OFFICIAL EXHIBITS

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN RATE ADJUSTMENT; AND FOR APPROVAL OF RELATED RELIEF INCLUDING: (1) REVISED DEPRECIATION RATES; (2) ACCOUNTING RELIEF; (3) INCLUSION OF CAPITAL INVESTMENT; (4) RATE ADJUSTMENT MECHANISM PROPOSALS; (5) CUSTOMER PROGRAMS: (6) WAIVER OR DECLINATION OF JURISDICTION WITH RESPECT TO CERTAIN RULES; AND (7) NEW SCHEDULES OF RATES, RULES AND REGULATIONS.	)	IURC PETITIONER'S EXHIBIT NO. 15 12-20-21 AT DATE REPORTER **CAUSE NO. 45576**

PETITIONER'S SUBMISSION OF
SETTLEMENT TESTIMONY OF ANDREW J. WILLIAMSON

Indiana Michigan Power Company ("I&M" or "Petitioner"), hereby submits the settlement testimony and attachments of Andrew J. Williamson.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the foregoing was served this 19th day of November, 2021 via electronic email, hand delivery, or First Class, United States Mail, upon the following:

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DMS 21373419v1

I&M Exhibit: _____

INDIANA MICHIGAN POWER COMPANY

CAUSE NO. 45576

PRE-FILED VERIFIED TESTIMONY

OF

ANDREW J. WILLIAMSON

IN SUPPORT OF SETTLEMENT AGREEMENT

Table of Contents

TESTIMONY OF ANDREW J. WILLIAMSON IN SUPPORT OF SETTLEMENT AGREEMENT ON BEHALF OF INDIANA MICHIGAN POWER COMPANY

I. Introduction of Witness

Q1. Please state your name and business address.

My name is Andrew J. Williamson and my business address is Indiana Michigan Power Center, P.O. Box 60, Fort Wayne, IN 46801.

Q2. By whom are you employed and in what capacity?

I am employed by Indiana Michigan Power Company ("I&M") as Director of Regulatory Services.

Q3. Are you the same Andrew J. Williamson who previously filed testimony in this Cause?

Yes.

Q4. Did you substantially participate in negotiating the settlement agreements filed in this Cause?

Yes. I am a member of the I&M team that worked with the other parties in negotiating the settlement agreements filed in this Cause.

Q5. What is the purpose of your settlement testimony in this proceeding?

My testimony supports the Settlement Agreement reached among I&M, the Indiana Office of Utility Consumer Counselor ("OUCC") and nearly all intervenors, which was filed in this Cause on November 16, 2021. I refer to the parties collectively as the "Settling Parties" (and individually "Settling Party"). My testimony also supports the separate Muncie Settlement Agreement entered into by I&M and Intervenor the City of Muncie ("Muncie") to address the concern raised by Muncie in this Cause. I will explain the Settlement Agreement and the Muncie Settlement Agreement. I describe from Petitioners' perspective why both settlement agreements are reasonable and in the public interest and should be approved by the Commission.

Q6. Have all the parties joined the Settlement Agreement?

This is a settlement of all the issues among all but one of the parties in this Cause. Steel Dynamics, Inc. ("SDI"), the one party not joining the Settlement Agreement, has communicated to the Commission and the Settling Parties that SDI does not oppose the Settlement Agreement.

Q7. What is the position of the other parties regarding the Muncie Settlement Agreement?

The other parties take no position with respect to any of the issues addressed in the Muncie Settlement Agreement. This recognizes that Muncie Settlement Agreement has no rate impact and does not otherwise affect any issues raised or presented in the main Settlement Agreement. Rather, the Muncie Settlement Agreement addresses a concern specific to Muncie.

Q8. On whose behalf are you testifying?

I am testifying on behalf of I&M (or "Company"). While the Settling Parties have reviewed and had an opportunity to comment on the testimony I am providing prior to its filing, I note the other Settling Parties may not agree with all opinions and explanations contained in my testimony. This is also the case with respect to I&M's view of the other Settling Parties' testimony. Neither my testimony nor testimony presented by any other Settling Party changes the substance of the Settlement Agreement.

I am authorized by all Settling Parties to inform the Commission all Settling Parties believe that: (a) the Settlement Agreement as a whole represents a reasonable resolution of all the issues in this Cause; (b) approval of the Settlement Agreement is in the public interest; and (c) all Settling Parties strongly encourage the Commission, after considering the evidence in support of the Settlement Agreement, to find the Settlement Agreement to be reasonable and in the public interest and promptly enter an order approving the Settlement Agreement in its entirety.

Q9. Are you sponsoring any attachments?

Yes. Together with OUCC witness Eckert, and Industrial Group ("IG") witnesses Dauphinais and Gorman, I co-sponsor Settling Parties' Joint Exhibit 1, which is a copy of the Settlement Agreement previously filed in this Cause. The Settlement Agreement includes the following attachments:

- Settlement Agreement Attachment 1 presents a revised I&M Exhibit A-1 (Required Rate Relief Summary) to reflect the Settlement Agreement.
- Settlement Agreement Attachment 2 breaks down the approximately $141 million of Rockport Unit 2 costs to be removed from I&M's proposed base rates in accordance with Section I.A.2.a. of the Settlement Agreement.
- Settlement Agreement Attachment 3 sets forth the agreed customer class allocations of the revenue requirement as agreed to in the Settlement Agreement and also shows the impact of the Settlement Agreement on riders in Phase I[1] and Phase II.[2] The last page of this attachment (pg. 4 of 4) shows the Rate IP rates agreed to by the Settling Parties.

[1] Phase I rates represent I&M's initial rates upon implementation of the Commission's Final Order.

[2] Phase II rates represent I&M's final base rates upon implementation of I&M's final Phase-in Rate Adjustment compliance filing and any changes to riders resulting therefrom.

I would note that Settlement Agreement Attachment 1 revises I&M Exhibit A-1 to reflect the development of rates in Phase I and the changes that will be reflected in Phase II. I would add that Settlement Agreement Attachments 1 and 3 reflect revenues and rates at Test-Year-end. In other words, the Attachments include I&M's forecasted test-year-end net plant additions based on the Settlement Agreement. The implementation of the Phase II rates is subject to the certification process and will reflect the lower of actual net plant in-service or the net plant in-service agreed to in settlement as of the end of the Test Year, or December 31, 2022.

