE: For half-night (time clock) lamps multiply consumption by 0.5 or for a 7-hour timer multiply by 0.63875.

¹Lumen output for Mercury Vapor, High Pressure Sodium, and Metal Halide listed in this table as means lumens in the first column and initial lumens in the second column. Lumen rating varies with lamp manufacturer

Ownership of Facilities

All facilities necessary for service including fixtures, controls, poles, transformers, secondaries, lamps, and other appurtenances shall be owned and maintained by the Company. All service and necessary maintenance will be performed only during the regular scheduled working hours of the Company. Burned out lamps will normally be replaced within 48 hours after notification by customer.

Delayed Payment Charge

A delayed payment charge of 2% of the total net bill shall be added to any bill which is not paid on or before the due date shown thereon as set forth in Rule 460.1614 of the MPSC Rules. The due date shall be 22 days following the date of transmittal.

Applicable Riders

Monthly charges computed under this tariff shall be adjusted in accordance with the following Commission-approved rider(s) listed on Sheet No. D-90.00.

Contracts

Contracts under this tariff will ordinarily be made for an initial term of one year for service where lights are installed on existing poles, or not less than five years for service requiring new poles. In the case of customers contracting for four or more lamps apiece, the Company reserves the right to include in the contract such other provisions as it may deem necessary to insure payment of bills throughout the term of the contract.

Notwithstanding any contractual requirement for longer than 90 days' notice to discontinue Standard Service, customers may elect to take service from a qualified Alternate Electric Supplier (AES), pursuant to the Terms and Conditions of Open Access Distribution Service, by providing 90 days' written notice to the Company. If upon completion of such 90-day notice period the customer has not enrolled with a qualified AES, then the customer must continue to take service under the Company's Standard Service for a period of not less than 12 consecutive months.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Standard Service, or Items 1, 11, and/or 17 of the Terms and Conditions of Open Access Distribution Service, as applicable.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF SLS
(Streetlighting Service)**

Availability of Service

This tariff is withdrawn except for existing streetlights serving those municipalities, counties, and other governmental subdivisions in the former St. Joseph Rate Area having contracted for such service under this tariff, Tariff SLN (Streetlighting - New and Rebuilt Systems), or a special contract prior to the first effective date of Tariff ECLS (Energy Conservation Lighting Service) on August 13, 1980.

The Energy Policy Act of 2005 requires the mercury vapor ballasts shall not be manufactured or imported as of January 1, 2008. To the extent that the Company has the necessary materials, the Company will continue to maintain existing mercury vapor lamp installations in accordance with this Tariff.

Monthly Rate (Tariff Code 533 and 900)

Rates are \$ per lamp per month.

Lumens/Lamp Type	Power Supply		Delivery	Total
	Capacity	Non-Capacity		
On Wood Pole With Overhead Circuitry				
7,000 Lumen Mercury Vapor	0.00	2.25	5.80	8.05
20,000 Lumen Mercury Vapor	0.00	4.90	5.85	10.75
On Metallic, Concrete or Fiberglass Poles With Overhead Circuitry				
20,000 Lumen Mercury Vapor	0.00	4.90	8.35	13.25
On Metallic, Concrete or Fiberglass Poles With Underground Circuitry				
7,000 Lumen Mercury Vapor	0.00	2.25	10.80	13.05
20,000 Lumen Mercury Vapor	0.00	4.90	10.85	15.75
50,000 Lumen Mercury Vapor	0.00	11.75	11.00	22.75

Capacity and Non-Capacity Power Supply and Delivery Charges are applicable to Standard Service customers.
Capacity Power Supply and Delivery Charges only are applicable to Open Access Distribution customers.

The above rates are subject to all applicable riders.

(Continued on Sheet No. D-51.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON AND
AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF SLS
(Streetlighting Service)**

(Continued From Sheet No. D-50.00)

Streetlighting Facilities

All facilities necessary for streetlighting service hereunder, including, but not limited to, all poles, fixtures, streetlighting circuits, transformers, lamps, and other necessary facilities, shall be the property of the Company and may be removed if the Company so desires at the termination of any contract for service hereunder. The Company will maintain all such facilities; however, the Company will not be responsible for replacing or rebuilding obsolete, discontinued, decorative, or other facilities which, in the opinion of the Company, are too expensive or unusual to replace or rebuild. In such instances, the customer may, at its own expense, replace or rebuild the facilities or may contract for new service under any applicable tariff.

Hours of Lighting

Streetlighting lamps shall burn from approximately one-half hour after sunset until approximately one-half hour before sunrise, every night, approximately 4,000 hours per annum.

Lamp Outages

All outages which are reported by a proper representative of the customer shall be repaired within two working days. If the lamp is not repaired within two working days, the monthly charge for that unit will be reduced by 1/30 for each day of the outage beyond two working days.

Delayed Payment Charge

A delayed payment charge of 2% of the total net bill shall be added to any bill which is not paid on or before the due date shown thereon as set forth in Rule 460.1614 of the MPSC Rules. Any governmental agency shall be allowed such additional period of time for payment of the net bill as the agency's normal fiscal operations require, not to exceed 30 days.

Applicable Riders

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. D 90.00.

(Continued on Sheet No. D-52.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16- ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF SLS
(Streetlighting Service)**

(Continued From Sheet No. D-51.00)

Relocation and Removal of Lamps

Lamps may be relocated or removed when requested in writing by a proper representative of the Customer, subject, however to the following conditions:

Lamps will be relocated upon payment by the Customer of the estimated cost of doing the work.

Lamps will be removed upon payment by the Customer of the estimated cost of doing the work.

Upon completion of the work, billing for relocation or removal of lamps will be adjusted to reflect actual costs. Charges under this tariff will end when the lamp and/or facilities are removed.

The customer shall pay the ongoing cost of any existing facilities associated with the relocated or removed lamps which must remain in place for the sole purpose of supplying power to other lamps of the Customer. The ongoing cost shall be the cost as specified in Tariff OSL for Other Equipment. For any equipment not specified in Tariff OSL, the charge shall be based upon the Company's actual cost.

The Company will relocate or remove lamps as rapidly as labor conditions permit.

Contracts

Contracts under this tariff will ordinarily be made for an initial term of ten years with self-renewal provisions for successive periods of one year each until either party shall give at least 60 days' notice to the other of the intention to discontinue at the end of the initial term or any yearly period. The Company will have the right to require contracts for periods of longer than ten years.

Notwithstanding any contractual requirement for longer than 90 days' notice to discontinue Standard Service, customers may elect to take service from a qualified Alternate Electric Supplier (AES), pursuant to the Terms and Conditions of Open Access Distribution Service, by providing 90 days' written notice to the Company. If upon completion of such 90-day notice period the customer has not enrolled with a qualified AES, then the customer must continue to take service under the Company's Standard Service for a period of not less than 12 consecutive months.

Special Terms and Conditions.

This tariff is subject to the Company's Terms and Conditions of Standard Service, or Items 1, 11, and/or 17 of the Terms and Conditions of Open Access Distribution Service, as applicable.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF SLC
(Streetlighting - Customer-Owned System)**

Availability of Service

Available to municipalities, counties, and other governmental subdivisions for streetlighting service supplied through streetlighting systems which are owned by the municipality, county, or other governmental subdivision.

This tariff is also available to community associations which have been incorporated as not-for-profit corporations.

Service rendered hereunder is predicated upon the execution by the customer of an agreement specifying the type, number, and location of lamps to be lighted.

The availability of this service may be withheld from extension to otherwise qualifying customers' systems if, in the opinion of the Company, the location or design of such lighting system will create safety hazards or extraordinary difficulties in the performance of maintenance.

The Energy Policy Act of 2005 requires the mercury vapor ballasts shall not be manufactured or imported as of January 1, 2008. To the extent the Company has the necessary materials, the Company will continue to maintain existing mercury vapor lamp installations in accordance with the Tariff.

Monthly Rate (Tariff Code 531 and 901)

Rates are \$ per lamp per month.

Lamp Watts	Lumens/Lamp Type	Power Supply		Delivery	Total
		Capacity	Non-Capacity		
70	5,800 High Pressure Sodium	0.00	0.90	0.95	1.85
100	9,500 High Pressure Sodium	0.00	1.25	1.05	2.30
150	14,400 High Pressure Sodium	0.00	1.85	1.20	3.05
200	22,000 High Pressure Sodium	0.00	2.80	1.35	4.15
400	50,000 High Pressure Sodium	0.00	5.20	1.95	7.15
175	7,000 Mercury Vapor *	0.00	2.25	2.05	4.30
400	20,000 Mercury Vapor *	0.00	4.95	2.45	7.40
1,000	50,000 Mercury Vapor *	0.00	11.80	3.55	15.35
80	4,800 Lumen Roadway LED	0.00	0.45	1.25	1.65
116	5,000 Lumen LED Post Top	0.00	0.45	1.25	1.70
142	14,000 Lumen Roadway I LED	0.00	1.45	2.00	3.45

*Rates apply to existing luminaries only and are not available for new business.

Capacity and Non-Capacity Power Supply and Delivery Charges are applicable to Standard Service customers. Capacity Power Supply and Delivery Charges only are applicable to Open Access Distribution customers. The above rates are subject to all applicable riders.

(Continued on Sheet No. D-54.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF SLC
(Streetlighting - Customer-Owned System)**

(Continued From Sheet No. D-53.00)

Pole Contact Provision

When the customer chooses to own all components of the existing streetlight system on joint use distribution facilities, except for the poles and conductor, a distribution charge of \$0.47 per lamp per month will be added to the monthly lamp rate.

This rate applies only where the Company has existing facilities in place. If such existing facilities must be modified or rebuilt to accommodate the safe installation and maintenance of customer-owned streetlight equipment, then the customer shall reimburse the Company for the total cost of such modifications or rebuilt facilities. The Company reserves the right to relocate or remove existing distribution facilities. When such relocation or removal occurs, the customer will have the option to either purchase the poles and conductors to maintain service to the streetlight system or to abandon such facilities. All installations or removal of customer-owned equipment on Company-owned poles will be made by the Company and the customer shall reimburse the Company for the cost of such installations or removals.

The Company will not extend existing distribution facilities or build new distribution facilities for the sole purpose of accommodating a customer-owned streetlight system unless the customer agrees to reimburse the Company for the cost of such new facilities.

Hours of Lighting

Lamps shall burn from approximately one-half hour after sunset until approximately one-half hour before sunrise, every night, approximately 4,000 hours per annum.

Lamp Outages

All outages which are reported by a proper representative of the customer shall be repaired within two working days. If the lamp is not repaired within two working days, the monthly charge for that unit will be reduced by 1/30 for each day of the outage beyond two working days.

Service To Be Rendered

For completely customer-owned systems, the Company will furnish electrical energy for the operation of lamps and will maintain same by renewals of lamps and cleaning and replacement of glassware. Other maintenance, repair, and replacement will be the responsibility of the customer.

For customer-owned systems on Company poles, all maintenance of customer-owned streetlight equipment shall be performed by Company personnel. The Company will furnish energy for operation of lamps and maintain same by renewals of lamps and cleaning and replacement of glassware. The Company will not be responsible to provide replacement glassware for discontinued, decorative, or certain other luminaires which, in the opinion of the Company, are too expensive or unusual to warrant such replacement service. The Company may, at its option, provide service to such luminaires, but the customer will be required to provide at

(Continued on Sheet No. D-55.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF SLC
(Streetlighting - Customer-Owned System)**

(Continued From Sheet No. D-54.00)

no cost to the Company the replacement glassware. All other maintenance on the customer's streetlight system shall be performed by the Company at the customer's expense.

Customers who perform all maintenance, repair, and replacement of lamps and fixtures (except for photo control) will receive a monthly distribution credit of \$1.34 per lamp.

Delayed Payment Charge

A delayed payment charge of 2% of the total net bill shall be added to any bill which is not paid on or before the due date shown thereon as set forth in Rule 460.1614 of the MPSC Rules. The due date shall be 22 days following the date of transmittal. Any governmental agency shall be allowed such additional period of time for payment of the net bill as the agency's normal fiscal operations require, not to exceed 30 days.

Applicable Riders

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. D 90.00

Contracts

Contracts under this tariff will ordinarily be made for an initial term of one year with self-renewal provisions for successive periods of one year each until either party shall give at least 60 days' notice to the other of the intention to discontinue at the end of the initial term or any yearly period. The Company will have the right to require contracts for periods of longer than one year.

Notwithstanding any contractual requirement for longer than 90 days' notice to discontinue Standard Service, customers may elect to take service from a qualified Alternate Electric Supplier (AES), pursuant to the Terms and Conditions of Open Access Distribution Service, by providing 90 days' written notice to the Company. If upon completion of such 90-day notice period the customer has not enrolled with a qualified AES, then the customer must continue to take service under the Company's Standard Service for a period of not less than 12 consecutive months.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Standard Service, or Items 1, 11, and/or 17 of the Terms and Conditions of Open Access Distribution Service, as applicable.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF ECLS
(Energy Conservation Lighting Service)**

Availability of Service

Available for streetlighting service to municipalities, counties, and other governmental subdivisions. This rate is applicable for service that is supplied through new or rebuilt streetlighting systems, including extension of streetlighting systems to additional locations where service is requested by the customer. Service rendered hereunder is predicated upon the execution by the customer of an agreement specifying the type, minimum number, and location of lamps to be supplied and lighted.

The Energy Policy Act of 2005 requires that mercury vapor ballasts shall not be manufactured or imported after January 1, 2008. To the extent that the Company has the necessary materials, the Company will continue to maintain existing mercury vapor lamp installations in accordance with this Tariff.

Monthly Rate (Tariff Code 530 and 902)

Rates are \$ per lamp per month.

Lamp Watts	Lumens/Lamp Type	Power Supply		Delivery	Total
		Capacity	Non-Capacity		
	On Wood Pole With Overhead Circuitry				
70	5,800 High Pressure Sodium	0.00	0.90	3.95	4.85
100	9,500 High Pressure Sodium	0.00	1.25	4.15	5.40
150	15,500 High Pressure Sodium	0.00	1.85	4.30	6.15
200	22,000 High Pressure Sodium	0.00	2.65	4.60	7.25
400	50,000 High Pressure Sodium	0.00	5.20	5.35	10.55
100	3,500 Mercury Vapor*	0.00	1.35	5.80	7.15
175	7,000 Mercury Vapor *	0.00	2.25	5.80	8.05
250	11,000 Mercury Vapor*	0.00	3.15	5.80	8.95
400	20,000 Mercury Vapor *	0.00	4.90	5.85	10.75
1,000	50,000 Mercury Vapor *	0.00	11.75	6.00	17.75
41	4,800 Lumen Roadway LED	0.00	0.45	16.50	16.95
139	14,000 Lumen Roadway LED	0.00	1.45	18.80	20.25
	On Metallic, Concrete or Fiberglass Pole With Overhead Circuitry*				
70	5,800 High Pressure Sodium	0.00	0.90	7.45	8.35
100	9,500 High Pressure Sodium	0.00	1.25	7.60	8.85
150	15,500 High Pressure Sodium	0.00	1.80	7.80	9.60
200	22,000 High Pressure Sodium	0.00	2.65	8.15	10.80

(Continued on Sheet No. D-57.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF ECLS
(Energy Conservation Lighting Service)**

(Continued from Sheet No. D-56.00)

400	50,000 High Pressure Sodium	0.00	5.20	8.80	14.00
175	7,000 Mercury Vapor	0.00	2.25	8.30	10.55
250	11,000 Mercury Vapor	0.00	3.10	8.25	11.35
400	20,000 Mercury Vapor	0.00	4.95	8.35	13.30
1,000	50,000 Mercury Vapor	0.00	11.80	8.50	20.30
Lamp Watts	Lumens/Lamp Type	Power Supply		Delivery	Total
		Capacity	Non-Capacity		
	On Metallic, Concrete or Fiberglass Pole With Underground Circuitry*				
70	5,800 High Pressure Sodium	0.00	0.90	7.45	8.35
100	9,500 High Pressure Sodium	0.00	1.30	7.60	8.90
200	22,000 High Pressure Sodium	0.00	2.65	8.15	10.80
400	50,000 High Pressure Sodium	0.00	5.20	8.80	14.00
175	7,000 Mercury Vapor	0.00	2.25	10.85	13.10
400	20,000 Mercury Vapor	0.00	4.90	10.85	15.75
1,000	50,000 Mercury Vapor	0.00	11.80	11.00	22.80
	Post-top Lamp on Fiberglass Pole With Underground Circuitry				
100	9,500 High Pressure Sodium	0.00	1.25	6.10	7.35
175	7,000 Mercury Vapor *	0.00	2.25	2.05	4.30
116	5,000 Lumen Post-top LED	0.00	0.45	24.00	24.45

*Rates apply to existing luminaires only and are not available for new business.

Capacity and Non-Capacity Power Supply and Delivery Charges are applicable to Standard Service customers.

Capacity Power Supply and Delivery Charges only are applicable to Open Access Distribution customers.

The above rates are subject to all applicable riders.

The customer will be required to make a contribution in aid of construction calculated in accordance with the formula set forth below if the customer requests the installation of any facility other than a standard Company luminaire and an upsweep arm not over 10 feet in length installed on a pole described in the above rate.

(Continued on Sheet No. D-58.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF ECLS
(Energy Conservation Lighting Service)**

(Continued From Sheet No. D-57.00)

The contribution in aid of construction will equal the difference between estimated cost of the streetlighting system requested by the customer and the estimated cost of a streetlighting system using a lamp controlled by a photoelectric relay, a standard Company luminaire, and an upsweep arm not over 10 feet in length installed on a wood pole with overhead circuitry of a span length not to exceed 150 feet. When underground facilities are requested by the customer, the estimated installed distribution cost of the underground circuit will be \$8.10 per foot plus any and all costs required to repair, replace, or push under sidewalks, pavements, or other obstacles. A customer paying a contribution in aid of construction will pay the above monthly rate for wood poles with overhead circuitry.

Streetlighting Facilities

All facilities necessary for streetlighting service hereunder, including but not limited to, all poles, fixtures, streetlighting circuits, transformers, lamps, and other necessary facilities, shall be the property of the Company and may be removed if the Company so desires at the termination of any contract. The Company will maintain all such facilities.