I also sponsor the following additional attachments:

- Attachment AJW-1-S, which updates the capital structure at the beginning of the Test Year and the end of the Test Year.
- Attachment AJW-2-S, which summarizes I&M's depreciation rates, including the revised depreciation rates to implement Section I.A.9.a. of the Settlement Agreement wherein the Company agreed to reduce depreciation expense by $10 million.[3]
- Attachment AJW-3-S (Public), which updates Attachments JLF-2 and JLF-3 to reflect the Settlement.[4] This sets forth the customer class revenue allocation factors, and detailed base rate, rider and total bill increase by class. The confidential version of this attachment is identified as Attachment AJW-3-S (C) (confidential).

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[3] The $10 million reduction is achieved through a combination of reduced depreciation rates and reductions to depreciable plant.

[4] These attachments were included with Company witness Fischer's direct testimony.

- Attachment AJW-4-S, which updates the typical bill comparison using Phase I rates (previously provided as Attachment JLF-4) to reflect the Settlement Agreement.
- Attachment AJW-5-S, which provides the forecasted test-year-end net plant balance used to calculate the Phase II rates.
- Attachment AJW-6-S, which is Exhibit A-8 (Gross Revenue Conversion Factor) and was unchanged by the Settlement Agreement.
- Attachment AJW-7-S, which updates Exhibit A-9 (Effective Federal Income Tax Rate) for the Settlement Agreement.
- Attachment AJW-8-S, which is a copy of Appendix G from IRS Internal Revenue Bulletin No. 2021-1.
- Attachment AJW-9-S, which updates Attachment KCC-1 (included with Company witness Cooper's direct testimony), is a complete copy of the introductory sections of the proposed Tariff Book, including the Table of Contents and Terms and Conditions of Service sections with changes reflecting the Settlement Agreement shown in redline.
- Attachment AJW-10-S, which updates Attachment KCC-2 (included with Company witness Cooper's direct testimony), is a complete copy of I&M's Tariffs and Riders sections of the proposed Tariff Book 19 with changes from the Settlement Agreement shown in redline.
- Attachment AJW-11-S, which is a copy of the Muncie Settlement Agreement.

Q10. Has I&M provided workpapers supporting the Settlement Agreement?

Yes, I&M has updated relevant cost of service and rate design workpapers to reflect the Settlement Agreement and provided these electronic spreadsheets separately. The Company's settlement workpapers are identified as:

- Confidential WP-JLF-4-S Rate Design - Settlement.
- WP IM JCOSS-CCOSS TYE 12_31_22_End of Period_Settlement.
- WP Phase-in COS, Adjustments, Rev Req, and Rate Design- Settlement.
- WP Proposed Rider Rev Rqmt and Rate Design-Settlement.

Q11. Were the attachments you are sponsoring prepared or assembled by you or under your direction and supervision?

Yes, the attachments were prepared or assembled by me with the assistance of other I&M subject matter experts.

II. Overview of Settlement Agreement

Q12. Please generally describe the Settlement Agreement.

The Settlement Agreement resolves all pending issues. Section I.A. sets forth the negotiated terms and conditions. Section II. of the Settlement Agreement addresses the presentation of the Settlement Agreement to the Commission. Section III. addresses the effect and use of the Settlement Agreement. Taken as a whole, the Settlement Agreement represents the result of arm's-length negotiations by a diverse group of stakeholders with differing views on the issues raised in the docket.

Party experts were involved with legal counsel in the development of both the conceptual framework and the details of the Settlement Agreement. Many hours were devoted by the Settling Parties to discussions, the collaborative exchange of information, and settlement negotiations. The discussions commenced early and were conducted on a parallel track to the filing of the consumer party testimony and the Company's rebuttal.

These discussions, while challenging, provided I&M an opportunity to delve into the concerns, ideas and interests of the other Settling Parties. I&M appreciates the significant time the other Settling Parties devoted to understanding the Company's perspectives and objectives relevant to the ongoing provision of retail service to our customers. Likewise, I&M devoted significant time to understanding the perspectives and objectives of the other Settling Parties. Ultimately, the efforts of the Settling Parties allowed us to reach an uncontested and balanced Settlement Agreement that fairly resolves all the issues in this case, including the Rockport Unit 2 ratemaking matters to be addressed in this proceeding as agreed to in the settlement agreement from Cause No. 45546.

The Company's case-in-chief supported a revenue deficiency of approximately $73 million in Phase I and $104 million in Phase II. The Settlement Agreement Attachment 1 (Summary of Rate Relief) provides for a Phase I revenue decrease of approximately $78 million and Phase II revenue decrease of approximately $199 million, resulting in an overall rate reduction of $(5) million in Phase I and an overall rate reduction of $(95) million in Phase II.

While this rate change is significantly less than we requested, the Company views the Settlement Agreement as a reasonable resolution of the issues in this Cause and those related to the settlement agreement pending the Commission's approval from Cause No. 45546.

Taken as a whole, the Settlement Agreement represents the result of arm's-length, indeed challenging, negotiations by a diverse group of stakeholders with differing views on the issues raised in the docket. It is my opinion that the Settlement Agreement is in the public interest and reasonably resolves all issues in this docket without further expenditure of the time and resources of the Commission and the Settling Parties in the litigation of these matters.

Q13. How is the Settlement Agreement organized?

Section I.A. of the Settlement Agreement addresses I&M's Test Year revenue requirement and other matters. Section I.B. of the Settlement Agreement sets forth the Settling Parties' agreement regarding revenue allocation, rate design and certain tariff language changes. Section I.C. addresses remaining issues - namely that any matters not addressed by the Settlement Agreement terms will be adopted as proposed by I&M. I discuss the Settlement Agreement terms specifically below. However, it is important to recognize that the Settlement Agreement is presented as a complete negotiated package of terms that, taken as a whole, reflects compromise and the give and take of negotiations.

III. Discussion of Settlement Agreement Terms

Section I.A.1.

Q14. Please discuss Section I.A.1. of the Settlement Agreement (Return on Equity, Capital Structure and Rate of Return).

Section I.A.1. of the Settlement Agreement resolves the contested issues regarding return on equity, capital structure (including the treatment of the Net Operating Loss Carryforward ("NOLC")) and overall rate of return. This section also sets out the agreement regarding the Company's Tax Rider. I discuss each of these items separately below.

ROE

Q15. Please discuss the agreed return on equity set forth in Section I.A.1. of the Settlement Agreement.