Hours of Lighting

Lamps shall burn from approximately one-half hour after sunset until approximately one-half hour before sunrise, every night, approximately 4,000 hours per annum.

Lamp Outages

All outages that are reported by a proper representative of the customer shall be repaired within two working days. If the lamp is not repaired within two working days, the monthly charge for that unit will be reduced by 1/30 for each day of the outage beyond two working days.

Delayed Payment Charge

A delayed payment charge of 2% of the total net bill shall be added to any bill which is not paid on or before the due date shown thereon as set forth in Rule 460.1614 of the MPSC Rules. The due date shall be 22 days following the date of transmittal. Any governmental agency shall be allowed such additional period of time for payment of the net bill as the agency's normal fiscal operations require, not to exceed 30 days.

Applicable Riders

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. D-90.00.

(Continued on Sheet No. D-59.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF ECLS
(Energy Conservation Lighting Service)**

(Continued From Sheet No. D-58.00)

Relocation and Removal of Lamps

Lamps may be relocated or removed when requested in writing by a proper representative of the Customer, subject, however to the following conditions:

Lamps will be relocated upon payment by the Customer of the estimated cost of doing the work.

Lamps will be removed upon payment by the Customer of the estimated cost of doing the work.

Upon completion of the work, billing for relocation or removal of lamps will be adjusted to reflect actual costs. Charges under this tariff will end when the lamp and/or facilities are removed.

The customer shall pay the ongoing cost of any existing facilities associated with the relocated or removed lamps which must remain in place for the sole purpose of supplying power to other lamps of the Customer. The ongoing cost shall be the cost as specified in Tariff OSL for Other Equipment. For any equipment not specified in Tariff OSL, the charge shall be based upon the Company's actual cost.

The Company will relocate or remove lamps as rapidly as labor conditions permit.

Contracts

Contracts under this tariff will ordinarily be made for an initial term of one year with self-renewal provisions for successive periods of one year each until either party shall give at least 60 days' notice to the other of the intention to discontinue at the end of the initial term or any yearly period. The Company will have the right to require contracts for periods of longer than one year.

Notwithstanding any contractual requirement for longer than 90 days' notice to discontinue Standard Service, customers may elect to take service from a qualified Alternate Electric Supplier (AES), pursuant to the Terms and Conditions of Open Access Distribution Service, by providing 90 days' written notice to the Company. If upon completion of such 90-day notice period the customer has not enrolled with a qualified AES, then the customer must continue to take service under the Company's Standard Service for a period of not less than 12 consecutive months.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Standard Service, or Items 1, 11, and/or 17 of the Terms and Conditions of Open Access Distribution Service, as applicable.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF SLCM
(Streetlighting - Customer-Owned System - Metered)**

Availability of Service

Available to municipalities, counties, and other governmental subdivisions for lighting on streets and highways (including illuminated signs) and in parks and other such public areas. This tariff is also available for lighting systems serving outdoor recreational facilities such as baseball fields and football stadiums.

This tariff is also available to community associations which have been incorporated as not-for-profit corporations.

Monthly Rate (Tariff Codes 733, 734, 903 and 904)

	Power Supply		Delivery	Total
	Capacity	Non-Capacity		
Service Charge (\$):				
Single Phase 120/240 volts	--	--	7.77	7.77
Single Phase 240/480 volts	--	--	16.58	16.58
Energy Charge (¢ per kWh)	0.00	3.118	2.447	5.565

Capacity and Non-Capacity Power Supply and Delivery Charges are applicable to Standard Service customers.

Capacity Power Supply and Delivery Charges only are applicable to Open Access Distribution customers.

Hours of Service

This service is available only during the hours each day between sunset and sunrise. Daytime use of energy under this rate is strictly forbidden except for the sole purpose of testing and maintaining the lighting system.

Delayed Payment Charge

A delayed payment charge of 2% of the total net bill shall be added to any bill which is not paid on or before the due date shown thereon as set forth in Rule 460.1614 of the MPSC Rules. The due date shall be 22 days following the date of transmittal. Any governmental agency shall be allowed such additional period of time for payment of the net bill as the agency's normal fiscal operations require, not to exceed 30 days.

Applicable Riders

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. D-90.00.

(Continued on Sheet No. D-61.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF SLCM
(Streetlighting - Customer-Owned System - Metered)**

(Continued From Sheet No. D-60.00)

Contracts

A written contract may, at the Company's option, be required for each customer. Customers requiring service in multiple locations may combine services under one agreement.

Standard Service Contracts will ordinarily be made for an initial term of one year with self-renewal provisions for successive terms of one year each until either party shall give at least 60 days' notice to the other of the intention to discontinue at the end of any term. The contract will specify the service location(s) and the approximate connected load in kilowatts. A separate invoice will be rendered each billing period for each meter location regardless of the number of contracts.

Notwithstanding any contractual requirement for longer than 90 days' notice to discontinue Standard Service, customers may elect to take service from a qualified Alternate Electric Supplier (AES), pursuant to the Terms and Conditions of Open Access Distribution Service, by providing 90 days' written notice to the Company. If upon completion of such 90-day notice period the customer has not enrolled with a qualified AES, then the customer must continue to take service under the Company's Standard Service for a period of not less than 12 consecutive months.

Special Terms and Conditions.

This tariff is subject to the Company's Terms and Conditions of Standard Service, or Items 1, 11, and/or 17 of the Terms and Conditions of Open Access Distribution Service, as applicable.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF COGEN/SPP
(Cogeneration and/or Small Power Production Service)**

Availability of Service

This schedule is available to Standard Service customers with cogeneration and/or small power production (COGEN/SPP) facilities that qualify under Section 210 of the Public Utilities Regulatory Policies Act of 1978, have a total design capacity of 100 KW or less, and who take Standard Service from the Company. Such facilities shall be designed to operate properly in parallel with the Company's system without adversely affecting the operation of equipment and services of the Company and its customers, and without presenting safety hazards to the Company and customer personnel.

The customer has the following options under this schedule, which will affect the determination of energy and capacity and the monthly metering charges:

(1) Option 1

The customer does not sell any energy or capacity to the Company and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

(2) Option 2

The customer sells to the Company the energy and average capacity produced by the customer's qualifying COGEN/SPP facilities in excess of the customer's total load and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

(3) Option 3

The customer sells to the Company the total energy and average capacity produced by the customer's qualifying COGEN/SPP facilities while simultaneously purchasing from the Company its total load requirements, as determined by appropriate meters located at one delivery point.

Billing under this schedule shall consist of charges for delivery of electrical energy and capacity from the Company to the customer to supply the customer's net or total load according to the rate schedule appropriate for the customer, except as modified herein, plus charges to cover additional costs due to COGEN/SPP facilities, as specified herein, less credits for excess or total electrical energy and capacity produced by the customer's qualifying COGEN/SPP facilities as specified herein.

(Continued on Sheet No. D-63.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF COGEN/SPP
(Cogeneration and/or Small Power Production Service)**

(Continued From Sheet No. 62.00)

Measurement of Energy and Determination of Capacity

Energy and capacity supplied by the Company to the customer and/or produced by the customer's qualifying COGEN/SPP facilities shall be determined by appropriate meters located at one delivery point. Such meters shall be capable of determining energy, and billing demand where applicable, from the Company to the customer to supply the customer's net or total load as required under the rate schedule appropriate for such deliveries. The excess or total energy and average capacity produced by the customer's qualifying COGEN/SPP facilities shall be determined by means of meters other than those used to determine the net or total energy and capacity requirements of the customer's load. At the option of the customer, such meters may be capable of registering produced excess or total energy and average capacity separately during the on-peak and off-peak periods.

Under Option 3, when metering potential for COGEN/SPP facilities is the same as the Company's delivery potential, the customer shall, at his option, either route the COGEN/SPP totalized output leads through the metering point, or make available at the metering point for the use of the Company and as specified by the Company metering current leads that will enable the Company to measure adequately the total electrical energy and average capacity produced by the qualifying COGEN/SPP facilities, as well as to measure the electrical energy consumption and capacity requirements of the customer's total load. When metering potential for COGEN/SPP facilities is different from the Company's delivery potential, metering requirements and charges shall be determined specifically for each case.

Monthly Charges for Delivery from the Company to the Customer

(1) Supplemental Service

Available to the customer to supplement its COGEN/SPP source of power supply which will enable either or both sources of supply to be utilized for all or any part of the customer's total requirements.

Charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the rate schedule appropriate for the customer. Option 1 and Option 2 customers with COGEN/SPP facilities having a total design capacity of more than 10 kW shall be served under demand-metered rate schedules.

(2) Back-up and Maintenance Service

Option 1 and Option 2 customers with COGEN/SPP facilities having a total design capacity of more than 10 kW shall be required to purchase backup service to replace energy from COGEN/SPP facilities during maintenance and unscheduled outages of its COGEN/SPP facilities. Contracts for such service shall be executed on a special contract form for a minimum term of one year.

(Continued on Sheet No. D-64.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-64.00

**TARIFF COGEN/SPP
(Cogeneration and/or Small Power Production Service)**

(Continued From Sheet No. D-63.00)

Option 3 customers purchasing their total energy requirements from the Company will not be considered as taking backup service. Customers having cogeneration and/or small power production facilities that operate intermittently during all months (i.e. wind or solar) such that the customer's monthly billing demands under the demand-metered rate schedule will be based upon the customer's maximum monthly demand which will occur at a time when the cogeneration and/or small power production facility is not in operation will also not be considered as taking backup service.

The backup capacity in kilowatts shall be initially established by mutual agreement for electrical capacity sufficient to meet the maximum backup requirements which the Company is expected to supply. Whenever the backup capacity so established is exceeded by the creation of a greater actual maximum demand, excluding firm load regularly supplied by the Company, then such greater demand becomes the new backup capacity.

The monthly charge per kW of backup capacity paid by customers served under demand-metered rate schedules shall be as follows:

Power Supply	Delivery Service	Total
\$0.82	\$1.64	\$2.46

Whenever backup and maintenance capacity is used and the customer notifies the Company in writing prior to the meter reading date, the backup contract capacity shall be subtracted from the total metered demand during the period specified by the customer for billing demand purposes. After 1,900 hours of use during the contract year, the total metered demand shall be used as the billing demand each month until a new contract year is established.

In lieu of the above monthly charge, customers may instead elect to have the monthly billing demand under the demand-metered rate schedules determined each month as the highest of the monthly billing demand for the current and previous two billing periods.

Charges for Special Facilities

There shall be additional distribution charges to cover the cost of special metering, safety equipment, and other local facilities installed by the Company due to COGEN/SPP facilities as follows:

(1) **Monthly Metering Charge**

The additional monthly distribution charge for special metering facilities shall be as follows:

(Continued on Sheet No. D-65.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)

TARIFF COGEN/SPP
(Cogeneration and/or Small Power Production Service)

(Continued From Sheet No. D-64.00)

(a) Option 1

Where the customer does not sell electricity to the Company, the Company will install a detent to prevent reverse meter rotation and will include its cost in the local facilities charge, thus not requiring a separate additional monthly metering charge.

(b) Option 2(a)

Where standard energy meters are used to measure the excess energy and average capacity purchased by the Company:

	Single Phase	Polyphase
Primary Service or Secondary Service Over 200 Amps	\$ 12.67	\$ 12.67
Secondary Service of 200 Amps or Less	\$ 1.23	\$ 7.45

(c) Option 2(b)

Where time-of-day (TOD) energy meters are used to measure the excess energy and average capacity purchased by the Company:

	Single Phase	Polyphase
Primary Service or Secondary Service Over 200 Amps	\$ 12.96	\$ 12.96
Secondary Service of 200 Amps or Less	\$ 4.70	\$ 7.74

(Continued on Sheet No. D-66.00)

ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER

ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF COGEN/SPP
(Cogeneration and/or Small Power Production Service)**

(Continued From Sheet No. D-65.00)

(d) Option 3(a)

Where standard energy meters are used to measure the total energy and average capacity produced by the customer's COGEN/SPP facilities:

	Single Phase	Polyphase
Primary Service or Secondary Service Over 200 Amps Using Metering Current Leads	\$ 12.67	\$ 12.67
Secondary Service of 200 Amps or Less Using Metering Current Leads	\$ 12.67	\$ 12.67
Secondary Service of 200 Amps or Less Using Totalized Output Leads	\$ 1.23	\$ 7.45

(e) Option 3(b)

Where time-of-day (TOD) energy meters are used to measure the total energy and average capacity produced by the customer's COGEN/SPP facilities:

	Single Phase	Polyphase
Primary Service or Secondary Service Over 200 Amps Using Metering Current Leads	\$ 12.96	\$ 12.96
Secondary Service of 200 Amps or Less Using Metering Current Leads	\$ 12.96	\$ 12.96
Secondary Service of 200 Amps or Less Using Totalized Output Leads	\$ 1.23	\$ 7.74

(Continued on Sheet No. D-67.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF COGEN/SPP
(Cogeneration and/or Small Power Production Service)**

(Continued From Sheet No. D-66.00)

(2) Local Facilities Charge

Additional charges to cover the cost of safety equipment and other local facilities installed by the Company shall be determined by the Company for each case and collected from the customer. The customer shall make a one-time payment for such charges upon completion of the required additional facilities, or, at the customer's option, twelve consecutive equal monthly payments reflecting an annual interest charge equal to the maximum rate permitted by law not to exceed the prime rate in effect at the first billing for such installments.

Monthly Credits or Payments for Excess or Total Electrical Energy and Capacity Produced by COGEN/SPP Facilities

(1) Energy Credit

The following generation credits or payments from the Company to the customer shall apply for the excess electrical energy delivered to the Company or the total electrical energy produced by the customer's qualifying COGEN/SPP facilities:

- (a) If standard energy meters are used, 3.24¢/kWh for all energy delivered or produced during the billing period or, at the option of the customer, the monthly average, real-time, PJM wholesale market locational marginal price at a Company pricing node mutually agreed upon by the Company and the customer.
- (b) If TOD meters are used, 3.91¢/kWh for all energy delivered and produced during the on-peak period, and 2.63¢/kWh for all energy delivered or produced during the off-peak period or at the option of the customer, PJM wholesale market real-time locational marginal on-peak and off-peak prices at a Company pricing node mutually agreed upon by the Company and customer.

(2) Capacity Credit

If the customer contracts to deliver or produce a specified excess or total average capacity during the monthly billing period (monthly contract capacity), or a specified excess or total average capacity during the on-peak monthly billing period (on-peak contract capacity), and/or a specified excess or total average capacity during the off-peak monthly billing period (off-peak contract capacity), and if the contract term is equal to or greater than two years, then the following generation capacity credits or payments from the Company to the customer shall apply:

- A. If standard energy meters are used, \$ 0.00/kW/month, times the lowest of:

- (1) monthly contract capacity, or

(Continued on Sheet No. D-68.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF COGEN/SPP
(Cogeneration and/or Small Power Production Service)**

(Continued From Sheet No. D-67.00)

- (2) current month metered average capacity, i.e., kWh delivered to the Company or produced by COGEN/SPP facilities divided by 730, or
 - (3) lowest average capacity metered during previous two months if less than monthly contract capacity.
- B. If TOD energy meters are used, \$ 0.00/kW/month, times the lowest of:
- (1) On-peak contract capacity, or
 - (2) Current month on-peak metered average capacity, i.e., on-peak kWh delivered to the Company or produced by COGEN/SPP facilities divided by 347, or
 - (3) Lowest on-peak average capacity metered during previous two months, if less than on-peak contract capacity.

The above energy and capacity credit rates are subject to revision from time to time as approved by the Commission.

On-Peak and Off-Peak Periods

The on-peak period shall be defined as starting at 7 a.m. and ending at 11 p.m., local time, Monday through Friday.

The off-peak period shall be defined as starting at 11 p.m. and ending at 7 a.m., local time, for all weekdays, Monday through Friday, and all hours of Saturday and Sunday.

Charges for Cancellation or Non-Performance of Contract

If the customer should, for a period in excess of six months, discontinue or substantially reduce for any reason the operation of cogeneration and/or small power production facilities that were the basis for the monthly contract capacity, or the on-peak contract capacity, and/or the off-peak contract capacity, the customer shall make a one-time generation payment to the Company, determined as Six times the applicable monthly capacity credit rate then in effect, times the applicable contract capacity or reduction thereof.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF CATV
(Pole Attachment Rental - Cable Television)**

Availability of Service

Available to any person, firm, corporation, partnership, or cooperatively organized association ("Attaching Party or Attachee"), other than a utility or a municipality, who has obtained under law any necessary public or private authorization and permission to construct and maintain attachments such as wire, cable, facility, or other apparatus on Company poles so long as those attachments do not interfere, obstruct, or delay the service and operation of the Company or create a safety hazard.

Distribution Charges and Rates

In addition to the pole application fee set forth below, Attachee agrees to pay Company an initial contact fee and an annual attachment charge at the rates specified in this tariff for the use of each of Company's poles, any portion of which is occupied by or reserved at Attachee's request for the attachment of Attachee's facilities at any time during the rental period.

Basic Charges and Rates	
1. Pole Application Fee:	\$50.00 plus \$10.00 per pole
The purpose of the application fee is to recover the Company's expense to conduct the make-ready survey required to determine the feasibility of the requested attachment(s). The application fee is due at the time application is made.	
2. Initial Contact Fee:	\$1.25 per pole
To cover the cost to the Company not separately accounted for in processing the application for each initial contact, but no such initial contact fee shall be required if the customer has previously paid an initial contact fee with respect to such pole location.	
3. Annual Attachment Charge:	\$3.74 per pole per year
Attachee agrees to pay Company the annual rate for the use of each of Company's poles, any portion of which is occupied by, or reserved at Attachee's request for the attachment of Attachee at any time during the rental period.	
Other Charges	
1. All charges for inspections, engineering, rearrangements, or removals of Attachee's facilities from Company's poles and other work performed for Attachee shall be based on the full cost and expense to Company in performing such work. The charges shall be determined in accordance with the normal and customary methods used by the Company in determining such costs.	
2. The charges for replacement of poles necessary to facilitate Attachee's attachments and requirements shall be net costs as determined by the normal and customary methods used by the Company.	

(Continued on Sheet No. D-70.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF CATV
(Pole Attachment Rental - Cable Television)**

(Continued From Sheet No. D-69.00)

Payment and Billing

Invoices shall be rendered by Company, in advance, on an annual basis on or about July 1 based upon the attachments in place as of the preceding June 1. For any pole occupied or reserved at any time during the rental year, the full attachment charge will be billed on the subsequent annual billing. Payment will be due 45 days from the date the invoice is issued by the Company.

Invoices to Attachees with fewer than 20 pole attachments may be rendered on a multi-year basis so as to effect a minimum billing invoice of \$30.

On all amounts not paid when due, an additional charge of 1.5% per month shall be assessed.

Agreements

Pole attachments shall be allowed only upon signing by Company and the Attachee of a written agreement making reference to this tariff.

Period of Agreement

Agreements executed with reference to this tariff shall continue until cancelled by either party on not less than 60 days' prior written notice to the other. No such termination, however, shall reduce or eliminate the obligation of the Attachee to make payments of any amounts due to Company for any service covered by this tariff, and shall not waive charges for any attachment until it is removed from the pole to which it is attached.

Special Terms and Conditions

The terms and conditions of service shall be as set forth within the Company's standard agreement and this tariff.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF CS-IRP
(CONTRACT SERVICE – INTERRUPTIBLE POWER)**

Availability of Service.

Available to customers having interruptible demands of 1,000 kW or greater, who contract for Standard Service under one of the Company's interruptible service options. The Company reserves the right to limit the total contract capacity for all customers served under this tariff to 50,000 kW.

Conditions of Service.

The Company will offer eligible customers the opportunity to receive service under options which provide for mandatory (capacity) interruptions and discretionary (energy) interruptions pursuant to a contract agreed to by the Company and the Customer.

For mandatory (capacity) interruptions, the minimum interruption requirement shall be the minimum required under the PJM Interconnection, LLC (PJM) Emergency Load Response Program for capacity purposes, or any successor thereto. The minimum compensation for mandatory (capacity) interruptions shall be 80% of the applicable PJM Reliability Pricing Model ("RPM") clearing price.

Upon receipt of a request from the Customer for interruptible service, the Company will provide the Customer with a written offer containing the rates and related terms and conditions of service under which such service will be provided by the Company. If the parties reach an agreement based upon the offer provided to the Customer by the Company, such written contract will be filed with the Commission. The contract shall provide full disclosure of all rates, terms and conditions of service under this tariff, and any and all agreements related thereto, subject to the designation of the terms and conditions of the contract as confidential, as set forth herein.

The Company reserves the right to test and verify the customer's ability to curtail.

Rate.

Charges for service under this schedule will be set forth in the written agreement between the Company and the Customer and will reflect a discount from the firm service rates otherwise available to the Customer.

Contract Terms.

The length of the agreement and the terms and conditions of service will be stated in the agreement between the Company and the Customer.

(Continued on Sheet No. D-72.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**TARIFF CS-IRP
(CONTRACT SERVICE – INTERRUPTIBLE POWER)**

(Continued From Sheet No. D-71.00)

Confidentiality.

All terms and conditions of any written contract under this schedule shall be protected from disclosure as confidential, proprietary trade secrets if either the Customer or the Company requests a Commission determination of confidentiality, and the Commission finds that the party requesting such protection has shown good cause for protecting the terms and conditions of the contract.

Terms and Conditions.

Except as otherwise provided in the written agreement, the Company's Terms and Conditions of Standard Service shall apply to service under this tariff.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**RIDER AFS
(Alternate Feed Service)**

Availability of Service.

Standard Alternate Feed Service (AFS) is a premium service providing a redundant distribution service provided through a redundant distribution line and distribution station transformer, with automatic or manual switch-over and recovery, which provides increased reliability for distribution service. Rider AFS applies to those customers requesting new or upgraded AFS after the effective date of this rider. Rider AFS also applies to existing customers that desire to maintain redundant service when the Company must make expenditures in order to continue providing such service.

Rider AFS is available to customers who request a primary voltage alternate feed and who normally take service under Tariffs G.S., L.G.S., L.P., M.S. or W.S.S. for their basic service requirements, provided that the Company has adequate capacity in existing distribution facilities, as determined by the Company, or if changes can be made to make capacity available. AFS provided under this rider may not be available at all times, including emergency situations.

System Impact Study Charge.

The Company shall charge the customer for the actual cost incurred by the Company to conduct a system impact study for each site reviewed. The study will consist of, but is not limited to, the following: (1) identification of customer load requirements, (2) identification of the potential facilities needed to provide the AFS, (3) determination of the impact of AFS loading on all electrical facilities under review, (4) evaluation of the impact of the AFS on system protection and coordination issues including the review of the transfer switch, (5) evaluation of the impact of the AFS request on system reliability indices and power quality, (6) development of cost estimates for any required system improvements or enhancements required by the AFS, and (7) documentation of the results of the study. The Company will provide to the customer an estimate of charges for this study.

Equipment and Installation Charge.

The customer shall pay, in advance of construction, a nonrefundable amount for all equipment and installation costs for all dedicated and/or local facilities provided by the Company required to furnish either a new or upgraded AFS. The payment shall be grossed-up for federal and state income taxes, assessment fees and utility receipts taxes. The customer will not acquire any title in said facilities by reason of such payment. The equipment and installation charge shall be determined by the Company and shall include, but not be limited to, the following: (1) all costs associated with the AFS dedicated and/or local facilities provided by the Company and (2) any costs or modifications to the customer's basic service facilities.

The customer is responsible for all costs associated with providing and maintaining phone service for use with metering to notify the Company of a transfer of service to the AFS or return to basic service.

(Continued on Sheet No. D-74.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED FEBRUARY 15, 2012
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**RIDER AFS
(Alternate Feed Service)**

(Continued From Sheet No. D-73.00)

Transfer Switch Provisions.

In the event the customer receives basic service at primary voltage, the customer shall install, own, maintain, test, inspect, operate and replace the transfer switch. Customer-owned switches are required to be at primary voltage and must meet the Company's engineering, operational and maintenance specifications. The Company reserves the right to inspect the customer-owned switches periodically and to disconnect the AFS for adverse impacts on reliability or safety.

Existing AFS customers, who receive basic service at primary voltage and are served via a Company-owned transfer switch and control module, may elect for the Company to continue ownership of the transfer switch. When the Company-owned transfer switch and/or control module requires replacement or repair, and the customer desires to continue the AFS, the customer shall pay the Company the total cost to replace such equipment which shall be grossed up for federal and state income taxes, assessment fees and utility receipts taxes. In addition, the customer shall pay a monthly rate of \$15.98 for the Company to annually test the transfer switch / control module and the customer shall reimburse the Company for the actual costs involved in maintaining the Company-owned transfer switch and control module.

In the event a customer receives basic service at secondary voltage and requests AFS, the Company will provide the AFS at primary voltage. The Company will install, own, maintain, test, inspect and operate the transfer switch and control module. The customer shall pay the Company a nonrefundable amount for all costs associated with the transfer switch installation. The payment shall be grossed-up for federal and state income taxes, assessment fees and utility receipts taxes. In addition, the customer is required to pay the monthly rate for testing and ongoing maintenance costs defined above. When the Company-owned transfer switch and/or control module requires replacement, and the customer desires to continue the AFS, customer shall pay the Company the total cost to replace such equipment which shall be grossed up for federal and state income taxes, assessment fees and utility receipts taxes.

After a transfer of service to the AFS, a customer utilizing a manual or semi-automatic transfer switch shall return to the basic service within one (1) week or as mutually agreed to by the Company and customer. In the event system constraints require a transfer to be expedited, the Company will endeavor to provide as much advance notice as possible to the customer. However, the customer shall accomplish the transfer back to the basic service within ten minutes if notified by the Company of system constraints. In the event the customer fails to return to basic service within 12 hours, or as mutually agreed to by the Company and customer, or within ten minutes of notification of system constraints, the Company reserves the right to immediately disconnect the customer's load from the AFS source. If the customer does not return to the basic service as agreed to, or as requested by the Company, the Company may also provide 30 days' notice to terminate the AFS agreement with the customer.

The customer shall make a request to the Company for approval three days in advance for any planned switching.

(Continued on Sheet No. D-75.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**RIDER AFS
(Alternate Feed Service)**

(Continued From Sheet No. D-74.00)

Monthly AFS Capacity Reservation Demand Charge.

Monthly AFS charges will be in addition to all monthly basic service charges paid by the customer under the applicable tariff.

The Monthly AFS Capacity Reservation Demand Charge for the reservation of distribution station and primary lines is \$4.44 per kW.

AFS Capacity Reservation.

The customer shall reserve a specific amount of AFS capacity equal to, or less than, the customer's normal maximum requirements, but in no event shall the customer's AFS capacity reservation under this rider exceed the capacity reservation for the customer's basic service under the appropriate tariff. The Company shall not be required to supply AFS capacity in excess of that reserved except by mutual agreement.

If the customer plans to increase the AFS demand at anytime in the future, the customer shall promptly notify the Company of such additional demand requirements. The customer's AFS capacity reservation and billing will be adjusted accordingly. The customer will pay the Company the actual costs of any and all additional dedicated and/or local facilities required to provide AFS in advance of construction and pursuant to an AFS construction agreement. If customer exceeds the agreed upon AFS capacity reservation, the Company reserves the right to disconnect the AFS. If the customer's AFS metered demand exceeds the agreed upon AFS capacity reservation, which jeopardizes company facilities or the electrical service to other customers, the Company reserves the right to disconnect the AFS immediately. If the Company agrees to allow the customer to continue AFS, the customer will be required to sign a new AFS agreement reflecting the new AFS capacity reservation. In addition, the customer will promptly notify the Company regarding any reduction in the AFS capacity reservation.

The customer may reserve partial-load AFS capacity, which shall be less than the customer's full requirements for basic service subject to the conditions in this provision. Prior to the customer receiving partial-load AFS capacity, the customer shall be required to demonstrate or provide evidence to the Company that they have installed demand-controlling equipment that is capable of curtailing load when a switch has been made from the basic service to the AFS. The Company reserves the right to test and verify the customer's ability to curtail load to meet the agreed upon partial-load AFS capacity reservation.

Determination of Billing Demand.

Full-Load Requirement:

For customers requesting AFS equal to their load requirement for basic service, the AFS billing demand shall be taken each month as the single-highest 15-minute integrated peak as registered during the month by a demand meter or indicator, but the monthly AFS billing demand so established shall in no event be less than the greater of (a) the customer's AFS capacity reservation, or (b) the customer's highest previously established monthly billing demand on the AFS during the past 11 months, or (c) the customer's basic service

(Continued on Sheet No. D-76.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**RIDER AFS
(Alternate Feed Service)**

(Continued From Sheet No. D-75.00)

capacity reservation, or (d) the customer's highest previously established monthly billing demand on the basic service during the past 11 months.

Partial-Load Requirement:

For customers requesting partial-load AFS capacity reservation that is less than the customer's full requirements for basic service, the AFS billing demand shall be taken each month as the single-highest 15-minute integrated peak on the AFS as registered during the month by a demand meter or indicator, but the monthly AFS billing demand so established shall in no event be less than the greater of (a) the customer's AFS capacity reservation, or (b) the customer's highest previously established monthly metered demand on the partial-load AFS during the past 11 months.

Delayed Payment Charge

A delayed payment charge of 2% of the total net bill shall be added to any bill which is not paid on or before the due date shown thereon as set forth in Rule 460.1614 of the MPSC Rules. The due date shall be 22 days following the date of transmittal.

Terms of Contract.

The AFS agreement under this rider will be made for a period of not less than one year and shall remain in effect thereafter until either party shall give at least six months' written notice to the other of the intention to discontinue service under the terms of this rider.

Disconnection of AFS under this rider due to reliability or safety concerns associated with customer-owned transfer switches will not relieve the customer of payments required hereunder for the duration of the agreement term.

Special Terms and Conditions.

This rider is subject to the Company's Terms and Conditions of Standard Service.

Upon receipt of a request from the customer for non-standard AFS (AFS which includes unique service characteristics different from standard AFS), the Company will provide the customer with a written estimate of all costs, including system impact study costs, and any applicable unique terms and conditions of service related to the provision of the non-standard AFS. An AFS agreement will be filed with the Commission under the 30-day filing procedures. The AFS agreement shall provide full disclosure of all rates, terms and conditions of service under this rider, and any and all agreements related thereto.

The Company will have sole responsibility for determining the basic service circuit and the AFS circuit.

The Company assumes no liability should the AFS circuit, transfer switch, or other equipment required to provide AFS fail to operate as designed, is unsatisfactory, or is not available for any reason.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-77.00

ECONOMIC DEVELOPMENT RIDER

Availability of Service.

In order to encourage economic development in the Company's service area, limited-term credits for incremental billing demands described herein are offered to qualifying new and existing retail customers who make application for service under this Rider prior to January 1, 2020.

Service under this Rider is intended for customers whose operations, by their nature, will promote sustained economic development based on plant and facilities investment and job creation. This Rider is available to commercial and industrial customers taking service from the Company under Tariffs G.S., L.G.S., L.G.S.-TOD or L.P. who meet the following requirements:

- (1) A new customer must have a billing demand of 300 kW or more. An existing customer must increase billing demand by 300 kW or more over the maximum billing demand during the 12 months prior to the date of the application by the customer for service under this Rider (Base Maximum Billing Demand). The Base Maximum Billing Demand for new customers is zero (0).
- (2) The customer must apply for and receive economic development assistance from State or local government or other public agency.
- (3) The customer must demonstrate to the Company's satisfaction that, absent the availability of this Rider, the qualifying new or increased demand would be located outside of the Company's service territory or would not be placed in service due to poor operating economics.

Availability is limited to customers on a first-come, first-served basis for loads aggregating 50 MW.

Terms and Conditions.

- (1) To receive service under this Rider, the customer shall make written application to the Company with sufficient information contained therein to determine the customer's eligibility for service.
- (2) For new customers, billing demands for which credits will be applicable under this Rider shall be for service at a new service location and not merely the result of a change of ownership. However, if a change in ownership occurs after the customer enters into a Contract for service under this Rider, the successor customer may be allowed to fulfill the balance of the Contract under this Rider. Relocation of the delivery point of the Company's service does not qualify as a new service location.

(Continued To Sheet D-78.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-78.00

ECONOMIC DEVELOPMENT RIDER

(Continued From Sheet No. D-77.00)

- (3) For existing customers, billing demands for which credits will be applicable under this Rider shall be the result of an increase in business activity and not merely the result of resumption of normal operations following a force majeure, strike, equipment failure, renovation or refurbishment, or other such abnormal operating condition. In the event that such an occurrence has taken place during the 12-month period prior to the date of the application by the customer for service under this Rider, the monthly billing demands during the 12-month period shall be adjusted as appropriate to eliminate the effects of such occurrence in the determination of the Base Maximum Billing Demand.
- (4) All billing credits offered under this Rider shall terminate no later than December 31, 2025.
- (5) The existing local facilities of the Company must be deemed adequate, in the judgment of the Company, to supply the new or expanded electrical capacity requirements of the customer. If construction of new or expanded local facilities by the Company are required, the customer may be required to make a contribution-in-aid of construction for the installed cost of such facilities pursuant to the provisions of Item 12, B and / or 13, C of the Company's Terms and Conditions of Standard Service.

Determination of Monthly Billing Credit.

The qualifying incremental billing demand shall be determined as the amount by which the billing demand, as determined according to the applicable tariff for the current billing period, exceeds the Base Maximum Billing Demand, multiplied by the current billing period load factor percentage. Such adjusted incremental billing demand shall be considered to be zero, however, unless it is at least 300 kW.

The monthly billing credit under this Rider shall be the product of the qualifying incremental billing demand as calculated above and the applicable Billing Credit rate.

The monthly billing credit shall not reduce the customer's bill below the monthly minimum charge as specified in the applicable tariff.

Selection of Credit Option.

Customers meeting all availability and terms and conditions above shall contract for service for a period of eight (8) years under one of the three Credit Options shown below. The Credit Option chosen by the customer shall be specified in the contract for service under this Rider.

(Continued To Sheet D-79.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**I.U.R.C. NO. 16
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-79.00

ECONOMIC DEVELOPMENT RIDER

(Continued From Sheet No. D-78.00)

<u>Credit Options</u>	<u>Billing Months in Contract Terms</u>	<u>Billing Credit per \$ per kW</u>
1 - Inclining	1 st through 12 th	\$7.80
	13 th through 24 th	\$10.20
	25 th through 36 th	\$12.00
	37 th through 48 th	\$13.80
	49 th through 60 th	\$16.20
2 - Levelized	1 st through 12 th	\$12.00
	13 th through 24 th	\$12.00
	25 th through 36 th	\$12.00
	37 th through 48 th	\$12.00
	49 th through 60 th	\$12.00
3 - Declining	1 st through 12 th	\$16.20
	13 th through 24 th	\$13.80
	25 th through 36 th	\$12.00
	37 th through 48 th	\$10.20
	49 th through 60 th	\$7.80

The appropriate Billing Credit rate based upon the customer-selected Credit Option shall be applicable over a period of 60 consecutive billing months beginning with the first such month following the end of the start-up period. The start-up period shall commence with the effective date of the contract for service under this Rider and shall terminate by mutual agreement between the Company and the customer.

The start-up period shall not exceed 12 months. At the sole discretion of the Company, the start-up period may be extended up to 12 additional months.

Terms of Contract.

A contract for service under this Rider and for service under the appropriate tariff, shall be executed by the customer and the Company for the time period which includes the start-up period and the minimum eight-year period immediately following the end of the start-up period with the monthly Billing Credits being available for a maximum period of five (5) years. The contract shall specify the Base Maximum Billing Demand, the anticipated total demand, the Credit Option and related provisions to be applicable under this Rider, and the effective date for the contract.

(Continued To Sheet D-80.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**I.U.R.C. NO. 16
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-80.00

ECONOMIC DEVELOPMENT RIDER

(Continued From Sheet No. D-79.00)

The customer may discontinue service under this Rider before the end of the contract term only by reimbursing the Company for any Billing Credits received under this Rider according to the following schedule:

Years 1 to 5-	100%
Years 6 to 8-	2.5% per each billing period remaining under the terms of the contract

Special Terms and Conditions.