The Settling Parties agree to a Commission authorized return on equity ("ROE") of 9.70%. This compromise ROE is within the range of evidence presented by the Parties. It is the same ROE that the Commission concluded to be fair and reasonable under the totality of the circumstances in the March 11, 2020 Order (p. 41) in Cause No. 45235 (the Company's last basic rate case).[5]

Capital Structure - NOLC

Q16. Please discuss the agreement regarding Capital Structure set forth in Section I.A.1. of the Settlement Agreement.

This section of the Settlement sets out a reasonable path forward to resolve the dispute regarding the treatment of the Company's NOLC.

The NOLC is addressed in this section because it affects the calculation of accumulated deferred federal income taxes ("ADFIT") and ADFIT is included as cost free capital in the capital structure. This issue arose because I&M discovered during the preparation of this case what I&M and its outside advisors believe is a normalization inconsistency, which if not remedied would constitute a normalization violation.[6] Under the Internal Revenue Code ("IRC") safe harbor rules, this case is the "Next Available Opportunity" to correct this and avoid a normalization penalty.[7] The Company's understanding is that the NOLC needs to be accounted for in the ADFIT balance as a deferred tax asset ("DTA") to comply with the Internal Revenue Service ("IRS") normalization rules. Therefore, the Company's filing included the NOLC DTA as part of the ADFIT to correct what the Company believes is an inconsistency to avoid a violation of the IRS normalization rules.[8] This approach has the effect of reducing the amount of cost free capital included in the capital structure.

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[5] I refer to this order herein as the 45235 Order.

[6] Company witness Criss Rebuttal, at 7.

[7] *Id.*

[8] *Id.* at 14-15.

Certain consumer parties contested the Company's conclusion regarding the normalization rules due to, among other things, the Company having received certain payments from AEP.[9]

To resolve this issue, the Settling Parties have agreed that I&M will retain the approximately $159 million in cost free capital that the Company had proposed to be removed per I&M's proposed NOLC adjustment pending receipt of a Private Letter Ruling ("PLR") from the IRS. The Settlement sets forth the parties' agreement regarding the PLR request in Section I.A.1.c. and I discuss that separately below.

To avoid a normalization violation if the IRS agrees with the Company's position, it is important that the contested amounts be preserved and that the Company have the ability to timely recognize the impact in rates if the PLR confirms I&M's position. Therefore, pending receipt of an IRS PLR, the Settling Parties agreed that the Commission should authorize I&M to establish a regulatory asset for the return that would be associated with the inclusion of the proposed NOLC adjustment in the calculation of ADFIT in I&M's capital structure. The regulatory asset would also be established for the amount of any differences in I&M's requested levels of protected and unprotected[10] excess ADFIT ("EADFIT") amortization (see I.A.1.d and I.A.1.e) and the settled levels of amortization. The accrual of this regulatory asset will have an effective date equal to the effective date of the rates being implemented in this proceeding.

If the IRS PLR determines that failure to reinstate the proposed NOLC ADFIT in the calculation of I&M's capital structure constitutes a normalization violation, I&M will initiate a limited proceeding to update I&M's Tax Rider to reflect the NOLC adjustments, along with any Commission-approved offsets, in rates on an ongoing basis and to recover the regulatory asset. I&M expects that it would implement this through a Tax Rider filing.

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[9] *Id.* at 7-9 (referring OUCC witness Garrett, IG witness Gorman and Jt. Municipals' witness Cannady).

[10] Also commonly referred to as "normalized" and "non-normalized" EADFIT.

The Settling Parties have reserved their rights to take any position in the limited proceeding related to the NOLC and the Company's proposed ratemaking related thereto. All parties reserve rights to take any position regarding the Company's continued participation in the Tax Sharing Agreement on a going forward basis in the Company's next general rate case.

The proposed resolution of this issue recognizes that the IRS PLR process exists to allow the IRS to rule on matters regarding its own tax rules and reasonably balances the need for compliance with the IRS normalization rule with the ratemaking process.

Q17. What happens if the IRS PLR determines there is no normalization violation created by the failure to reinstate the NOLC ADFIT?

In this event, the Settlement Agreement provides that the regulatory asset will be written-off and will not be requested for recovery in rates. See Section I.A.1.iii.

Q18. Please discuss the process agreed to by the Settling Parties in Section I.A.1.c. regarding the PLR request.

The Settling Parties negotiated a process that will allow the Settling Parties to have an opportunity to review the PLR request before it is submitted to the IRS and to be notified of any IRS requests for further information. More specifically, the Settlement Agreement provides that the Settling Parties agree that the IRS rules regarding normalization PLR requests contained in Appendix G of Internal Revenue Bulletin 2021-01,[11] provide regulatory commissions and other interested parties certain participation rights in the PLR process. By agreeing to the terms of this Settlement the Settling Parties do not intend to limit the rights of

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[11] Revenue Procedure 2021-01 is published in Internal Revenue Bulletin 2021-01, available at https://www.irs.gov/irb/2021-01_IRB. The rules relating to PLR requests involving normalization matters are located on page 103 of Internal Revenue Bulletin 2021-01. Appendix G is included with my testimony as Attachment AJW-8-S.

the IURC, other interested parties or other noncompany Settling Parties from participating, to the extent allowed under the IRS rules.

The Settling Parties recognize that AEP has already initiated the PLR process for affiliates in other states. To the extent an AEP affiliate receives a PLR from the IRS on this issue before I&M, I&M will provide a copy of the affiliate PLR subject to a non-disclosure agreement within ten (10) business days. I&M will provide a confidential draft of the I&M PLR to the noncompany Settling Parties and will confer on a neutral description of the facts and Settling Parties' positions in the PLR request to objectively frame the issue while adhering to IRS guidelines and requirements contained in Revenue Procedure 2021-01 before the PLR request is submitted to the IRS for resolution. The noncompany Settling Parties shall provide feedback to I&M on the draft PLR no later than five (5) business days after receiving the PLR draft. I&M will convene a virtual meeting to discuss the feedback on the sixth business day following transmittal to the other Settling Parties.

As the signatory to the PLR, I&M shall make the final determination of the contents of the PLR and will also make good faith efforts to incorporate timely, reasonable feedback from the noncompany Settling Parties. The Settling Parties retain their rights to communicate with the IRS regarding the PLR as set forth in Internal Revenue Bulletin 2021-01 at page 103. See Attachment AJW-8-S (highlighted excerpt on page 103).