Except as otherwise provided in this Rider, written agreements shall remain subject to all of the provisions of the appropriate tariff. This Rider is subject to the Company's Terms and Conditions of Service.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16- ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-81.00

RIDER NMS-1

(Net Metering Service for Customer's With Generating Facilities of 20 kW or Less)

Availability of Service

Available for Net Metering Service to customers with qualifying renewable energy source generation facilities designed to operate in parallel with the Company's system. Customers served under this rider must also take Standard Service from the Company under the otherwise applicable tariff.

The total rated generating capacity of all net metering customers served under this rider shall be limited to one half of one percent (0.5%) of the Company's previous year's peak demand in kW. Service under this rider shall be available to customers on a first come, first served basis.

Conditions of Service

- (1) For purposes of this rider, a qualifying net metering facility is an electrical generating facility that complies with all of the following requirements:
- (a) As defined in MCL 460.1011(i), utilizes a renewable energy resource that naturally replenishes over a human, not a geological, time frame and that is ultimately derived from solar power, water power, or wind power. Renewable energy resource does not include petroleum, nuclear, natural gas, or coal. A renewable energy resource comes from the sun or from thermal inertia of the earth and minimizes the output of toxic material in the conversion of the energy and includes, but is not limited to, all of the following:
 - i. Biomass
 - ii. Solar and solar thermal energy
 - iii. Wind energy
 - iv. Kinetic energy of moving water, including the following:
 - 1. Waves, tides or currents
 - 2. Water released through a dam
 - v. Geothermal energy
 - vi. Municipal solid waste
 - vii. Landfill gas produced by municipal solid waste.
 - (b) Has a total rated capacity of 20 kW or less.
 - (c) Is located on the customer's premises.
 - (d) Is intended primarily to offset all or part of the customer's own electrical load requirements.
 - (e) Is designed and installed to operate in parallel with the Company's system without adversely affecting the operation of equipment and service of the Company and its customers and without presenting safety hazards to Company and customer personnel.

(Continued on Sheet No. D-82.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16- ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-82.00

RIDER NMS-1

(Net Metering Service for Customer's With Generating Facilities of 20 kW or Less)

(Continued from Sheet No. D-81.00)

A customer using biomass blended with fossil fuel as their renewable energy source must submit proof to the Company substantiating the percentage of fossil fuel blend either by (1) separately metering the fossil fuel or (2) providing other documentation that will allow the Company to correctly apply a generation credit to the output associated with the customer's renewable fuel only.

- (2) The customer's generation system shall be sized not to exceed the customer's electric needs. At the customer's option, the generation capacity shall be determined by the aggregate nameplate capacity of the generator or by an estimate of the expected annual kWh output of the generator. At the customer's option, the customer's annual electricity needs shall be determined by one of the following methods: (1) the customer's annual energy usage, measured in kWh, during the previous twelve month period; (2) for a customer with metered demand data available, the maximum integrated hourly demand measured in kW during the previous twelve month period; or (3) in cases where no data, incomplete data or incorrect data for the customer's previous twelve month energy usage exists, or the customer is making changes on-site that will affect the customer's usage, the Company and the customer shall mutually agree on a method to determine the customer's annual electric needs.
- (3) A customer seeking to interconnect an eligible net metering facility to the Company's system must submit to the Company's designated personnel a completed Interconnection Application, including any required application fees. The Company's net metering application fee is \$25 and its interconnection application fee is \$75. The requirements for interconnecting customer electric generating equipment with the Company's facilities are contained in the Commission's Electric Interconnection and Net Metering Standards Rules and the Company's technical requirements for interconnection. The Company will provide copies of all applicable forms and documents to customers upon request.
- (4) An interconnection agreement between the Company and the eligible net metering customer must be executed before the net metering facility may be interconnected with the Company's system.

Metering

The Company may determine the customer's net usage using the customer's existing meter if it is capable of reverse registration or may, at the Company's expense, install a single meter with separate registers measuring power flow in each direction. If the Company uses the customer's existing meter, the Company shall test and calibrate the meter to assure accuracy in both directions. If the customer's meter is not capable of reverse registration and if meter upgrades or modifications are required, the Company shall provide a meter or meters capable of measuring the flow of energy in both directions to the customer at the Company's cost. Only the incremental cost above that for meter(s) provided by the Company to similarly situated nongenerating customers shall be paid by the eligible customer. A generator meter will be supplied to the customer, at the customer's request, at the Company's cost.

The Company may, with the customer's permission and at its own expense, install one or more additional meters to monitor the flow of electricity.

(Continued on Sheet No. D-83.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16- ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

RIDER NMS-1

(Net Metering Service for Customer's With Generating Facilities of 20 kW or Less)

(Continued from Sheet No. D-82.00)

Monthly Charges

Monthly charges for energy, and demand where applicable, to serve the customer shall be determined according to the Company's standard service tariff under which the customer would otherwise be served, absent the customer's electric generating facility.

Monthly charges for energy shall be determined under the customer's standard service tariff and shall be based on the net energy delivered by the Company to the customer, calculated by subtracting the energy, if any, delivered by the customer to the Company from the energy delivered by the Company to the customer.

If the customer's net monthly billing under the standard service tariff is negative during the billing period, credit for the negative net billing shall be at the customer's full retail rate and shall appear on the customer's next monthly bill. Any credit not used to offset current charges shall be carried forward for use in subsequent billing periods. Upon termination of service from the Company, any remaining credit amount shall be refunded to the customer.

Special Terms and Conditions

This rider is subject to the Company's Terms and Conditions of Standard Service and all provisions of the tariff under which the customer takes service. This rider is also subject to provisions of the Company's technical requirements for interconnection.

The Company's net metering program shall be open for customer enrollments for a period of at least ten years from the original effective date of this rider. A participating customer may terminate their participation in this program at any time.

An eligible electric generator shall own any renewable energy credits granted for electricity generated under the net metering program. The Company may purchase or trade renewable energy certificates from a net metering customer if agreed to by the customer.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16- ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-84.00

RIDER NMS-2

(Net Metering Service for Customer's With Generating Facilities Greater than 20 kW)

Availability of Service

Available for Net Metering Service to customers with qualifying renewable energy source generation facilities designed to operate in parallel with the Company's system. Customers served under this rider must also take Standard Service from the Company under the otherwise applicable tariff.

The total rated generating capacity of all net metering customers served under this rider shall be limited to not more than one quarter of one percent (0.25%) of the Company's previous year's peak demand in kW for customers with a system capable of generating more than 20 kW but not more than 150 kW and not more than one quarter of one percent (0.25%) for customers with a system capable of generating more than 150 kW. Service under this rider shall be available to customers on a first come, first served basis.

Conditions of Service

- (1) For purposes of this rider, a qualifying net metering facility is an electrical generating facility that complies with all of the following requirements:
- (a) As defined in MCL 460.1011(i), utilizes a renewable energy resource that naturally replenishes over a human, not a geological, time frame and that is ultimately derived from solar power, water power, or wind power. Renewable energy resource does not include petroleum, nuclear, natural gas, or coal. A renewable energy resource comes from the sun or from thermal inertia of the earth and minimizes the output of toxic material in the conversion of the energy and includes, but is not limited to, all of the following:
 - i. Biomass
 - ii. Solar and solar thermal energy
 - iii. Wind energy
 - iv. Kinetic energy of moving water, including the following:
 - 1. Waves, tides or currents
 - 2. Water released through a dam
 - v. Geothermal energy
 - vi. Municipal solid waste
 - vii. Landfill gas produced by municipal solid waste.
 - (b) Has a total rated capacity of greater than 20 kW but not more than 150 kW of aggregate generation at a single site for a renewable energy system and not more than 550 kW of aggregate generation at a single site for a methane digester.
 - (c) Is located on the customer's premises.
 - (d) Is intended primarily to offset all or part of the customer's own electrical load requirements.

(Continued on Sheet No. D-85.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16- ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-85.00

RIDER NMS-2

(Net Metering Service for Customer's With Generating Facilities Greater than 20 kW)

(Continued from Sheet No. D-84.00)

- (e) Is designed and installed to operate in parallel with the Company's system without adversely affecting the operation of equipment and service of the Company and its customers and without presenting safety hazards to Company and customer personnel.

A customer using biomass blended with fossil fuel as their renewable energy source must submit proof to the Company substantiating the percentage of fossil fuel blend either by (1) separately metering the fossil fuel or (2) providing other documentation that will allow the Company to correctly apply a generation credit to the output associated with the customer's renewable fuel only.

- (2) The customer's generation system shall be sized not to exceed the customer's electric needs. At the customer's option, the generation capacity shall be determined by the aggregate nameplate capacity of the generator or by an estimate of the expected annual kWh output of the generator. At the customer's option, the customer's annual electricity needs shall be determined by one of the following methods: (1) the customer's annual energy usage, measured in kWh, during the previous twelve month period; (2) for a customer with metered demand data available, the maximum integrated hourly demand measured in kW during the previous twelve month period; or (3) in cases where no data, incomplete data or incorrect data for the customer's previous twelve month energy usage exists, or the customer is making changes on-site that will affect the customer's usage, the Company and the customer shall mutually agree on a method to determine the customer's annual electric needs.
- (3) A customer seeking to interconnect an eligible net metering facility to the Company's system must submit to the Company's designated personnel a completed Interconnection Application, including any required application fees. The Company's net metering application fee is \$25 and its interconnection application fee is \$75. The requirements for interconnecting customer electric generating equipment with the Company's facilities are contained in the Commission's Electric Interconnection and Net Metering Standards Rules and the Company's technical requirements for interconnection. The Company will provide copies of all applicable forms and documents to customers upon request.
- (4) An interconnection agreement between the Company and the eligible net metering customer must be executed before the net metering facility may be interconnected with the Company's system.

Metering

The Company may determine the customer's net usage using the customer's existing meter if it is capable of reverse registration or may, at the Company's expense, install a single meter with separate registers measuring power flow in each direction. If the Company uses the customer's existing meter, the Company shall test and calibrate the meter to assure accuracy in both directions. If the customer's meter is not capable of reverse registration and if meter upgrades or modifications are required, the Company shall provide a meter or meters capable of measuring the flow of energy in both directions to the customer at the Company's cost. For customers with a generation system capable of generating more than 20 kW and up to 150 kW, only the

(Continued on Sheet No. D-86.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16- ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

RIDER NMS-2

(Net Metering Service for Customer's With Generating Facilities Greater than 20 kW)

(Continued from Sheet No. D-85.00)

incremental cost above that for meter(s) provided by the Company to similarly situated nongenerating customers shall be paid by the eligible customer. Customers with a generation system capable of generating more than 150 kW shall be responsible for the Company's full cost of providing any necessary additional metering.

For customers served under this rider, the Company shall install and utilize a generation meter to measure the output of the customer's generator. For customers with generation systems capable of generating 150 kW or less, the cost of the meter shall be considered a cost of operating the Company's net metering program and shall be supplied by the Company at no additional cost to the customer. Customers with generation systems capable of generating more than 150 kW shall be responsible for the Company's full cost of providing such additional metering.

The Company may, with the customer's permission and at its own expense, install one or more additional meters to monitor the flow of electricity.

Monthly Charges

Monthly charges for energy, and demand where applicable, to serve the customer shall be determined according to the Company's standard service tariff under which the customer would otherwise be served, absent the customer's electric generating facility. Monthly transmission and distribution charges for energy shall be determined under the customer's standard service tariff and shall be computed based on the energy delivered by the Company to the customer without reduction for the energy, if any, delivered by the customer to the Company.

Monthly generation charges for energy shall be determined under the customer's standard service tariff and shall be based on the net energy delivered by the Company to the customer, calculated by subtracting the energy, if any, delivered by the customer to the Company from the energy delivered by the Company to the customer.

If the customer's net monthly generation charge billing under the standard service tariff is negative during the billing period, the negative net generation billing shall not be used to reduce the customer's current monthly bill for transmission and distribution service. Instead, the negative net generation billing amount shall appear on the customer's next bill and shall be allowed to accumulate as a \$ credit to offset generation billing in the next billing period. Unused generation credits, if any, will be carried over from month to month and applied to generation billing in subsequent billing months. Generation credits shall not be used to reduce charges for transmission and distribution service. Upon termination of service from the Company, any remaining credit amount shall be refunded to the customer.

Standby Charges

Customers with a generation system capable of generating more than 150 kW shall pay standby costs.

(Continued on Sheet No. D-87.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16- ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

RIDER NMS-2

(Net Metering Service for Customer's With Generating Facilities Greater than 20 kW)

(Continued from Sheet No. D-86.00)

Standby charges for net metering customers on an energy rate schedule shall equal the retail distribution charge applied to the imputed customer usage during the billing period. The imputed customer usage is calculated as the sum of the metered on-site generation and the net of the bidirectional flow of power across the customer interconnection during the billing period. The Commission shall establish standby charges for net metering customers on demand-based rate schedules that provide an equivalent contribution to Company system costs. Standby charges shall not be applied to customers with systems capable of generating 150 kW or less.

Special Terms and Conditions

This rider is subject to the Company's Terms and Conditions of Standard Service and all provisions of the tariff under which the customer takes service. This rider is also subject to provisions of the Company's technical requirements for interconnection.

The Company's net metering program shall be open for customer enrollments for a period of at least ten years from the original effective date of this rider. A participating customer may terminate their participation in this program at any time.

An eligible electric generator shall own any renewable energy credits granted for electricity generated under the net metering program. The Company may purchase or trade renewable energy certificates from a net metering customer if agreed to by the customer.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**RIDER ROS
(RESALE OF SERVICE)**

Availability of Service

Available to general service customers who take Standard Service from the Company under Tariffs GS, , LGS, or LP and who are currently engaged in Resale of Service (ROS).

Electricity supplied to a customer is for exclusive use on the premises to which it is delivered by the Company. Customers desiring to resell electric service must secure authority from the Company which will be evidenced by a rider attached to the contract for service. Resale of service is available only for customers currently reselling as of April 1, 2006 and is closed to new service or expanded service for resale.

If the reselling customer elects to take service under the Company's Open Access Distribution Service Tariffs, the ultimate user (residential, commercial or industrial customer) shall be served and charged for such service under the Open Access Distribution Service Tariff in the Company's rate schedule available for similar services under like conditions.

The reselling customer shall provide notice to ultimate users of the decision to obtain electric service pursuant to the Open Access Distribution Service Tariff and that as a result, the ultimate user's generation and transmission charges are no longer regulated by the Michigan Public Service Commission.

Multiple Occupancy Buildings

The owner or operator of an office building, apartment building, or shopping center with at least thirty ultimate users (or less at the option of the Company) whose combined requirements regularly exceed 20,000 kilowatt hours per month, may purchase electric energy from the Company for resale to the ultimate users on the condition that service to each ultimate user shall be separately metered, and that the ultimate users shall be charged for such service the current rate of the Company for similar service under like conditions.

No customer may charge any ultimate user more for resold electric service purchased from the Company than the ultimate user would be charged by the Company if served directly. If this requirement is violated, service under this rider may be terminated by the Company. The renting of premises with the cost of electric service included in the rental is held not to be a resale of service. The Company does not furnish nor maintain meters for the resale of energy by customers.

Mobile Home Parks

Mobile home park operators may purchase electric energy from the Company for resale to ultimate users, provided that service to each ultimate user buying energy shall be separately metered and billed no more for resold electric service purchased from the Company than the ultimate user would be charged by the Company if served directly.

(Continued on Sheet No. D-89.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

**RIDER ROS
(RESALE OF SERVICE)**

(Continued From Sheet No. D-88.00)

A mobile home park operator shall provide the distribution system in the park and meters acceptable to the Company suitably protected from the weather.

If a mobile home park operator resells energy without complying with the above provisions, service under this rider may be terminated by the Company.

Term of Contract

The customer may take service under any applicable filed tariff listed above but the customer will be required to sign a rider modifying the contract form prescribed for the applicable filed tariff.

A service contract shall provide that each ultimate user's billing shall be audited once every nine (9) to fifteen (15) months. At the option of the reselling customer, the audit will be conducted either by the Company or by an independent auditing firm, approved by the Company. The reselling customer will be assessed a reasonable fee for an audit conducted by the Company. Where the audit is conducted by an independent auditing firm, a certified copy of the results of such audit shall be immediately submitted to the Company in a form approved by the Company.

The service contract shall also provide that the reselling customer will be responsible for the testing of meters used for resale at the time of initially taking service under this Rider and at least once every three (3) years thereafter, and the accuracy of such meters shall be maintained within the limits as prescribed in Michigan Public Service Commission Order No. U-6400. Meters shall only be tested by the Company for a reasonable fee or by outside testing services or laboratories approved by the Company with a certified copy of all testing results immediately submitted to the Company.

A record of each meter, including testing results, shall be kept by the reselling customer during use of the meter and for an additional period of one year thereafter. When requested, the reselling customer shall submit certified copies of testing service or laboratory results to the Company or the Michigan Public Service Commission.

The reselling customer shall supply each ultimate user with an electrical system adequate to meet the needs of the ultimate user with respect to the nature of service, voltage level, and other conditions of service.

If a reselling customer fails to meet the obligations under this rider, the Company shall immediately notify the Michigan Public Service Commission Staff. If, after review with the reselling customer, the problem is not resolved, the Company will discontinue electric service until such time as the problem is resolved. The Company shall not incur any liability as the result of this discontinuance of electric service.

Notwithstanding Rules 460.3901 (1) through (4), a deposit may be required from Rider ROS customers in an amount not to exceed six times the peak season monthly bill for service under this Rider.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16- ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

APPLICABLE POWER SUPPLY AND DELIVERY CHARGE SURCHARGES AND RIDERS

Commission-approved surcharges and riders applicable to Standard Service customers only:

Power Supply Charges Applicable to Standard Service Customers	Sheet No.
Power Supply Cost Recovery Factor	D-91.00
Rate Realignment Surcharge/Credit	D-93.00
Renewable Energy Surcharge	D-96.00

Commission-approved surcharges and riders applicable to Standard Service and Open Access Distribution Service customers:

Delivery Charges Applicable to Standard Service and Open Access Distribution Service customers	Sheet No.
Energy Optimization Surcharge	D-94.00
Nuclear Decommissioning Surcharge	D-95.00
Net Lost Revenue Tracker Surcharge	D-97.00
Low-Income Energy Assistance Fund Surcharge	D-98.00

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. 18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-91.00

POWER SUPPLY COST RECOVERY FACTOR

This clause permits the monthly adjustment of rates for power supply to allow recovery of the booked costs, including transportation costs, reclamation costs, and disposal and reprocessing costs, of fuel burned for electric generation, the booked costs of purchased and net interchange power transactions and the cost of transmission service incurred under reasonable and prudent policies and practices. All rates for standard Michigan retail electric service, unless otherwise provided in the applicable rate schedule, shall include a Power Supply Cost Recovery factor.