Should the IRS request additional information related to the PLR request, the Settlement Agreement provides that the Company shall provide the noncompany Settling Parties with timely, meaningful notice of the IRS request for additional information before a response is due, and provide a copy of the Company's response once it has been made.

The Settlement Agreement provides that the Company will file notice of the results of the ruling with the Commission and notify the Settling Parties within ten (10) business days of receipt of the PLR.

The Settlement Agreement states that no Settling Party shall be deemed to have waived any position in a subsequent case as to whether I&M may recover the costs it incurs associated with the PLR Request.

Finally for purposes of permitting the Commission to make the necessary findings consistent with the terms of this Settlement Agreement, I&M will waive confidential treatment of (1) the fact of its request for a PLR and (2) the overall results of the PLR.

Q19. Will the revenue requirement be adjusted to reflect the deferred tax expense offset for the NOLC?

Yes, Section I.A.1.f. provides that the revenue requirement will be reduced by $5,914,719 (Total Company), $3,327,861 (Indiana Jurisdictional), to reflect the protected EADFIT impact to deferred tax expense for the NOLC.

Tax Rider

Q20. What have the Settling Parties agreed to regarding the Company's Tax Rider?

The 45235 Order, p. 74, authorized I&M to implement the Tax Rider to address the ongoing rate impacts of the 2017 Tax Cuts and Jobs Act ("TCJA"). The Tax Rider allows for a smooth sun setting of the final amortization of unprotected EADFIT credit that resulted from the TCJA. The Company also proposed to use the Tax Rider to address future changes in corporate federal income tax rates. Certain consumer parties objected to this latter use of the Tax Rider.[12]

In the Settlement Agreement, the Settling Parties agreed that the Tax Rider will serve only two purposes: (1) to credit customer rates for the remaining benefits associated with unprotected EADFIT as defined in this Settlement Agreement

[12] Company witness Ross rebuttal at 19, 22 (referring to Jt. Municipal witness Cannady (p. 19) and OUCC Witness Blakley (pp. 14-15)).

and (2) to implement ratemaking adjustments associated with an IRS PLR that requires I&M to make its proposed NOLC adjustment.

More specifically, simultaneous with the implementation of new base rates, I&M will implement a Tax Rider to credit customer rates for the remaining benefits associated with unprotected EADFIT. The Settling Parties also agreed to increase the amount of monthly amortization. This agreement will advance the benefit of this amortization to customers and as a result the amortization credit in the Tax Rider is expected to expire before the end of the Test Year.

Also, for purposes of setting rates in this proceeding for the Tax Rider, I&M agreed not to adjust the remaining balance of unprotected EADFIT for any NOLC impact. I&M also agreed to a $14,623,272 (Indiana Jurisdictional) EADFIT credit as proposed by Joint Municipal witness Cannady and a seven (7) month amortization period. The total monthly EADFIT amount to be credited to customers will include a carrying charge on the unamortized balance based on the pre-tax Weighted Average Cost of Capital ("WACC") approved in this proceeding. In addition, the monthly amortization will be grossed up for taxes at a rate of 1.3580 and will include carrying charges on the unamortized balance based on I&M's pre-tax WACC approved in Settlement. The Settling Parties agreed that I&M will reconcile the Tax Rider to reflect its actual unprotected EADFIT amortization and monthly remaining balance.

Capital Structure – Debt/Equity Ratio

Q21. Please discuss the agreement in Section I.A.1.e.

This section of the Settlement Agreement resolves a concern regarding the Company's Debt/Equity ratio. While Company witness Bulkley testified that the ratio is reasonable, Mr. Gorman challenged the forecasted change in the ratio.[13]

[13] Company witness Bulkley Direct at 77-78; Rebuttal at 67-68; IG witness Gorman at 129-130.

To resolve this concern, the Settling Parties agreed that for purposes of calculating the Phase-In Rate Adjustment for Phase I rates, the Debt/Equity ratio for investor-supplied capital will be 50.54%/49.46%. For purposes of the Phase II compliance filing, the Debt/Equity ratio for investor-supplied capital will be adjusted to the 12/31/22 actual ratio, but no higher than a 50.00% equity ratio. Attachment AJW-1-S (which updates Exhibit A-7) sets for the settlement Weighted Average Cost of Capital and Cost of Investor Supplied Capital for both Phase I and Phase II.

The Phase II ratemaking capital structure (after-tax) is presented below.

Figure AJW-1. Phase II Ratemaking After-Tax Capital Structure

Description	Total Company Capitalization $	Percent of Total	% Cost Rate	% Weighted Avg. Cost Rate
Long-Term Debt	2,873,862,352	40.70%	4.44%	1.81%
Common Equity	2,873,862,352	40.70%	9.70%	3.95%
Customer Deposits	41,698,455	0.59%	2.00%	0.01%
Acc. Def. FIT	1,257,846,893	17.81%	0.00%	0.00%
Acc. Def. JDITC	13,678,705	0.19%	7.07%	0.01%
Total	7,060,948,756	100.00%		5.78%

Net Operating Income (NOI)

Q22. What is the authorized net operating income under the Settlement Agreement?

The authorized base rate net operating income will be $296,733,906 as summarized below (Settlement Agreement Attachment 1).

Figure AJW-2. Settlement NOI

		(in dollars)
Income Requirement	$	296,288,136
Remove Transmission Owner Costs, Revenues	$	605,355
Gross Revenue Conversion Factor		1.3580
After Tax	$	445,770
Total Base Rate Net Operating Income	$	296,733,906

Section I.A.2.

Q23. Please discuss Section I.A.2. of the Settlement Agreement (Rockport Unit 2 Costs).

My direct testimony addressed the treatment of Rockport Unit 2-related matters as a result of the termination of the Rockport Unit 2 lease (Lease) on December 7, 2022.[14] Subsequent to the filing of the Company's case-in-chief, I&M and the other parties in Cause No. 45546 entered into a settlement agreement regarding the treatment of the Rockport Unit 2 costs after the end of the Lease. In his testimony, Industrial Witness Gorman calculated that approximately $129 million of Rockport Unit 2 related costs should be removed from the revenue requirement in the Phase II rates.[15] In my rebuttal testimony, I presented that the amount is approximately $141 million.