For purposes of this clause, the following definitions apply:

"Power supply cost recovery factor" means that element of the rates to be charged for electric service to reflect power supply costs incurred and made pursuant to a power supply cost recovery clause incorporated in the rates or rate schedule.

"Power supply cost recovery plan" means a filing made at least annually describing the expected sources of electric power supply and changes over a future 12-month period specified by the Commission and requesting for each of those 12 months a specific power supply cost recovery factor.

"Power supply costs" means those elements of allowable costs of fuel, purchased and net interchanged power costs, and transmission costs as determined by the Commission to be included in the calculation of the power supply cost recovery factor.

"Cost of power" means those elements of costs of fuel and purchased and net interchanged power costs as determined by the Commission to be recovered in base rates pursuant to a general rate proceeding but which are not allowable in the calculation of the monthly power supply cost recovery factor.

The Power Supply Cost Recovery factor shall, in accordance with the hearing procedures adopted by the Michigan Public Service Commission, consist of 0.01046 mills per kWh for each full .01 mill per kWh of power supply costs, rounded to the nearest .01 mills per kWh, less an amount of 37.71 mills per kWh representing power supply costs included in base rates.

The power supply cost recovery factor to be applied to the Company's Michigan retail customers' monthly kilowatt-hour usage represents the power supply costs as established by Commission order pursuant to a power supply and cost review hearing conducted by the Commission. The power supply and cost review will be conducted not less than once a year for the purpose of evaluating the power supply cost recovery plan filed by the Company and to authorize an appropriate power supply cost recovery factor. Contemporaneously with its power supply cost recovery plan, the Company will file a five-year forecast of the power supply requirements of its customers, its anticipated sources of supply, and projections of power supply costs.

(Continued on Sheet No. D-92.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED
ON AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16 - ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

POWER SUPPLY COST RECOVERY FACTOR
(Continued from Sheet No. D-91.00)

Not more than 45 days following the last day of each billing month in which a power supply cost recovery factor has been applied to customers' bills, the Company shall file with the Commission a detailed statement for that month of the revenues recorded pursuant to the power supply cost recovery factor, the allowance for cost of power included in the base rates established in the latest Commission order for the Company, and the cost of power supply.

Not less than once a year and not later than 90 days after the end of the 12-month period covered by the Company's most recently authorized power supply cost recovery plan, a power supply cost reconciliation proceeding will be commenced to reconcile the revenues recorded pursuant to the power supply cost recovery factor and the allowance for cost of power included in the base rates as established by the Commission under the Company's most recent power supply cost recovery plan, among other things. The Company shall be required to refund to customers, or to credit to customers' bills any net amount, plus interest, determined to have been recovered which is in excess of the amounts properly expensed by the Company for power supply. The Company shall recover from customers any net amount, plus interest, by which the amount determined to have been recovered over the period covered was less than the amount determined to have been properly expensed by the Company for power supply.

Maximum allowable Power Supply Cost Recovery Factors approved by the Commission:

(1)	(2)	(3)	(4)
Billing Month	Total PSCR Costs (Mills/kWh)	PSCR Costs In Base Rates (Mills/kWh)	PSCR Factor Charge/(Credit) (Mills/kWh)
			(Col. 2 - Col. 3)
Jan. – Dec 2015	29.76	23.77	5.99
Jan. – Dec 2016	32.66	23.77	8.89
Jan. – Dec 2017	34.27	23.77	10.50

Should the Company apply a lesser factor than the above, or if the factor is later revised pursuant to Commission Orders or 1982 PA 304, the Company will notify the Commission if necessary and file a revision to the above list.

Actual Power Supply Cost Recovery factors billed pursuant to 1982 PA 304, Section 6j(9):

(1)	(2)	(3)	(4)
Billing Month	Total PSCR Costs (Mills/kWh)	PSCR Costs In Base Rates (Mills/kWh)	PSCR Factor Charge/(Credit) (Mills/kWh)
			(Col. 2 - Col. 3)
Jan. – Dec 2015	29.76	23.77	5.99
Jan. – Dec 2016	32.66	23.77	8.89
Jan. – Dec 2017	34.27	23.77	10.50

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED
ON AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16- ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINALSHEET NO. D-93.00

RATE REALIGNMENT SURCHARGE/CREDIT

All customer bills subject to the provisions of this surcharge, including any bills rendered under special contract, shall be adjusted by the Rate Realignment Surcharge/Credit charge per kWh as follows:

Tariff	Year 1
	(¢/kWh)
RS, RS-TOD, RS-OPES/PEV, RS-SC, and RS-TOD2	0.0458
GS, GS-TOD and GS-TOD 2	0.0433
LGS	0.0303
LP and CS-IRP	0.0252
MS	0.0396
WSS	0.0298
EHS	(1.5364)
IS	(10.3552)
OSL	0.1010
SLS, SLC, ECLS and SLCM	0.0596

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16- ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-94.00

**SURCHARGE RIDER EO
(ENERGY OPTIMIZATION SURCHARGE RIDER)**

Energy Optimization surcharges allow for the recovery of costs of implementing and conducting an approved energy optimization plan.

Energy Optimization surcharges shall be revised annually in accordance with Sections 89(3) and 89(7) of 2008 PA 295.

All customer bills subject to the provisions of this rider, including any bills rendered under special contract, shall be adjusted by the Energy Optimization Surcharge Rider per kWh or Customer as follows:

Tariff	¢/kWh	\$/Customer/Mo.
RS, RS-TOD, RS-TOD2, RS-OPES/PEV, and RS-SC	0.203	
GS (UNMETERED)	0.124	
GS, GS-TOD and GS-TOD 2		6.52
LGS		526.13
LP		526.13
MS		6.52
WSS		6.52
CS-IRP		526.13
RTP		526.13
EHS		6.52
IS		6.52
OSL (UNMETERED)	0.124	
SLS, SLC AND ECLS (UNMETERED)	0.124	
SLCM		6.52

**ISSUED
BY TOBY L. THOMASI
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON AND
AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16- ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

NUCLEAR DECOMMISSIONING SURCHARGE

All customer bills subject to the provisions of this surcharge, including any bills rendered under special contract, shall be adjusted by the Nuclear Decommissioning Surcharge per kWh as follows:

Tariff	¢/kWh
RS, RS-TOD, RS-OPES/PEV, RS-SC, and RS-TOD2	0.100
GS, GS-TOD, and GS-TOD 2	0.113
LGS	0.1035
LP and CS-IRP	0.0896
MS	0.126
WSS	0.095
EHS	0.065
IS	0.157

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16- ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-96.00

RENEWABLE ENERGY SURCHARGE

All customer bills subject to the provisions of this surcharge, including any bills rendered under special contract, shall be adjusted by the Renewable Energy Surcharge adjustment as follows:

Tariff	\$ / Month
RS, RS-TOD, RS-OPES/PEV, RS-SC, and RS-TOD2	3.00
GS-Sec, GS-TOD, , GS-TOD2, WSS-Sec, LGS-Sec, MS, , EHS, IS, SLS, SLC, ECLS, and SLCM	16.58
GS-Pri, GS-Sub, LGS-Pri, LGS-Sub, LP, WSS-Pri, WSS-Sub, CS-IRP, and RTP	187.50

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**M.P.S.C. 16- ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)**

ORIGINAL SHEET NO. D-97.00

NET LOST REVENUE TRACKER SURCHARGE

All customer bills subject to the provisions of this surcharge, including any bills rendered under special contract, shall be adjusted by the Net Lost Revenue Tracker Surcharge per kWh or Customer as follows:

	Power Supply		Delivery		Total	
Tariff		\$/Customer/Mo.		\$/Customer/Mo.		\$/Customer/Mo.
RS, RS-TOD, RS-LM-TOD, and RS-SC		0.00		0.00		0.00
GS (UNMETERED)		0.00		0.00		0.00
GS, GS-TOD and GS-TOD 2		0.0		0.0		0.0
LGS		0.0		0.0		0.0
LP		0.0		0.0		0.0
CS-IRP		0.0		0.0		0.0
RTP		0.0		0.0		0.0
MS		0.0		0.0		0.0
WSS		0.0		0.0		0.0
EHS		0.0		0.0		0.0
IS		0.0		0.0		0.0
OSL (UNMETERED)		0.00		0.00		0.00
SLS, SLC AND ECLS (UNMETERED)		0.00		0.00		0.00
SLCM		0.0		0.0		0.0

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

LOW-INCOME ENERGY ASSISTANCE FUND SURCHARGE

The Low-Income Energy Assistance Fund Surcharge shall be added monthly to each retail billing meter account, but no more than one residential meter per residential site.

All customer bills subject to the provisions of this surcharge, including any bills rendered under special contract, shall be adjusted by the Low-Income Energy Assistance Fund Surcharge of \$0.96 per meter per month.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

SECTION E

COMPANY TERMS AND CONDITIONS OF OPEN ACCESS DISTRIBUTION SERVICE

1. APPLICATION

These Terms and Conditions of Open Access Distribution Service apply to service under the Company's tariffs that provide for Open Access Distribution Service from the Company. Customers requesting Power Supply (generation and transmission), and Delivery (distribution) service from the Company shall be served under the appropriate Company tariffs and the Terms and Conditions of Standard Service.

Open Access Distribution Service furnished by the Company is subject to the Terms and Conditions of Open Access Distribution Service which are at all times subject to revision, change, modification, or cancellation by the Company, subject to the approval of the Michigan Public Service Commission, and which are, by reference, made a part of all standard contracts (both oral and written) for Open Access Distribution Service. Failure of the Company to enforce any of the terms of these tariffs and/or Terms and Conditions of Open Access Distribution Service shall not be deemed a waiver of its right to do so.

A copy of all Company tariffs and Terms and Conditions of Open Access Distribution Service are on file with the Michigan Public Service Commission and may be inspected by the public in any of the Company's business offices. Upon request, the Company will supply, free of charge, a copy of the rate schedules applicable to service available to existing customers or new applicants for service. When more than one rate schedule is available for the service requested, the customer shall designate the rate schedule on which the application or contract shall be based. Where applicable the customer may change from one rate schedule to another once at the end of each full 12-month period or as specified by tariff or contract, upon written application to the Company. In no case will the Company refund any difference in charges between the rate schedule under which service was supplied in prior periods and the newly selected rate schedule.

A written agreement may be required from each customer before Open Access Distribution Service will be commenced. A copy of the agreement will be furnished to the customer upon request.

By receiving service under a specific tariff, the customer has agreed to all terms and conditions of that tariff. A customer's refusal or inability to sign a contract or agreement as specified by the tariff, in no way relinquishes the customer's obligations as specified in the tariff.

When the customer desires delivery of energy at more than one point, a separate agreement will be required for each separate point of delivery. Service delivered at each point of delivery will be billed separately under the applicable tariff. Conjunctive billing and/or aggregate demands are prohibited.

(Continued on Sheet No. E-2.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-1.00)

For new service/accounts, multiple metering is permitted only for Company convenience.

2. CUSTOMER CHOICE OF AN ALTERNATIVE ELECTRIC SUPPLIER

Customers may elect energy services from a qualified Alternative Electric Supplier (AES). Qualifications and other eligibility criteria for such entities are specified in the Supplier Terms and Conditions of Service. AESs are also subject to any rules and licensing criteria established by the Commission for such entities as also incorporated in the Supplier Terms and Conditions of Service.

Any customer who desires service from an AES must first contract with the AES who will arrange for the provision of such services. The AES shall then notify the Company at least 15 calendar days prior to the customer's regularly scheduled meter reading date after which the customer will receive service from the AES. All changes in AES shall occur at the end of the customer's regularly scheduled meter reading date. Any request to change a customer's AES received after 15 calendar days prior to the customer's regularly scheduled meter reading date shall become effective the subsequent billing month.

No more than two AESs may provide competitive retail electric service to a customer during any given month.

Unless otherwise directed, a customer is not permitted to have partial competitive retail electric service. The AES(s) shall be responsible for providing the total energy consumed by the customer during any given month.

The Commission maintains a list of AESs that have been licensed by the Commission. The Company will post on the Company's website a list of those AESs currently registered to enroll customers in the Company's service territory. The Company's list of AESs will also designate, if available, which customer classes each AES will be serving.

3. CHANGING ALTERNATIVE ELECTRIC SUPPLIERS

Standard Service, including Company-provided generation service, will be provided under the Company's tariffs and Terms and Conditions of Standard Service.

(Continued on Sheet No. E-3.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-2.00)

Customers may change AESs no more than once during any month subject to the provisions below.

Requests to change a customer's AES must be received by the Company from the new AES. If the Company receives such a request to change a customer's AES, the customer shall be notified by the Company concerning the requested change within two business days. If the customer challenges the requested change, the change will not be initiated. The customer has ten days from the date on the notice to contact the Company to rescind the enrollment request or notify the Company that the change of AES was not requested by the customer. Within two business days after receiving a customer request to rescind enrollment with an AES, the Company shall initiate such rescission and mail the customer confirmation that such action has been taken.

The customer shall pay a charge of \$5.00 to the Company for each transaction in which a customer authorizes a change in one or more AESs. However, this switching charge shall not apply in the following specific circumstances: (a) the customer's initial change to service under the Company's tariffs and Terms and Conditions of Open Access Distribution Service and service from an AES, (b) the customer's AES is changed involuntarily, (c) the customer returns to service from the customer's former AES following an involuntary change in AES, or (d) the customer's former AES's services have been permanently terminated and the customer must choose another AES.

Customers returning to the Company's Standard Service must remain on the Company's Standard Service for a period of not less than 12 consecutive months. If the customer's return to the Company's Standard Service is the result of AES default or AES withdrawal, the customer shall have 30 calendar days to choose an alternative AES before the above requirement shall apply.

A customer may contact the Company and request to return to the Company's Standard Service. The return to the Company's Standard Service shall be conducted under the same terms and conditions applicable to an enrollment with an AES. The customer will have a ten-calendar day rescission period after requesting a return to the Company's Standard Service. Provided the customer has observed all applicable tariff and contract notification requirements and the Company has effectuated the request to return to the Company's Standard Service at least 15 calendar days prior to the customer's regularly scheduled meter reading date, the customer will be returned to the Company's Standard Service at the end of the customer's regularly scheduled meter reading date.

In the event that an AES's services are permanently terminated, and the AES has not provided

(Continued on Sheet No. E-4.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-3.00)

for service to the affected customers, the AES shall send timely notification to the Company and the affected customers regarding the termination of such services. Such notification shall describe the process for selecting a new AES and note that service will be provided by the Company under the Company's Standard Service if a new AES is not selected within 30 calendar days.

4. BILLS FOR OPEN ACCESS DISTRIBUTION SERVICE

Bills for Open Access Distribution Service will be rendered monthly at intervals of approximately 30 days in accordance with the tariff selected applicable to the customer's service. All bills are rendered as "net" bills that are subject to a late payment charge if the account is delinquent. Late payment charges will be assessed on Residential bills in accordance with Rule 460.122 and on Commercial and Industrial bills in accordance with Rule 460.1614. A late payment charge shall not be assessed against any residential customers who are participating in the winter protection plan as described in Rule 460.148 and Rule 460.149 of the Consumer Standards and Billing Practices for Residential Customers. Any governmental agency shall be allowed such additional period of time for payment of the net bill as the agency's normal fiscal operations require, not to exceed 30 days.

Unless the Open Access Distribution customer's AES has made arrangements with the Company to provide a Company issued consolidated bill, the Company will provide a separate billing for distribution services under the provisions of this tariff.

At the Company's discretion, any customer receiving Company consolidated billing with an AES billing arrearage of more than 60 days may be switched back to the Company's Standard Tariffs and will not be permitted to select a new AES until the arrearage is paid.

Should a partial payment be made in lieu of the total payment of the amount owed to the Company, the payment provisions of the applicable tariff shall apply. If a partial payment is made, such partial payment shall be applied to the various portions of the customer's bill in the following order:

- 1) Prior distribution, Standard Service power supply charges.
- 2) Current distribution, Standard Service power supply charges.
- 3) Prior AES charges.
- 4) Current AES charges.
- 5) Other prior and current non-regulated charges.

5. INSPECTION

It is to the interest of the customer to properly install and maintain customer-owned wiring and electrical equipment, and the customer shall at all times be responsible for the character and condition thereof. The Company makes no inspection thereof and in no event shall be responsible therefore.

Where a customer's premises are located in a municipality or other governmental subdivision where inspection laws or ordinances are in effect, the Company may withhold furnishing service to new installations or disconnected existing installations until it has received evidence that the inspection laws

(Continued on Sheet No. E-5.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-4.00)

or ordinances have been complied with. In addition, if such municipality or other governmental subdivision shall determine that such inspection laws or ordinances are no longer being complied with in respect to an existing installation, the Company may suspend the furnishing of service thereto until it has received evidence of compliance with such laws or ordinances.

Before furnishing service, the Company shall require a certificate or notice of approval from a duly recognized authority stating that customer's wiring has been installed in accordance with local and state requirements.

No responsibility shall attach to the Company because of any waiver of these requirements.

6. SERVICE CONNECTIONS

The Company will, when requested to furnish Open Access Distribution Service, designate the location of its service connection. The customer's wiring must, except for those cases listed below, be brought outside the building wall nearest the Company's service wires so as to be readily accessible thereto. When service is from an overhead system, the customer's wiring must extend a distance beyond the building as established by local codes and Company standards. Where customers install service entrance facilities as specified by the Company and/or install and use certain utilization equipment as specified by the Company, the Company may provide or offer to own certain facilities beyond the point where the Company's service wires attach to the building.

The Company reserves the right to make final determination of selection, application, location, routing and design of its service facilities and meter location. If the customer requests special routing of the service facilities and or meter location, the customer will be required to pay the extra cost, if any, resulting from the special routing of service facilities and or meter location.

All customers' wiring must be grounded in accordance with the requirements of the National Electrical Code or the requirements of any local inspection service authorized by a state or local authority.

When a customer desires that Open Access Distribution Service be provided at a point or in a manner other than that designated by the Company, the customer shall pay the additional cost of same, including any and all required engineering studies.

When a customer requests additional engineering studies beyond the normal overhead and/or underground options providing an adequate plan of service, as designated by the Company, for a new or relocated service, the Company shall charge the customer, payable in advance, for actual cost incurred by the Company to conduct such studies. Normal engineering studies include any obvious options such as overhead and underground installations.

Where Open Access Distribution Service is supplied from an underground distribution system that has been installed at the Company's expense, the customer shall make arrangements with the Company for the Company to supply and install a continuous run of cable conductors including necessary ducts from the manhole or connection box to the meter location where it is necessary that the location of the meter be inside the customer's building. The customer shall reimburse the Company for

(Continued on Sheet No. E-6.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-5.00)

the cost of the portion of cable and duct from the property line to the terminus of cable inside the building.

7. LOCATION AND MAINTENANCE OF COMPANY'S EQUIPMENT

The Company shall have the right to construct its poles, lines, and circuits on the property and to place its transformers and other apparatus on the property or within the buildings of the customer, at a point or points convenient for the purpose, as required to provide Open Access Distribution Service to the customer. The customer shall keep company equipment clear from obstruction and obstacles including landscaping, structures, etc., and provide suitable space for the installation, repair and maintenance of necessary measuring instruments so that the instruments may be protected from injury by the elements or through negligence or deliberate acts of the customer or any other person who is not an agent or employee of the Company.

When Company facilities are damaged due to customer actions or negligence, the Customer shall be responsible for the costs of repairs.

8. RELOCATION OF COMPANY'S FACILITIES AT CUSTOMER'S REQUEST

Whenever, at customer's request, the Company's facilities are relocated solely to suit the convenience of customer, the customer shall reimburse the Company for the entire cost incurred in making such change including any and all required engineering studies.

9. COMPANY'S LIABILITY

The Company will use reasonable diligence in delivering a regular and uninterrupted supply of energy to the customer, but does not guarantee uninterrupted service. The Company shall not be liable for damages in case such service should be interrupted or fail by reason of an act of God, the public enemy, accidents, labor disputes, or orders or acts of civil authority. Further, the Company shall not be liable for damages in case such service should be interrupted due to causes or conditions beyond the Company's reasonable control, including extraordinary repairs, breakdowns, or injury to machinery, transmission lines, distribution lines, or other facilities of the Company. Further, the Company shall not be liable for damages for interrupting service to any customer whenever, in the judgment of the Company, such interruption is necessary in order to prevent or limit any instability or disturbance on the electric system of the Company or any electric system interconnected with the Company, such interruptive action to be taken in accordance with predetermined plan and only in situations that threaten massive curtailments of service on the Company's system.

The Company shall not be liable for damages in case such service to the customer should be interrupted by failure of the customer's AES to provide appropriate energy to the Company for delivery to the customer.

Unless otherwise provided in a contract between Company and customer, the point at which service is delivered by Company to customer, to be known as "delivery point," shall be the point at which the customer's facilities are connected to the Company's facilities. The metering device is the property of the Company; however, the meter base and all internal parts inside the meter base are customer owned and are the responsibility of the customer to install and maintain. The Company shall not be liable for

(Continued on Sheet No. E-7.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-6.00)

any loss, injury, or damage resulting from the customer's use of customer-owned equipment or occasioned by the delivery of energy beyond the delivery point. The Company shall not be liable for any loss, injury, or damage caused by equipment that is not owned, installed, and maintained by the Company.

The customer shall provide and maintain suitable protective devices on the customer's equipment to prevent any loss, injury, or damage that might result from single-phasing conditions or any other fluctuation or irregularity in the delivery of energy. The Company shall not be liable for any loss, injury, or damage resulting from a single-phasing condition or any other fluctuation or irregularity in the delivery of energy that could have been prevented by the use of such protective devices. The Company shall not be liable for any damages, whether direct or consequential, including, without limitations, loss of profits, loss of revenue, or loss of production capacity occasioned by interruptions, fluctuations or irregularity in the supply of energy.

The Company is not responsible for loss or damage caused by the disconnection or reconnection of service to the customer's facilities. The Company is not responsible for loss or damages to customer's property caused by the theft or destruction of Company facilities by a third party.

The Company will provide and maintain the necessary line or service connections, transformers (when the same are required by conditions of contract between the parties thereto), and other apparatus that may be required for protection to its service. All such apparatus shall be and remain the property of the Company. The Company will provide and maintain the necessary meters and other apparatus that may be required for the proper measurement of service. All such apparatus shall be and remain the property of the Company.

10. CUSTOMER'S LIABILITY

In the event of loss or injury to the property of the Company through misuse by, or the negligence of, the customer or the employees of the same, the cost of the necessary repairs or replacement thereof shall be paid to the Company by the customer.

The customer shall be responsible and, therefore, shall insure that no one except Company employees or agents of the Company shall make any internal or external adjustments to, or otherwise interfere with, or break the seals of Company-owned meters or other Company-owned equipment installed on customer's property.

The customer shall be responsible and, therefore, shall insure that no one except Company employees or their agents shall make any internal or external adjustments to, or otherwise interfere with, or break the seals of meters or other related apparatus, regardless of ownership.

The Company shall have the right to enter, at all reasonable hours, the premises of the customer for the purpose of installing, reading, removing, testing, replacing, or otherwise disposing of its apparatus and property, and the right of entire removal of the Company's property in the event of termination of service for any cause. The customer must keep the immediate area and access area in and around the Company's equipment clean and free of debris.

(Continued on Sheet No. E-8.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-7.00)

11. USE OF SERVICE BY CUSTOMER

The tariffs for Open Access Distribution Service given herein are classified by the character of use of such service and are not available for service other than as provided herein. Service will not be furnished under any tariff of the Company on file with the Commission to any customer, applicant, or group of applicants desiring service with the intent or for the purpose of reselling any or all of such service. It shall be understood that upon the expiration of a contract, the customer may elect to renew the contract upon the same or another tariff published by the Company available in the locality in which the customer resides or operates and applicable to the customer's requirements. In no case shall the Company be required to maintain transmission, switching, or transformation equipment (either for voltage or form of current change) different from, or in addition to, that generally furnished to other customers receiving service under the terms of the tariff elected by the customer.

A customer may not change from one tariff to another during the term of contract except with the consent of the Company or within a reasonable period after a Commission-approved change in tariffs.

A customer desiring to change from Open Access Distribution Service to Standard Service must comply with the provisions of Changing Competitive Service Providers, the Term of Contract provision of the tariff under which the customer is receiving service, and the terms of any other agreement between the customer and the Company.

The service connections, transformers, meters, and appliances supplied by the Company for each customer have a definite capacity and no additions to the equipment, or load connected thereto, will be allowed except by consent of the Company.

The customer shall install only motors, apparatus, or appliances that are suitable for operation with the character of the service supplied by the Company, which shall not be detrimental to same, and the electric power must not be used in such a manner as to cause unprovided-for voltage fluctuations or disturbances in the Company's transmission or distribution system. The Company shall be the sole judge as to the suitability of apparatus or appliances and also as to whether the operation of such apparatus or appliances is, or will be, detrimental to its general service.

The customer is responsible to provide any timing equipment and timing control signals to operate time differentiated load.

No attachment of any kind whatsoever may be made to the Company's lines, poles, crossarms, structures, or other facilities without the express written consent of the Company.

All apparatus used by the customer shall be of such type as to secure the highest practicable commercial efficiency, power factor, and the proper balancing of phases. Motors that are frequently started or arranged for automatic control must be of a type to give maximum starting torque with minimum current flow and of a type and equipped with controlling devices approved by the Company. The customer agrees to notify the Company of any increase or decrease in the customer's connected load.

(Continued on Sheet No. E-9.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-8.00)

The operation of certain electrical equipment can result in disturbances (e.g., voltage fluctuations, harmonics, etc.) on the Company's transmission and distribution systems that can adversely impact the operation of equipment for other customers. Customers are expected to abide by industry standards, such as those contained in ANSI/IEEE 519 or the IEEE/GE voltage flicker criteria, when operating such equipment. The Company may refuse or disconnect service to customers for using electricity or equipment that adversely affects distribution service to other customers. Copies of the applicable criteria are available upon request.

Customers with cogeneration, small power production facilities, or other on-site sources of electric energy supply designed to operate in parallel with the Company's system shall take service by special agreement with the Company.

The customer shall not be permitted to operate the customer's own generating equipment in parallel with the Company's service except on written permission of the Company.

12. RESIDENTIAL SERVICE

Individual residences shall be served individually with single-phase service under the appropriate residential tariff. Customers may not take Open Access Distribution Service for three or more separate living units through a single point of delivery under any tariff, irrespective of common ownership of the several residences, except that in the case of an existing apartment house with a number of individual apartments, the landlord shall have the choice of providing separate wiring for each apartment so that the Company may provide delivery to each apartment separately under the residential tariff or purchasing the entire Open Access Distribution Service through a single meter under the appropriate general service tariff. This central metering provision shall not be permitted for new customers.

In a two-family dwelling the owner may, at the owner's option, take Open Access Distribution Service through a single meter under the residential tariff instead of providing separate wiring for both dwelling units. When Open Access Distribution Service is taken through a single meter, the two-family dwelling will be billed as a single-family residence.

The residential tariff shall cease to apply to that portion of a residence that becomes regularly used for business, professional, institutional, or other gainful purposes or which requires three-phase service. Single-phase motors of 10 HP or less may be served under the appropriate residential tariff. Larger single-phase motors may be served where, in the Company's sole judgment, the existing facilities of the Company are adequate.

Under these circumstances, customer shall have the choice of: (1) separating the wiring so that the residential portion of the premises is served through a separate meter under the residential tariff and the other uses as enumerated above are served through a separate meter or meters under the appropriate general service tariff or (2) taking the entire service under the appropriate general service tariff.

Detached building or buildings actually appurtenant to the residence, such as a garage, stable, or barn, may be served by an extension of the customer's residence wiring through the residence meter.

(Continued on Sheet No. E-10.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-9.00)

13. RESORT SERVICE

Where customers desire Open Access Distribution Service for summer homes, summer resort hotels, or other summer resort establishments that are located adjacent to existing distribution lines of the Company and can be served without the extension of primary lines, they shall have the privilege of purchasing all-year distribution service under the applicable all-year tariffs or of purchasing Open Access Distribution Service for less than a full year under the applicable residential or general service tariffs, subject to payment in advance of an amount commensurate with the cost of handling the customer's account, for connection to and disconnection from the Company's lines.

14. TRANSMISSION SERVICE

Transmission service shall be made available under the terms and conditions contained within the applicable Open Access Transmission Tariff as filed with and accepted by the Federal Energy Regulatory Commission. PJM Interconnection, LLC shall be the Transmission Provider. The AES or the customer shall contract for transmission service under the applicable Open Access Transmission Tariff. The contracting entity or its designee is responsible for scheduling under the applicable Open Access Transmission Tariff. Unless other arrangements have been made, the scheduling entity will be billed by the Transmission Provider for transmission services. The contracting entity must also purchase or provide ancillary services as specified under the applicable Open Access Transmission Tariff.

Billing and payment shall be performed as specified in the applicable Open Access Transmission Tariff. Any remaining unpaid amounts and associated fees for transmission service are the responsibility of the customer.

Provisions for scheduling and imbalance are contained within the applicable Open Access Transmission Tariff.

15. LOSSES

The AES or the Transmission Provider shall provide, through appropriate arrangements, both transmission and distribution losses as required to serve customers at various delivery voltages. If an AES arranges to provide transmission losses under the provisions of the applicable Open Access Transmission Tariff, then the AES must also arrange for the appropriate distribution losses. Customers served at transmission and subtransmission voltages require no additional losses other than the losses specified in the applicable Open Access Transmission Tariff. Customers served at primary distribution voltage require 2.8% additional losses of amounts received by the Transmission Provider for delivery to the customer. Customers served at secondary distribution voltage require 5.4% additional losses of amounts received by the Transmission Provider for delivery to the customer.

(Continued on Sheet No. E-11.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-10.00)

16. METERING AND LOAD PROFILING

All customers taking service under the Company's Terms and Conditions of Open Access Distribution Service with maximum monthly billing demands of 200 kW or greater for the most recent 12 months shall be interval metered. The customer, or the customer's AES, may request an interval meter for customers with maximum monthly billing demands less than 200 kW.

The cost of any interval metering facilities installed by the Company to comply with this requirement or as a result of such request shall be paid by the customer. The customer shall make a one-time payment for the metering facilities at the time of installation of the required facilities. In addition, the customer shall pay a monthly net charge of \$0.18 to cover the incremental cost of operation and maintenance and meter data management associated with such interval metering.

In addition, the customer shall pay for service performed on a Company-installed standard interval meter as follows:

Service Performed During Normal Business Hours	Charge (\$)
Connect phone line to meter at a time other than the initial interval meter installation	54.00
Perform manual meter reading	40.00
Check phone line and perform manual meter reading due to communication loss	45.00

The customer, or the customer's AES, may select a meter from the Company's approved equipment list. The customer, or the customer's AES, may communicate with the meter for the purpose of obtaining usage data, subject to the Company's communication protocol. The customer is responsible for providing the telephone line for purposes of reading the meter.

A customer that is required to have interval metering must approve a work order for interval meter installation before an AES may serve such customer. During the period between when the customer has requested an interval meter and the time that the Company is able to install such a meter, a Company load profile will be used for settlement purposes and consumption meter readings will be used for billing.

All load profiling shall be performed by the Company. Sample data and customer specific interval metering, when available, will be used in the development of the total load profile for which an AES is responsible for providing generation and possibly arranging transmission services. Such data shall be provided to other entities as required for monthly billing.

Meters shall be provided and maintained by the Company. Unless otherwise specified, such meters shall be and remain the property of the Company.

(Continued on Sheet No. E-12.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-11.00)

17. EXTENSION OF SERVICE

A. Residential Service

i. Charges

For each permanent, year-round dwelling, the Company will provide a single-phase line extension, excluding service drop, at no additional charge for a distance of 200 feet. Distribution line extensions in excess of the above footages will require an advance deposit of \$ 3.50 per foot for all such excess footage. There will also be a nonrefundable contribution equal to the cost of right-of-way and clearing on such excess footage. Three-phase extensions, as required to service large developments, will be on the same basis as Commercial and Industrial.

ii. Measurement

The length of any main line distribution feeder extension will be measured along the route of the extension from the Company's nearest facilities from which the extension can be made to the customer's property line. The length of any lateral extension on the customer's property shall be measured from the customer's property line to the service pole. Should the Company, for its own reasons, choose a longer route, the applicant will not be charged for the additional distance; however, if the customer requests special routing of the line, the customer will be required to pay the extra cost resulting from the special routing.

iii. Refunds

During the five-year period immediately following the date of payment, the Company will make refunds of the charges paid for a financed extension under provisions of paragraph (i) above. The amount of any such refund shall be \$165 for each permanent electric service subsequently connected directly to the facilities financed by the customer. Directly connected customers are those that do not require the construction of more than 100 feet of lateral primary distribution line. Such refunds will be made only to the original depositor and will not include any amount of contribution in aid of construction for underground service made under the provisions of the Company's underground service policy as set forth in this section. The total refund shall not exceed the refundable portion of the contribution.

B. Commercial or Industrial Service

Investment, charges, and refunds related to extension of service for Open Access Distribution customers will be determined by the same method as used for Standard Service customers. The capacity power supply charge revenue anticipated for Open Access Distribution customers will be calculated using the same capacity power supply charges used for Standard Service Customers.

i. Company Financed Extensions

Except for contributions in aid of construction for underground service made under the provisions of Item 18, C of these rules, the Company will finance the construction cost

(Continued on Sheet No. E-13.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-12.00)

necessary to extend its facilities to serve commercial or industrial customers when such investment does not exceed two times the annual capacity power supply and delivery charge revenue anticipated to be collected from customers initially served by the extension.

ii. Charges

When the estimated cost of construction of such facilities exceeds the Company's maximum initial investment as defined in paragraph (i), the applicant shall be required to make a deposit in the entire amount of such excess construction costs. Owners or developers of mobile home parks shall be required to deposit the entire amount of the estimated cost of construction, subject to the refund provisions of paragraph (iii).

iii. Refunds

That portion of the deposit related to the difference in the cost of underground construction and the equivalent overhead facilities shall be considered nonrefundable. This amount shall be determined under the applicable provisions of the Company's underground service policy as set forth in this section.

The Company will make refunds on remaining amounts of deposits collected under the provisions of paragraph (ii) above in cases where actual experience shows that the capacity power supply and delivery charge revenues supplied by the customer are sufficient to warrant a greater initial investment by the Company. Such refunds shall be computed as follows:

(1) Original Customer

At the end of the first complete 12-month period immediately following the date of initial service, the Company will compute a revised revenue credit based on two times the actual capacity power supply and delivery charge revenue provided by the original customer in the 12-month period. Any amount by which twice the actual annual capacity power supply and delivery charge revenue exceeds the Company's initial revenue estimate will be made available for refund to the customer; no such refund shall exceed the amount deposited under provisions of paragraph (ii) above.

(2) Refunds for additional new customers directly connected to the financed extension during the refund period will be governed by Section 18, A, iii.

iv. Loads of Uncertain Duration

When, in the opinion of the Company, the permanence and continuance of the customer's load is questionable, the Company may require the applicant to make an advance deposit for line construction or service to cover the Company's costs of extending its electric lines and furnishing and installing necessary transformation, metering and protective equipment to supply electricity to the customer's premises. The advance deposit with the Company will be made up of two components (1) the estimated cost of constructing the facilities to serve the customer, including labor, material, stores freight and handling expenses, and a charge for overhead, plus (2) the estimated cost of removing said facilities and returning the materials to

(Continued on Sheet No. E-14.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-13.00)

the Company storeroom, minus the estimated value of salvaged materials to be returned to storeroom at the end of the electrical service.