In the Settlement Agreement, the Settling Parties agreed to remove from I&M's rates approximately $141 million of Rockport Unit 2 costs upon the end of the Lease (i.e. December 7, 2022) and to a process to achieve this efficiently. The Settlement Agreement includes a summary of the $141 million of Rockport Unit 2 costs in Settlement Attachment 2. The efficient process to implement this

[14] Williamson Direct at 4, 15-22; also Williamson Rebuttal, at 2-13.

[15] IG witness Gorman, at 4.

change is what the Settlement Agreement refers to as the "PRA Rockport Charge". I step through these provisions in more detail below.

The Settlement Agreement also addresses the removal of Rockport Unit 2 costs from rates via the relevant tracking mechanisms and I discuss this further below.

Q24. Please further explain the agreed ratemaking treatment for the removal of the Rockport Unit 2 costs from the revenue requirement.

Section I.A.2. provides that approximately $141 million of Rockport Unit 2 costs will be removed from the base rate revenue requirement at the time new base rates are implemented (Phase I). Upon implementation of new Phase I base rates, I&M will simultaneously implement a temporary charge through its PRA (i.e. the "PRA Rockport Unit 2 Charge"), by which I&M will continue to recover the costs and expenses associated with Rockport Unit 2 that will not be tracked in other riders.

More specifically, when I&M implements new base rates (Phase I) it will simultaneously implement the PRA which will be computed based on two credits and one charge. The two credits are unrelated to the Rockport Unit 2 costs and are discussed in more detail later in my testimony. The charge is to continue recovering Rockport 2-related costs through the end of the Lease, or December 7, 2022. The PRA will be adjusted during the Test Year to remove the PRA Excluded Capacity Credit and PRA Rockport Unit 2 Charge according to the terms of the Settlement Agreement.

The Settling Parties developed this process because it more efficiently allows for the removal of the Rockport Unit 2 costs from base rates.

Q25. When will the PRA Rockport Unit 2 Charge expire?

The PRA Rockport Unit 2 Charge will expire on December 8, 2022 on a service-rendered basis and will not be subject to true-up or further reconciliation. In the event I&M determines that the PRA Rockport Unit 2 Charge has resulted in full recovery of the Rockport Unit 2 costs identified by type and amount below before December 8, 2022, I&M has agreed to cease collection of the PRA Rockport Unit 2 Charge.

Q26. What will the PRA Rockport Unit 2 Charge include?

Per Section I.A.2. of the Settlement Agreement, the PRA Rockport Unit 2 Charge will include the following:

i. A return on a fixed $15,143,223 (Indiana Jurisdictional) level of fuel and consumables inventory through December 7,2022 at I&M's Phase I WAAC grossed up for taxes.

ii. I&M will recover the prorated share of a fixed $1,035,878 (Indiana Jurisdictional) annual level of fuel handling and disposal expenses through December 7, 2022.

iii. I&M will recover its Rockport Unit 2 lease expense incurred through the end of calendar year 2022, based on the prorated share of I&M's annual $48,924,630 (Indiana Jurisdictional) lease expense. Since the PRA Rockport Unit 2 Charge will end on December 8, 2022, I&M's Rockport Unit 2 Lease expense will be grossed up to recognize the full lease expense in 2022[16] for purposes of setting the PRA Rockport Unit 2 Charge.

iv. I&M will recover the prorated share of a fixed $13,240,324 (Indiana Jurisdictional) annual level of other operations and maintenance ("O&M") expense ($12,177,941) and property tax expense ($1,062,383) through December 7, 2022.

v. Revenue requirement for implementing the PRA Rockport Unit 2 Charge will be allocated and retail rates designed based on agreement of the parties.

This approach allows the removal of the Rockport Unit 2 costs from the revenue requirement in a reasonable and efficient manner. Among other things, the use

[16] For accounting purposes, even though the Lease ends on December 7, 2022, I&M's and AEG's Lease expense is spread over 12 months and recorded throughout the entire calendar year.

of the PRA Rockport Unit 2 Charge avoids the need for the Company to prepare, and all the parties and the Commission to review and process two complete sets of tariffs and associated compliance support. It is an efficient and transparent approach for the timely removal of these costs from base rates while maintaining recovery of these costs during the term of the Lease.

Q27. How will I&M revise the PRA to remove the PRA Rockport Unit 2 Charge?

Upon the earlier of I&M determining it has fully recovered the PRA Rockport Unit 2 Charge or December 7, 2022, I&M will submit a compliance tariff to the Commission in the Cause No. 45576 docket to eliminate the PRA Rockport Unit 2 Charge from the PRA factors. Since this change will be fully eliminating this component, and the impact to the PRA is limited to the math associated with removing this component of the PRA factors, I&M asks the Commission to expeditiously approve the revision.

Q28. Please discuss Section I.A.2.c. of the Settlement Agreement, which concerns I&M's Environmental Cost Rider (ECR) and Resource Adequacy Rider (RAR).

This section provides that upon implementation of new Phase I base rates, I&M will simultaneously implement new ECR and RAR rates to continue recovering the Rockport Unit 2 costs and expenses currently recovered through those riders through the term of the Lease.

Under the Settlement Agreement, I&M will make a filing in 2022 to revise its ECR and RAR rates effective with the first billing cycle in January 2023 to exclude the Rockport Unit 2 ECR and RAR costs that are no longer recoverable after the end of the Lease. The timing of the 2023 ECR and RAR rate changes will be dependent upon a Commission order allowing new rates to be implemented.

The Settlement Agreement clarifies the Rockport Unit 2 related cost components of the ECR and RAR factors will be as follows:

1) The ECR rates that are implemented at the time new Phase I base rates are implemented will include I&M's estimated Consumables Expenses and Allowances Expenses shown on Settlement Attachment 1. The ECR will be reconciled to actuals consistent with current ECR practices such that I&M will only recover its actual Rockport Unit 2 consumables and allowances costs incurred through December 7, 2022.

2) The RAR rates that are implemented at the time new Phase I base rates are implemented will include I&M's estimated AEG UPA – Non-Fuel Expenses shown on Settlement Attachment 1. The RAR will be reconciled to actuals consistent with current RAR practices such that I&M will only recover its actual Rockport Unit 2 AEG bill expenses incurred through December 7, 2022. This provision allows for full recovery of AEG's actual remaining Rockport Unit 2 lease expense incurred through the end of calendar year 2022.[17]

Thus, the Settling Parties have identified the costs that will be removed from base rates while maintaining recovery of these costs during the term of the Lease and an efficient process for implementing that agreement.