Any customer making an advance deposit under this section is eligible for a rebate of the monies advanced under (1) of the preceding paragraph, beginning with the first full billing month for full operation of the customer's facility and ending with the 24th consecutive month thereafter. The rebate will be 40% of the monthly electric service paid by the customer. The total amount of all rebates shall not exceed the amount of the monies advanced under (1) of the preceding paragraph. In addition, following the continuous use of electric service for twenty-four (24) months, any monies held by the Company will be promptly refunded to the customer. The Company, at its discretion, may accept a letter of credit or performance bond, payable to the Company, in lieu of an advance deposit.

C. General

The Company will extend its lines to serve domestic customers and farm customers for year-round service under applicable tariffs subject to the following conditions:

- (1) Extensions hereunder shall be built by the Company in accordance with its construction standards and shall be single phase unless the Company elects to build polyphase lines.
- (2) In those cases where it is not feasible or practicable to construct lines on public rights-of-way and it is necessary to secure rights-of-way on private property or tree trimming permits, the applicant or applicants shall secure the same without cost to the Company, or assist the Company, in obtaining such rights-of-way on private property or tree trimming permits before construction shall commence. The Company shall be under no obligation to construct lines in event the necessary rights-of-way or tree-trimming permits cannot be so obtained.

18. UNDERGROUND ELECTRIC LINES

A. General

In case of all direct burial underground extensions of electric distribution facilities as covered by conditions as set forth in this section, the real estate developer or customer shall make a nonrefundable contribution in aid of construction to the Company in an amount equal to the estimated difference in cost between overhead and direct burial underground facilities. "Distribution facilities" means those operated at 20,000 volts or less to ground for wye connected systems and 20,000 volts or less for delta connected systems. Charges in this section are in addition to any charges that may be required in Section 17 for equivalent overhead facilities.

(Continued on Sheet No. E-15.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-14.00)

B. Residential

i. In Subdivisions

(1) Distribution Facilities

The distribution system in a new residential subdivision and an existing residential subdivision in which electric distribution facilities have not already been constructed shall be placed underground, except that a lot facing a previously existing street or county road and having an existing overhead distribution line on its side of the street or county road shall be served with an underground service from these facilities and shall be considered a part of the underground service area.

The owner or developer of such subdivisions shall be required to make a nonrefundable contribution in aid of construction to the Company, for direct burial underground distribution facilities, in an amount equal to the sum of the lot front-foot measurement multiplied by \$ 4.50, which amount shall be considered to be the difference in cost between overhead and direct burial underground distribution facilities.

The front-foot measurement of each lot to be served by a residential underground distribution system shall be made along the contour of the front lot line. The front lot line is that line which usually borders on or is adjacent to a street. However, when streets border on more than one side of a lot, the shortest dimension shall be used. In case of a curved lot line that borders on a street or streets and represents at least two sides of the lot, the front-foot measurements shall be considered as one-half the total measurement of the curved lot line. Where a lot is served by an underground service from an overhead distribution line, the lot front-foot measurement shall be deleted. The construction provided for in the \$ 4.50 per lot front-foot contribution in aid of construction includes the extension of underground electric distribution facilities to the lot line of each lot in the subdivision.

The use of the lot front-foot measurement in these rules shall not be construed to require that the underground electric distribution facilities be placed on the front of the lot.

(2) Service Facilities

The Company shall install, own, and maintain the service line from the property line to the customer's meter. For normal installation of the service line, the developer or customer shall make a nonrefundable contribution in aid of construction to the Company in an amount equal to \$ 6.00 per trench foot.

ii. Outside of Subdivisions

(3) Distribution Facilities

The customer located outside of subdivisions shall be required to make a nonrefundable

(Continued on Sheet No. E-16.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-15.00)

contribution in aid of construction to the Company in an amount equal to the estimated total difference in cost between overhead and underground construction costs.

(4) Service Facilities

For normal installation of the service line, the customer shall make a nonrefundable contribution in aid of construction to the Company in an amount equal to \$ 6.00 per trench foot.

iii. Mobile Home Parks, Condominiums and Apartment House Complexes

The distribution and service facilities for new and existing mobile home parks, condominiums, and apartment house complexes in which electric facilities have not already been constructed shall be placed underground.

The owner or developer of such mobile home parks, condominiums, and apartment house complexes shall be required to make a nonrefundable contribution in aid of construction to the Company for distribution facilities in an amount equal to \$ 4.50 per trench foot and service facilities in an amount equal to \$ 12.25 per trench foot and \$ 11.25 per kVA for transformers (installed). Owners or developers of mobile home parks shall be required to deposit the entire amount of the estimated cost of construction, subject to the refund provisions of Section 17 B (iii).

C. Commercial and Industrial

Commercial distribution and service lines in the vicinity of the customer's property and constructed solely to serve a customer or group of adjacent customers shall be placed underground. This will specifically include, but not be limited to, service to shopping centers.

Industrial distribution and service lines shall be placed underground at the option of the customer. The developer or customer shall be required to make a nonrefundable contribution in aid of construction to the Company for the following facilities which amount shall be considered to be the difference in cost between overhead and direct burial underground facilities:

- | | | |
|------|---|---|
| i. | Distribution facilities - | Single-phase – \$ 4.50 per trench foot.
Three-phase – \$3.00 per trench foot. |
| ii. | Transformers - | Single-phase – \$ 8.00 per kVA (installed).
Three-phase – \$12.50 per kVA (installed). |
| iii. | Service, as this term is generally understood in the electric utility field, (on customer's property) - | Single-phase – \$ 8.00 per trench foot.
Three-phase – \$12.50 per trench foot. |

(Continued on Sheet No. E-17.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-16.00)

D. Special Conditions

Where practical difficulties exist, such as water conditions, rock near the surface, or where there are requirements for deviation from the Company's construction standards such as directional boring, the per foot charges in B and C will not apply and the contribution in aid of construction will be equal to the estimated difference in cost between overhead and underground facilities but not less than the charge calculated under B and C.

An additional amount of \$1 per foot shall be added to the trenching charges for the practical difficulties associated with winter construction in the period from December 15 to March 31, inclusive. This charge will not apply to jobs that are ready for construction and for which the construction meeting has been held prior to November 1.

E. Replacement of Existing Overhead Electric Facilities

Existing overhead residential, commercial, and industrial electric distribution and service lines shall be replaced with underground facilities at the option of the affected customer or customers. Before construction is started, the customer shall be required to pay the Company the depreciated cost (net cost) of the existing overhead facilities plus the cost of removal less the salvage value thereof and, also, make a nonrefundable contribution in aid of construction in an amount equal to the estimated difference in cost between new underground and new overhead facilities including, but not limited to, the costs of breaking and repairing streets, walks, parking lots, and driveways, repairing lawns, and replacing grass, shrubs, and flowers.

19. TEMPORARY SERVICE

Temporary service is electric service that is required during the construction phase of a project and/or electric service that is provided to new customers for a period not to exceed 12 months except in cases of large construction projects and the customer has notified the Company of the need to extend this timeframe. Such service is available only upon approval of the Company. In order to qualify for temporary service, the customer must demonstrate to the Company's satisfaction that the requested service will, in fact, be temporary in nature.

Temporary service for residential construction will be supplied using Tariff R.S. Temporary service for general service construction will be supplied under the appropriate published general service tariff applicable to the class of business of the customer. Temporary service will be supplied when the Company has available unsold capacity of lines and transformers. The customer will be charged a minimum temporary service installation charge in addition to the service charge set forth in the tariff under which temporary service is supplied. The service charge, as set forth in the applicable tariff shall be, in no case, less than one full monthly amount. The customer will be charged a minimum temporary service installation charge, payable in advance, based on the Company's actual cost to install and remove, less salvage, the required facilities to provide the temporary service. In no case shall revenue credits apply to cover costs associated with temporary service. The Company reserves the right to require a written contract for temporary service, at its option.

(Continued on Sheet No. E-18.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-17.00)

20. DENIAL OR DISCONTINUANCE OF SERVICE

Pursuant to Rules 460.136, 460.137, and 460.1625, the Company reserves the right to shutoff service to any customer without notice, in case of an emergency or to prevent fraud upon the Company. Additional shutoff of service rules applicable to nonresidential service are set forth in the MPSC Rules in Part 7 of the Billing Practices Applicable to Non-Residential Electric and Gas Customers, as referenced herein, and are set forth, as applicable, to residential service in Part 8 of the Consumer Standards and Billing Practices for Electric and Gas Residential Service, as referenced herein.

Any shutoff of service shall not terminate the contract between the Company and the customer nor shall it abrogate any minimum charge that may be effective.

The Company may disconnect service without request by the customer and with proper notification in writing of at least 14 days when:

- (a) The customer does not provide adequate access to the meter during normal business hours or denies access to other Company equipment; or
- (b) The customer does not provide adequate safe clearance in front of and around metering and associated equipment; or
- (c) The customer does not allow safe egress and regress across the customer's property to access metering and other Company equipment; or
- (d) The meter is located in an inaccessible location such as a basement, fenced area, porch, etc., and the customer denies the Company reasonable access; or
- (e) The customer's equipment falls into disrepair due to aging or abuse and needs to be replaced due to eminent safety considerations; or
- (f) The meter installation does not fall under commonly acceptable installation practices or where conditions at the customer's site change, causing the meter installation to no longer meet acceptable installation guidelines.

The Company may disconnect service without request by the customer and without prior notice only:

- (a) If a condition dangerous or hazardous to life, physical safety, or property exists; or
- (b) Upon order by any court, the Commission or other duly authorized Public Authority; or
- (c) If fraudulent or unauthorized use of electricity is detected and the Company has reasonable grounds to believe the affected customer is responsible for such use; or
- (d) If the Company's regulating or measuring equipment has been tampered with and the Company has reasonable grounds to believe that the affected customer is responsible for such tampering.

(Continued on Sheet No. E-19.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-18.00)

21. VOLTAGES

The standard nominal distribution service voltages within the service area of the Company are:

Secondary		Primary	
Single Phase	Three Phase	Single Phase	Three Phase
120/240 Volts	120/208 Volts	2400 Volts**	4160/2400 Volts**
120/208 Volts	120/240 Volts*	7200 Volts	12470/7200 Volts
480 Volts	277/480 Volts	19950 Volts	34500/19950 Volts
	480 Volts*		

* Not available when supplied from 34500/19950 primary distribution systems.

** Limited to existing 4160/2400 volt distribution systems or from a dedicated subtransmission or transmission station.

The standard subtransmission and transmission service voltages within the service area of the Company are:

Subtransmission	Transmission
Three Phase	Three Phase
34.5 kV	138 kV
69 kV	345 kV
	765 kV

22. SPECIAL SERVICE CHARGES

The following schedule reflects the amounts to be charged for the special services stipulated. The Company will endeavor to comply with customer requested work subject to a minimum of three days prior notification and / or manpower availability.

SCHEDULE OF CHARGES	AMOUNT
1. Reconnect during regular business hours.	\$62.50
2. Reconnect during workday overtime hours and all day Saturday.	\$80.00
3. Reconnect on Sundays or holidays.	\$156.25
4. Trip charge where Company employees are sent to customer premises to specifically notify the customer that bill payment is due.	\$29.00

(Continued on Sheet No. E-20.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-19.00)

5. Disconnect trips where notification is left for the customer at the premises because of access or other issue or the customer signs a Company form agreeing to make payment by the end of business the same day and no disconnect is made.	\$34.25
6. Reconnect when disconnect is required to be made from a vault, manhole, or service box.	\$585.75
7. Reconnect when disconnect is required to be made at pole during regular business hours.	\$78.00
8. Reconnect when disconnect is required to be made at pole during workday overtime hours and all day Saturday.	\$117.00
9. Reconnect when disconnect is required to be made at pole on Sunday or holidays	\$203.00
10. Trip charge for no-power service call when the customer's facilities are clearly at fault or for scheduled work and the customer is not ready when Company is on site and customer was advised of the charge .	\$34.25
11. Meter test or change when charge is permitted in accordance with the the Consumer Standards and Billing Practice Rules.	\$31.25
12. Customer's check returned for nonsufficient funds.	\$18.75

23. MISCELLANEOUS CUSTOMER CHARGES

When the Company detects that its regulating, measuring equipment, or other facilities have been tampered with or when fraudulent or unauthorized use of electricity has occurred, a rebuttable presumption arises that the customer or other user has benefited by such fraudulent or unauthorized use of such tampering. Therefore, that customer or other user is responsible for payment of the reasonable cost of the service used during the period such fraudulent or unauthorized use or tampering occurred or is reasonably assumed to have occurred and is responsible for the cost of field calls and the cost of making repairs necessitated by such use and/or tampering, plus a charge of \$50 per occurrence. Under such circumstances the Company will institute the procedures outlined in the Consumer Standards and Billing Practice Rules.

24. CUSTOMER OWNED EQUIPMENT TROUBLESHOOTING

When requested by the customer to investigate any problems with customer owned equipment that is connected to the Company's system, such as a generator, transformer, or other unique customer-owned facilities, the Company will conduct investigations at no charge to the customer. Company will make all reasonable attempts to resolve any problems when the Company is found to be at fault. If the customer owned equipment is found to be at fault, the Company may at the customer's request, and upon mutual agreement, continue troubleshooting the problem if the customer consents to paying for all additional charges which shall be based on actual labor and material incurred.

(Continued on Sheet No. E-21.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-20.00)

25. TAX ADJUSTMENT AND FRANCHISE FEES

Bills to customers receiving service within the limits of political subdivisions which levy special license fees, franchise fees or any other such fee against the Company or its operation or the production or sale of electric energy shall be increased by a uniform per meter surcharge calculated on an annual basis to offset such special fee or any new or increased special fee, thereby preventing other customers from being compelled to share such local fees.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

**SECTION E
SUPPLIER TERMS AND CONDITIONS OF OPEN ACCESS DISTRIBUTION SERVICE**

1. APPLICATION

These Supplier Terms and Conditions of Service apply to any person that is engaged in the business of supplying electric generation service to customers that take distribution service from the Company (Alternative Electric Supplier).

A copy of the Supplier Terms and Conditions of Service under which service is to be rendered will be furnished upon request.

2. CUSTOMER CHOICE OF ALTERNATIVE ELECTRIC SUPPLIER

Customers taking service under the Company's Terms and Conditions of Open Access Distribution Service may elect energy services from a qualified Alternative Electric Supplier (AES). Such services are allowed under the provisions of Open Access Distribution Service to the extent permitted by law.

Qualifications and other eligibility criteria for such entities are specified herein. AESs are also subject to any rules and licensing criteria established by the Commission for such entities as incorporated herein.

Any customer who desires alternative electric service must first contract with an AES who will arrange for the provision of such service. The AES shall then notify the Company at least 15 calendar days prior to the customer's regularly scheduled meter reading date after which the customer will receive service from the AES. All changes in AES shall occur at the end of the customer's regularly scheduled meter reading date. Any request to change a customer's AES received after 15 calendar days prior to the customer's regularly scheduled meter reading date shall become effective the subsequent billing month.

The Commission maintains a list of AESs that have been licensed by the Commission. The Company will post on the Company's website a list of those AESs currently registered to enroll customers in the Company's service territory. The Company's list of AESs will also designate, if available, which customer classes each AES will be serving.

3. CHANGING ALTERNATIVE ELECTRIC SUPPLIERS

Standard Service, including Company-provided Power Supply service, will be provided under the Company's tariffs and Terms and Conditions of Standard Service.

(Continued on Sheet No. E-23.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. E-22.00)

Customers may change AES no more than once during any month subject to the provisions below.

Requests to change a customer's AES must be received by the Company from the new AES. If the Company receives such a request to change a customer's AES, the customer shall be notified by the Company concerning the requested change within two business days. If the customer challenges the requested change, the change will not be initiated. The customer has ten days from the date on the notice to contact the Company to rescind the enrollment request or notify the Company that the change of AES was not requested by the customer. Within two business days after receiving a customer request to rescind enrollment with an AES, the Company shall initiate such rescission and mail the customer confirmation that such action has been taken.

The customer shall pay a charge of \$5.00 to the Company for each transaction in which a customer authorizes a change in AES. However, this switching charge shall not apply in the following specific circumstances: (a) the customer's initial change to service under the Company's Terms and Conditions of Open Access Distribution Service from an AES, (b) the customer's AES is changed involuntarily, (c) the customer returns to service from the customer's former AES following an involuntary change in AES, or (d) the customer's former AES's services have been permanently terminated and the customer must choose another AES.

Customers returning to the Company's Standard Service must remain on the Company's Standard Service for a period of not less than 12 consecutive months. If the customer's return to the Company's Standard Service is the result of AES default or AES withdrawal, the customer shall have 30 calendar days to choose an alternative AES before the above requirement shall apply.

A customer may contact the Company and request to return to the Company's Standard Service. The return to the Company's Standard Service shall be conducted under the same terms and conditions applicable to an enrollment with an AES. The customer will have a ten-calendar day rescission period after requesting a return to the Company's Standard Service. Provided the customer has observed all applicable tariff and contract notification requirements and the Company has effectuated the request to return to the Company's Standard Service at least 15 calendar days prior to the customer's regularly scheduled meter reading date, the customer will be returned to the Company's Standard Service at the end of the customer's regularly scheduled meter reading date.

In the event that an AES's services are permanently terminated, and the AES has not provided for service to the affected customers, the AES shall send timely notification to the Company and the affected customers regarding the termination of such services. Such notification shall describe the process for selecting a new AES and note that service will be provided by the Company under the Company's Standard Service if a new AES is not selected within 30 calendar days.

4. CUSTOMER ENROLLMENT PROCESS

AESs licensed by the Commission may request, in a standardized electronic transaction, historical customer data after receiving the appropriate customer authorization. The data will be

(Continued on Sheet No. E-24.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. E-23.00)

transferred in a standardized electronic transaction. The AES will be responsible for the incremental costs incurred to prepare and send such data.

Enrollment of a customer is done through a Direct Access Service Request (DASR), which may be submitted only by an AES.