Q29. Please discuss the Section I.A.2.d. of the Settlement Agreement (Fuel).

This section addresses the treatment of Rockport Unit 2 costs in I&M's fuel cost adjustment ("FAC") proceedings and sets out the base cost of fuel.

The Settling Parties agreed that I&M will recover its actual Rockport Unit 2 FAC-eligible fuel expenses, consistent with current FAC cases, incurred through December 7, 2022. I&M's base cost of fuel will include $28,185,922 (Total

[17] See footnote 16.

Company), $19,608,596 (Indiana Jurisdictional), in embedded Rockport Unit 2 fuel costs, which will serve as a proxy for replacement purchased power when Rockport Unit 2 is no longer used for retail energy needs. This amount is incorporated into I&M's fuel basing points of 13.110 mills per kWh,[18] which will be reconciled to actual fuel costs in I&M's FAC proceedings. Continuing to include Rockport Unit 2 fuel expense in I&M's FAC basing point recognizes that at times I&M will have to purchase power from PJM and allows for a basing point that reasonably recognizes the amount of energy that may be needed to serve customers.

Section I.A.3.

Q30. Please discuss the Section I.A.3. of the Settlement Agreement (Remaining Rockport Unit 2 Net Book Value at December 7, 2022).

This section reasonably resolves the differing views on the recovery of the remaining Rockport Unit 2 Net Book Value at the end of the Lease by identifying the negotiated amount that is recoverable and agreeing to have such recovery occur on a levelized basis as follows:

When I&M makes its PRA compliance filing to implement final base rates (i.e. Phase II) I&M will adjust the PRA to reflect the removal of the remaining NBV of Rockport Unit 2 of $77,687,384 (Indiana Jurisdictional) from rate base. At that time and going forward through December 31, 2028, I&M will be permitted to recover a total of $95,639,514 (Indiana Jurisdictional) associated with the NBV of Rockport Unit 2, on a levelized basis in I&M's ECR (or alternative rate adjustment mechanism if the ECR is discontinued in the future).[19]

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[18] Company witness Heimberger Direct Attachment NAH-8. Also see Fuel Cost Adjustment Rider in Attachment AJW-10-S.

[19] Settlement Agreement, Section I.A.3.; see Company witness Williamson Rebuttal, at 3, 8-12 for discussion of the contested issue with the OUCC regarding the return of and on the remaining net book value; Company witness Williamson Rebuttal at 12 for discussion of Industrial Group's proposal regarding levelized cost recovery.

The final PRA compliance filing made in January 2023 will result in final PRA tariff rates that will be applicable until I&M implements new base rates in its next general rate case.

Section I.A.4.

Q31. Please discuss the Section I.A.4. of the Settlement Agreement (Jurisdictional Reallocation).

The pre-filed evidence reflects the dispute regarding the treatment of the excluded capacity from Cause No. 45235. The OUCC, IG, and Joint Municipals took the position that the adjustment ordered by the Commission in Cause No. 45235, or some version of that adjustment, should continue at least until the Rockport Unit 2 lease ends on December 7, 2022, at which point I&M will no longer have the "excess capacity" that supported the Commission's prior decision.[20] My rebuttal testimony explained that the Company's need to meet its PJM capacity obligation is as of June 1, 2022.[21] The PJM market requires capacity resources that are available for the entire PJM Planning Year ("PY"), which runs from June 1 through May 31 -- meaning a capacity resource which is only available through part of a PY would not be able to be used or sold as a capacity resource in PJM.[22]

My rebuttal testimony also explained that the date by which the Company must satisfy its capacity shortfall (June 1, 2022), is exactly halfway through the projected Test Year and approximately one month after I&M expects to implement new base rates approved by the Commission in this Cause.[23]

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[20] See OUCC witness Boerger, at 7; IG witness Gorman, at. 51, 56. See also Jt. Municipals witness Mancinelli, at 18-19 (proposing adjustment consistent with prior ruling on this issue).

[21] Company witness Williamson Rebuttal at 16.

[22] *Id.*

[23] *Id.* at 15.

The negotiated settlement package, resolves this issue by I&M agreeing to temporarily reflect in ratemaking the effect of the excluded capacity from Cause No. 45235 for the period beginning with the implementation of new base rates (Phase I) in this Cause through December 7, 2022 through the proposed PRA Excluded Capacity Credit.

Q32. How will the PRA Excluded Capacity Credit be calculated and implemented?

I&M agreed to implement Phase I rates and simultaneously implement a temporary PRA Excluded Capacity Credit to credit customers for excluded capacity costs consistent with the Commission's Final Order in Cause No. 45235; the credit will be eliminated from the PRA on a service rendered basis effective December 8, 2022.

The credit will be developed based on a monthly amount of $4,702,533 offset by the fixed annual level of retained capacity and Off System Sales revenues of $24,926,096, prorated to a monthly level of $2,077,175, for a net monthly credit of $2,625,358.

Q33. How will I&M revise the PRA to remove the PRA Excluded Capacity Credit?

I&M will submit a compliance tariff to the Commission in the Cause No. 45576 docket to eliminate the PRA Excluded Capacity Credit from the PRA factors. Since this change will be fully eliminating this component, and the impact to the PRA is limited to the math associated with removing this component of the PRA factors, I&M asks the Commission to expeditiously approve the revision.

Section I.A.5.

Q34. Please discuss the Section I.A.5. of the Settlement Agreement (PJM NITS Costs).

This section of the Settlement Agreement balances the Company's need for timely cost recovery of PJM Network Integration Transmission Service ("NITS") costs with the Industrial Group's interest in understanding the investments underlying the PJM rate adjustment mechanism.[24] The negotiated compromise will mitigate rate increases between general rate cases and this in turn, in I&M's view, should help customers to better understand the going-forward cost of electricity.

The Settling Parties agreed that I&M will provide the same annual presentation to noncompany Settling Parties on a going-forward basis that has been previously provided to the utilities commission in the State of Michigan in order to provide additional detail regarding supplemental projects consistent with the information provided through the PJM stakeholder process.