DASRs will be effective on the first day of the next billing month provided that the DASR is received by the Company during the current enrollment period that ends 15 calendar days prior to the beginning of that billing month.

The Company will process all valid DASRs and send the confirmation notice to the customer within two business days. Simultaneous with the sending of the confirmation notice to the customer, the Company will electronically advise the AES of acceptance. Notice of rejection of the DASR to the AES shall be sent within four calendar days and include the reasons for the rejection. The customer has ten calendar days from the confirmation notice to cancel the contract without penalty. If the customer cancels the contract, the Company shall send a drop notice to the AES and the previous AES will continue to serve the customer under the terms and conditions in effect prior to submission of the new DASR.

DASRs will be processed on a "first in" priority basis based on the received date, and using contract date as the tiebreaker. Any subsequent DASRs received within the same enrollment period will be rejected and returned to the AES who submitted the DASR.

To receive service from an AES, a customer must have an active service account with the Company. After the service account is active, an AES may submit a DASR as described herein.

5. CUSTOMER PROTECTIONS

The maximum early termination fee for residential contracts of one year or less shall not exceed \$50. The maximum early termination fee for residential contracts of longer than one year shall not exceed \$100.

It is the AES's responsibility to have a current valid contract with the customer at all times. Any contract that is not signed by the customer or legally authorized person shall be considered null and void. Only the customer account holder or legally authorized person shall be permitted to sign a contract. An AES and its agent shall make reasonable inquiries to confirm that the individual signing the contract is a legally authorized person. Legally Authorized Person means a person that has legal documentation or legal authority to enroll a residential or non-residential customer into a binding contract. A legally authorized person includes but is not limited to, an individual with power of attorney or a corporate agent authorized to enter into contracts on a corporation's behalf.

For each customer, an AES must be able to demonstrate that a customer has made a knowing selection of the AES by at least one of the following verification records:

- (1) An original signature from the customer account holder or legally authorized person.
- (2) Independent third party verification with an audio recording of the entire verification call.

(Continued on Sheet No. E-25.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. E-23.00)

(3) An email address if signed up through the Internet.

The Commission or its Staff may request a reasonable number of records from an AES to verify compliance with this customer verification provision and, in addition, may request records for any customer due to a dispute.

An AES must allow the Staff of the Commission an opportunity to review and comment on its residential contract(s) and residential marketing material at least five business days before the AES intends to use these contract(s) and marketing material in the marketplace.

An AES must distribute a confirmation letter to residential customers by U.S. mail. The confirmation letter must be postmarked within seven (7) days of the customer or legally authorized person signing a contract with the AES. The confirmation letter must include the date the letter was sent, the date the contract was signed, the term of the contract with end date, the fixed or variable rate charged, the unconditional cancellation period, any early termination fee, the AES's phone number, the Commission's toll-free number and Company's emergency contact information.

The Company shall provide residential customers with pending enrollments with an AES, a 14-day notice period (beginning with the day the Company receives the enrollment from the AES) in which the residential customers may cancel the enrollment before the switch is executed. If the residential customer challenges the enrollment and the switch transaction is cancelled, the affected AES(s) are notified. The enrolling AES cannot reverse the residential customers cancellation.

6. GENERAL PROVISIONS FOR ALTERNATIVE ELECTRIC SUPPLIERS

An AES must comply with any rules and requirements established by the Commission pertaining, but not limited to, general business practices, information disclosure and reporting, customer contract rescission, financial capability, collection and remission of applicable taxes, dispute resolution, customer confidentiality, customer authorization for switching suppliers, involuntary customer contract termination, and supply obligations. An AES must also agree to comply with any applicable provisions of the Company's tariffs, Supplier Terms and Conditions of Service, Terms and Conditions of Open Access Distribution Service, and the applicable Open Access Transmission Tariff.

No more than two AESs may provide competitive retail electric service to a customer during any given month.

Unless otherwise directed, a customer is not permitted to have partial competitive retail electric service. The AES(s) shall be responsible for providing the total energy consumed by the customer during any given month.

7. SUPPLIER LICENSING WITH THE COMMISSION

Suppliers desiring to become AESs must first be licensed by the Commission and shall be subject to the licensing criteria adopted by the Commission according to 2000 PA 141.

(Continued on Sheet No. E-25.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. E-24.00)

8. AES REGISTRATION WITH THE COMPANY

AESs desiring to provide competitive retail electric service to customers located within the Company's Service Territory must also register with the Company. The AES shall submit a completed registration application, on the form provided by the Company. A copy of the registration application will be furnished upon request. The following information must also be provided in order to register with the Company:

- A. Proof of licensure by the Commission, including any information provided to the Commission as part of the licensing process. The registration process may be initiated upon receipt by the Company of an application for licensure by the Commission. However, the Company will not complete the registration process until proof of licensure by the Commission has been provided.
- B. A completed copy of the Company's AES Registration Application, along with a non-refundable \$100 registration fee payable to the Company.
- C. After the first year, a \$100 annual registration fee payable to the Company.
- D. An appropriate financial instrument to be held by the Company against AES defaults and a description of the AES's plan to procure sufficient electric energy and transmission services to meet the requirements of its firm service customers.
- E. The name of the AES, business and mailing addresses, and the names, telephone numbers, and e-mail addresses of appropriate contact persons, including the 24-hour emergency contact telephone number and emergency contact person(s).
- F. Details of the AES's dispute resolution process for customer complaints.
- G. A signed statement by the officer(s) of the AES committing it to adhere to the Company's tariffs, Terms and Conditions of Open Access Distribution Service, Supplier Terms and Conditions of Service, and any additional requirements stated in any agreement between the AES and the Company regarding services provided by either party.
- H. Completed copies of the Company's EDI Trading Partner Set-up Form and Trading Partner Certification Checklist.
- I. An Executed EDI Trading Partner Agreement and completion of EDI testing for applicable transaction sets necessary to commence service.

The Company will notify the AES of incomplete registration information within ten calendar days of receipt. The notice to the AES shall include a description of the missing or incomplete information.

(Continued on Sheet No. E-26.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. E-25.00)

The Company shall approve or disapprove the AES's registration within 30 calendar days of receipt of complete registration information from the AES. The 30-day time period may be extended for up to 30 days for good cause shown or until such other time as is mutually agreed to by the AES and the Company.

All applicable agreements, including but not limited to, agreements between the AES and the Company regarding services provided by either party must be executed in order to complete the registration process.

Alternative dispute resolution shall be available to AESs and the Company to address disputes and differences between the parties.

8. AES CREDIT REQUIREMENTS

The Company will apply, on a non-discriminatory and consistent basis, reasonable financial standards to assess and examine an AES's creditworthiness. These standards will take into consideration the scope of operations of each AES and the level of risk to the Company. This determination will be aided by appropriate data concerning the AES, including load data or reasonable estimates thereof, where applicable.

In considering an AES's creditworthiness, the Company will review whether the AES has, and maintains, stable, or better, investment grade senior unsecured (unenhanced) long-term debt ratings from any two of the following three rating agencies:

Agency	Senior Unsecured Long-Term Debt Ratings
Standard & Poors	BBB- or higher
Moody's Investors' Services	Baa3 or higher
Fitch IBCA	BBB- or higher

The AES also will provide the Company, for its creditworthiness determination, with its or its parent's independently-audited financial statements, or Form 10K (if applicable), for the last three fiscal years, and its or its parent's most recent quarterly unaudited financial statements or Form 10Q (if applicable).

For an AES without the requisite investment grade bond rating, or whose credit requirements exceed a level appropriate for its financial resources and bond rating, the AES must have an amount of positive tangible net worth acceptable to the Company and meet risk parameters derived from the Company's analysis of its financial statements. The Company, in its sole judgment, will determine the appropriate amount of unsecured credit to be extended to an AES as a result of this analysis. The AES may provide alternative security or credit enhancement, such as a guarantee of payment in a form acceptable to the Company, a letter of credit in a form and from a financial institution acceptable to the Company, or prepayment. The Company will use reasonable credit review procedures which may include, but are not limited to, review of

(Continued on Sheet No. E-27.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. E-26.00)

the AES's financial statements, verification that the AES is not operating under state or federal bankruptcy laws, and has no pending lawsuits or regulatory proceedings or judgments outstanding which would have a material adverse effect on the AES and its ability to perform its obligations. Affiliates of the Company are subject to these same requirements and must provide proof of creditworthiness consistent with the code of conduct approved by the Commission.

9. TRANSMISSION SERVICE

Transmission service shall be made available under the terms and conditions contained within the applicable Open Access Transmission Tariff as filed with and accepted by the Federal Energy Regulatory Commission. The AES or the customer shall contract with the Transmission Provider for transmission service under the applicable Open Access Transmission Tariff. The Transmission Provider is the applicable regional transmission entity. PJM Interconnection LLC is currently the applicable regional transmission entity. Customers contracting with the Transmission Provider for transmission service and all AESs must complete all required actions relative to membership with the Transmission Provider and be authorized by the Transmission Provider to transact business with regard to transmission service. The contracting entity or its designee is responsible for scheduling under the applicable Open Access Transmission Tariff. Unless other arrangements have been made, the scheduling entity will be billed by the Transmission Provider for transmission services. The contracting entity must also purchase or provide ancillary services as specified under the applicable Open Access Transmission Tariff.

Billing and payment shall be performed as specified in the applicable Open Access Transmission Tariff. Any remaining unpaid amounts and associated fees for transmission service are the responsibility of the customer.

Provisions for scheduling and imbalance are contained within the applicable Open Access Transmission Tariff.

10. LOSSES

The AES or the Transmission Provider shall provide, through appropriate arrangements, both transmission and distribution losses as required to serve customers at various delivery voltages. If an AES arranges to provide transmission losses under the provisions of the applicable Open Access Transmission Tariff, then the AES must also arrange for the appropriate distribution losses. Customers served at transmission and subtransmission voltages require no additional losses other than the losses specified in the applicable Open Access Transmission Tariff. Customers served at primary distribution voltage require 2.8% additional losses of amounts received by the Transmission Provider for delivery to the customer. Customers served at secondary distribution voltage require 5.4% additional losses of amounts received by the Transmission Provider for delivery to the customer.

11. CONSOLIDATED BILLING BY THE COMPANY

Upon request, the Company will offer Company-issued consolidated bills to customers receiving service from an AES upon execution of an appropriate agreement between the AES and the Company. Company-issued consolidated billing will include equal monthly billing as an option. The AES will be

(Continued on Sheet No. E-28.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued from Sheet No. E-27.00)

responsible for the Company's incremental cost of issuing consolidated bills. The AES must electronically provide all information in a bill-ready format.

At the Company's discretion, any customer receiving Company consolidated billing with an AES billing arrearage of more than 60 days may be switched back to the Company's Standard Service and will not be permitted to select a new AES until the arrearage is paid.

If the customer's AES defaults, the Company reserves the right to retain payments collected from the customer and to apply such payments to the Company's charges.

12. METERING AND LOAD PROFILING

All customers taking service under the Company's Terms and Conditions of Open Access Distribution Service with maximum monthly billing demands of 200 kW or greater for the most recent 12 months shall be interval metered. The customer, or the customer's AES, may request an interval meter for customers with maximum monthly billing demands less than 200 kW.

The cost of any interval metering facilities installed by the Company to comply with this requirement or as a result of such request shall be paid by the customer. The customer shall make a one-time payment for the metering facilities at the time of installation of the required facilities.

In addition, the customer shall pay a monthly net charge of \$0.18 to cover the incremental cost of operation and maintenance and meter data management associated with such interval metering.

In addition, the customer shall pay for service performed on a Company-installed standard interval meter as follows:

Service Performed During Normal Business Hours	Charge (\$)
Connect phone line to meter at a time other than the initial interval meter installation	54.00
Perform manual meter reading	40.00
Check phone line and perform manual meter reading due to communication loss	45.00

(Continued on Sheet No. E-29.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-28.00)

The customer, or the customer's AES, may select a meter from the Company's approved equipment list. The customer, or the customer's AES, may communicate with the meter for the purpose of obtaining usage data, subject to the Company's communication protocol. The customer is responsible for providing the telephone line for purposes of reading the meter.

A customer that is required to have interval metering must approve a work order for interval meter installation before an AES may serve such customer. During the period between when the customer has requested an interval meter and the time that the Company is able to install such a meter, a Company load profile will be used for settlement purposes and consumption meter readings will be used for billing.

All load profiling shall be performed by the Company. Sample data and customer specific interval metering, when available, will be used in the development of the total load profile for which an AES is responsible for providing generation and possibly arranging transmission services.

Meters shall be provided and maintained by the Company. Such meters shall be and remain the property of the Company.

13. PAYMENTS

Partial payment from a customer shall be applied to the various portions of the customer's total bill in the following order: (a) prior Delivery, Standard Service Power Supply charges; (b) current Delivery, Standard Service Power Supply charges; (c) prior AES charges; (d) current AES charges; and (e) other prior and current non-regulated charges.

14. CONFIDENTIALITY OF INFORMATION

All confidential or proprietary information made available by one party to the other in connection with the registration of an AES with the Company and/or the subsequent provision and receipt of service under these Supplier Terms and Conditions of Service, including but not limited to load data, and information regarding the business processes of a party and the computer and communication systems owned or leased by a party, shall be used only for purposes of registration with the Company, receiving or providing service under these Supplier Terms and Conditions of Service, and/or providing competitive retail electric service to customers in the Company's service territory. Other than disclosures to representatives of the Company or the AES for the purposes of enabling that party to fulfill its obligations under these Supplier Terms and Conditions of Service or for the AES to provide competitive retail electric service to customers in the Company's service territory, a party may not disclose confidential or proprietary information without the prior authorization and/or consent of the other party.

The AES shall keep all customer-specific information supplied by the Company confidential unless the AES has the customer's written authorization to do otherwise.

(Continued on Sheet No. E-30.00)

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

(Continued From Sheet No. E-29.00)

15. COMPANY'S LIABILITY

In addition to the Company's liability as set forth in the Company's Terms and Conditions of Open Access Distribution Service, the following shall apply. The Company will use reasonable diligence in delivering a regular and uninterrupted supply of energy to the customer, but does not guarantee uninterrupted service. The Company shall not be liable for damages for interrupting service to any customer whenever, in the judgment of the Company, such interruption is necessary in order to prevent or limit any instability or disturbance on the electric system of the Company or any electric system interconnected with the Company, such interruptive action to be taken in accordance with predetermined plan and only in situations that threaten massive curtailments of service on the Company's system. The Company shall not be liable for damages in case such service should be interrupted or fail by reason of an act of God, the public enemy, accidents, labor disputes, or orders or acts of civil authority. Further, the Company shall not be liable for damages in case such service should be interrupted due to causes or conditions beyond the Company's reasonable control. The Company shall not be liable for damages in case such service to the customer should be interrupted by failure of the customer's AES to provide appropriate energy to the Company for delivery to the customer. The Company shall not be liable for any damages, financial or otherwise, to AESs resulting from an interruption of service.

16. ALTERNATIVE ELECTRIC SUPPLIER'S LIABILITY

In the event of loss or injury to the Company's property through misuse by, or negligence of, the AES or the AES's agents and employees, the AES shall be obligated and shall pay to the Company the full cost of repairing or replacing such property.

Unless authorized by the Company to do so, an AES and its agents and employees shall not tamper with, interfere with, or break the seals of meters or other equipment of the Company installed on the customer's premises, and, under any circumstances, the AES assumes all liability for the consequences thereof. The AES agrees that no one, except agents and employees of the Company, shall be allowed to make any internal or external adjustments to any meter or other piece of apparatus that belongs to the Company.

**ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA**

**EFFECTIVE FOR SERVICE RENDERED ON
AND AFTER**

**ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370**

PJM Net Cone	\$ 288.95 /MW-Day
2018/2019 Planning Year Resources	4,948 MW
Total Company Capacity Revenue Requirement	\$ 521,849,479
Michigan Production Demand Jurisdictional Factor	14.42%
Michigan Capacity Revenue Requirement	\$ 75,253,774

Michigan Public Service Commission
Indiana Michigan Power Company - Michigan
Rate Realignment Surcharge Schedule

MPSC Case No. U-18370
ATTACHMENT D

<u>Year-x Rate (¢/kWh)</u>	<u>Year 1</u>	<u>Year 2</u>	<u>Year 3</u>	<u>Year 4</u>	<u>Year 5</u>	<u>Year 6</u>	<u>Year 7</u>
RS	0.0458	0.0383	0.0315	0.0254	0.0186	0.0112	0.0030
GS	0.0433	0.0362	0.0298	0.0240	0.0176	0.0106	0.0028
LGS	0.0303	0.0253	0.0208	0.0168	0.0123	0.0074	0.0020
LP	0.0252	0.0211	0.0174	0.0140	0.0103	0.0062	0.0016
MS	0.0396	0.0331	0.0272	0.0219	0.0161	0.0097	0.0026
WSS	0.0298	0.0249	0.0205	0.0165	0.0121	0.0073	0.0019
EHS	(1.5364)	(0.4680)	0.0294	0.0236	0.0173	0.0104	0.0028
IS	(10.3552)	(9.1078)	(7.7356)	(6.2262)	(4.5658)	(2.7394)	(0.7304)
OSL	0.1010	0.0844	0.0695	0.0560	0.0410	0.0246	0.0066
SL	0.0596	0.0498	0.0411	0.0330	0.0242	0.0145	0.0039

PROOF OF SERVICE

STATE OF MICHIGAN)

Case No. U-18370

County of Ingham)

Lisa Felice being duly sworn, deposes and says that on April 12, 2018 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

Subscribed and sworn to before me
this 12th day of April 2018



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

Service List for Case: U-18370

Name	Email Address
Bryan A. Brandenburg	bbrandenburg@clarkhill.com
Celeste R. Gill	gillc1@michigan.gov
Indiana Michigan 1 of 3	ajwilliamson@aep.com
Indiana Michigan 2 of 3	msmckenzie@aep.com
Indiana Michigan 3 of 3	mgobrien@aep.com
Mark Cummins	cumminsm1@michigan.gov
Michael J. Pattwell	mpattwell@clarkhill.com
Richard J. Aaron	raaron@dykema.com
Sean P. Gallagher	sgallagher@clarkhill.com
Spencer A. Sattler	sattlers@michigan.gov