An annual cap will be placed only on the PJM NITS costs recorded to FERC accounts 4561035 and 5650016 and recovered through the Off-System Sales/PJM Rider ("OSS/PJM") at I&M's Indiana Jurisdictional amount forecasted for 2024 plus 15%, which totals $381.3 million (Indiana Jurisdictional). These are the same FERC accounts that were reflected in the settlement agreement approved in Cause No. 44967. If annual NITS costs recorded to FERC accounts 4561035 and 5650016 exceed $381.3 million in any year, I&M will defer to a regulatory asset the revenue requirement associated with the excess amount, including ongoing carrying costs at the pre-tax WACC, for recovery in I&M's next base rate case. The remaining NITS costs up to the annual cap level will continue to be recovered through I&M's OSS/PJM Rider, all other costs and revenue credits will be included in the OSS/PJM Rider as proposed by I&M.

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[24] See rebuttal testimony of Company witness Seger-Lawson (p. 9-20) for discussion of this contested issue.

Section I.A.6.

Q35. Please discuss the Section I.A.6. of the Settlement Agreement (AMI).

While the consumer parties did not oppose the Company's proposal to transition away from AMR to AMI infrastructure, the OUCC and Joint Municipals opposed the Company's proposed AMI Rider.[25] The Industrial Group raised concerns with both the lack of specificity as to how costs would be allocated and the cost of service implications of the Company's proposal to recover costs through demand and energy charges.[26] In the Settlement Agreement, the Settling Parties agreed to include I&M's capital forecast period (2021-2022) AMI capital ($54.649 million) and O&M costs ($4.77 million) in base rates set in this Cause. I&M agreed to withdraw it's request for an AMI rider. The Settlement Agreement makes clear that I&M is not prevented from seeking recovery of additional AMI investment and operating and maintenance ("O&M") costs in its next base rate case(s). The noncompany Settling Parties agree not to challenge the reasonableness of I&M's decision to transition from AMR meters to AMI meters or the reasonableness of I&M's four-year deployment plan, as presented in this Cause, in any future proceeding. This agreement resolves the AMI deployment question and provides a reasonable level of ratemaking support and assurance to allow the Company to proceed with its AMI program.

Section I.A.7.

Q36. Please discuss the Section I.A.7. of the Settlement Agreement (OPEB/Pre-Paid Pension Asset).

The pre-filed testimony outlines the dispute among the parties regarding the Prepaid Pension and Other Post-Retirement Employee Benefit ("OPEB") assets. I&M proposed to continue to include the prepaid pension asset in rate base

[25] See Rebuttal testimony of Company witness Seger-Lawson, at 2-8.

[26] See Verified Direct Testimony of Industrial Group witness Dauphinais at 37-38.

consistent with the Commission's past decisions. The Company also proposed to include its prepaid OPEB asset in rate base and provided historical support and other evidence to support this ratemaking. The OUCC and Industrial Group opposed the inclusion of these assets in rate base. I&M's witness Ross presented rebuttal on these matters.[27]

In the Settlement Agreement, the Settling Parties agreed that rate base shall include the pre-paid pension asset in the amount of $80.7 million (Total Company), $58.1 million (Indiana Jurisdictional). The Settling Parties agreed to the removal of the $96,252,892 (Total Company), $69,324,472 (Indiana Jurisdictional), OPEB prepayment asset from rate base.

This compromise is a reasonable part of the overall negotiated settlement package.

Section I.A.8.

Q37. Please discuss the Section I.A.8. of the Settlement Agreement (Non-Rockport Unit 2 Miscellaneous Rate Base).

For the purpose of calculating the revenue requirement used to set base rates, I&M agreed to reduce its proposed rate base by $26.4 million as follows.

1) Remove $3,783,088 EV Fast Charging costs;
2) Remove $568,770 Flex Pay Program costs;
3) Remove $2,023,141 unamortized COVID-19 deferred bad debt expense; and
4) Remove $20 million of forecasted Distribution plant investment.

The Settlement Agreement clarifies that nothing in this agreement precludes I&M from seeking to include the removed items in its cost of service in a future case. In I&M's view this clarification recognizes the need for ongoing distribution

[27] Rebuttal testimony of Company witness Ross, at 5-19.

system investment while at the same time allowing I&M to reduce the impact new base rates will have on customers. Thus, the agreement also allows the Company the opportunity to revisit the EV Fast Charging and the Flex Pay Program proposals and pursue them as necessary in future proceedings. Below is a summary of I&M's rate base (Indiana Jurisdictional) as of December 31, 2022.

Figure AJW-3. Summary of Settlement Rate Base

		(in dollars)
Net Plant In-Service	$	4,846,054,499
Fuel Stock	$	29,521,506
Other Materials & Supplies	$	124,206,512
Allowance Inventory	$	17,674,176
Prepaid Pension Expense	$	58,104,811
Regulatory Assets	$	49,998,924
	$	5,125,560,428

Section I.A.9.

Q38. Please discuss the Section I.A.9. of the Settlement Agreement (Expense Adjustments).

This Section provides another means of mitigating increases to consumer rates. For the purpose of calculating revenue requirements in this case, I&M agreed to reduce its proposed O&M expenses as follows.

- $10 million from depreciation expense. To implement this, the Company reduced depreciation expense through a combination of expense reductions related to the rate base reductions associated with utility plant investments discussed above and revised distribution plant depreciation rates. The OUCC's pre-filed testimony included several proposals to adjust I&M's distribution plant depreciation rates. The revised distribution plant depreciation rates include acceptance of OUCC depreciation rate proposals for certain distribution FERC plant accounts[28] (but not the methodology), a compromise of proposals made by the OUCC and the Company for certain distribution FERC plant accounts[29] and are set forth in Attachment AJW-2-S.

- $2.0 million from nuclear decommissioning. The Settling Parties agree that I&M may seek an adjustment to the funding level of the Nuclear Decommissioning Trust based on future analysis of the adequacy of the Nuclear Decommissioning Trust funds to pay for decommissioning.[30]
- $293,773 deferred COVID-19 bad debt expense. This accepts OUCC witness Blakley's proposal to reduce the incremental bad debt expense amortization by $293,773.[31] While the Company disagreed with the basis for the OUCC's proposed adjustment,[32] in the context of the overall settlement, the Company accepted this proposal as part of the goal of mitigating the impact of this case on customer rates.
- $4.0 million in other O&M in I&M's Test Year forecast. This provision recognizes that other aspects of the Company's Test Year O&M forecast were challenged. While the Company stands behind its forecasting process, in the spirit of compromise the Company agreed to a reduction in forecasted O&M in the amount of $4 million.

Finally, the Settlement Agreement clarifies that nothing in this agreement precludes I&M from seeking recovery of these type of expenses in a future case.

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28 FERC plant accounts 365, 366, and 367.

29 FERC plant accounts 364, 368, and 369.

30 See OUCC witness Eckert at 11-14; Company witness Hill rebuttal at 2-7.

31 See OUCC witness Blakley at 7.

32 See Company witness Seger-Lawson rebuttal at 29-31.

This provision reasonably reflects that the settlement is a negotiated package compromise.

Section I.A.10.

Q39. Please discuss the Section I.A.10. of the Settlement Agreement (Other).

This section addresses other issues raised by the OUCC and Intervenors. The terms and conditions in this Section fall into the following categories:

- OUCC Report in the FAC
- Vegetation Management Reporting
- Notice of Disconnection of Service
- Solar Power Rider
- Flex Pay Program
- EV Fast Charging
- Low Income Customers
- Indiana Utility Ratepayer Trust

Q40. What does Section I.A.10. of the Settlement Agreement (Other) provide regarding the OUCC report in the FAC proceedings?

I&M agreed to provide the OUCC with a 35-day review period in its FAC proceeding, starting with Cause No. 38702 FAC-89, which is expected to be filed by I&M late July 2022 or early August 2022. While I&M has disputed the need for this, the OUCC has raised the issue before.[33] Therefore, in the spirit of compromise this item was included in the settlement package.

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[33] See Rebuttal testimony of Company witness Seger-Lawson, at 20.

Q41. What does Section I.A.10. of the Settlement Agreement (Other) provide regarding Vegetation Management reporting?

I&M agreed to include vegetation management reliability statistics in its Cause No. 44967 performance metrics report. As discussed in the rebuttal testimony of Company witness Isaacson (p. 3), the Company already reports its annual level of vegetation management investment and SAIDI statistics from tree-related outages in the PMC Report. The Settlement Agreement accepts OUCC witness Eckert's proposal that the Company add to this report System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) statistics for tree-related outages.

Q42. What does Section I.A.10. of the Settlement Agreement (Other) provide regarding the notification of disconnection of service?

The Settlement Agreement addresses a concern raised regarding notification of customers at risk of disconnection of service.[34] This concern arises from the Company's deployment of AMI and its request for waiver of the Commission's disconnect rule so that the Company may use the AMI technology to disconnect and reconnect service remotely.[35]

In the Settlement Agreement I&M agreed to notify its customers of its ability to remotely disconnect/reconnect via bill insert, text, and email. This notice will identify a customer's rights prior to disconnection, including a description of the process I&M will use when attempting to contact its customers before a remote disconnection, information on how to contact I&M's customer service department and LIHEAP, and information on how to add an email address and/or mobile phone number to receive notifications from the utility.

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[34] See Rebuttal testimony of Company witness Seger-Lawson at 37-38.

[35] See Rebuttal testimony of Company witness Seger-Lawson at 35-39.

This negotiated compromise balances the consumer party interest in additional notice with the need for such communications to be issued effectively and efficiently.

Q43. What does Section I.A.10. of the Settlement Agreement (Other) provide regarding the Solar Power Rider?

I&M agreed to withdraw its request to change the name of the Solar Power Rider, and to not make related tariff language modifications. This provision resolves the concern raised by the Joint Municipals as to the purpose of the Company's proposal.[36] Because this agreement is without prejudice to seek such a name change and related tariff language modifications in a future proceeding, the Settlement Agreement mitigates controversy in the rate case while reasonably preserving the Company's right to make the proposal again in the future. For example, making such a request at such time as the Company has identified a specific project and associated cost recovery that would warrant the change of the rider name may allow the parties to have better context in which to assess the need for a change.

Q44. What does Section I.A.10. of the Settlement Agreement (Other) provide regarding the Flex Pay Program?

I&M agreed to withdraw its request to implement the Flex Pay Program without prejudice to seek approval for such a program in a future proceeding. Should I&M pursue a prepaid program such as this in the future, I&M agreed that its proposal will reflect that it will (i) not specifically market to customers facing disconnection for non-payment or customers concerned about the deposit amount required by I&M; (ii) market the program as a voluntary service; and (iii) ensure customers can purchase service credits 24 hours per day, seven-days per week via phone or internet with no transaction fees. I&M also agreed to

[36] See Rebuttal testimony of Company witness Seger-Lawson, at 8-9.

meet with interested stakeholders, including Citizens' Action Coalition ("CAC"), prior to filing the program to receive input on the development of the program, including concerns related to the winter disconnection moratorium as defined in Ind. Code Section 8-1-2-121. This resolution allows the Company to gather additional stakeholder input that may reduce or avoid controversy in a future proceeding.[37]

Q45. What does Section I.A.10. of the Settlement Agreement (Other) provide regarding the EV Fast Charging program?

I&M agreed to withdraw its request to implement the EV Fast Charging program without prejudice to seek approval for such a program in a future proceeding. This will allow I&M to further consider stakeholder input in the design of this program.

Q46. What does Section I.A.10. of the Settlement Agreement (Other) provide regarding low income consumers?

This Section of the Settlement Agreement addresses low-income customer concerns in three ways.

First, the Settlement Agreement provides I&M agreed to fund $175,000 per year in 2022 and 2023 to continue the Low Income Arrearage Forgiveness program currently in place as a result of the settlement agreement in Cause No. 44967 and to exclude these costs from I&M's cost of service. This is responsive to CAC witness Howat's proposal (p. 15) for low-income customer assistance including an arrearage management component.

The Company previously devoted considerable resources to establishing its existing Low Income Arrearage Forgiveness program. The existing program was launched in December 2019 and was intended to last for 2 years. At this time,

[37] See Rebuttal testimony of Company witness Lucas, at 18-21 for discussion of the contested issue.

the Company expects the program to end in June 2022. The settlement term is expected to extend the program for approximately two additional years. Overall, I&M feels that the existing program is performing well and is well received by customers. The program is providing customers with an opportunity to receive assistance with arrearages while supporting customers making regular payments for service.

- 187 accounts have successfully completed the entire program.
- 334 accounts started the program but did not complete the full program (received partial benefit).
- Since inception of the program, I&M has provided $331,782 of benefits to participating customers.
- As of November 1, 2021 there are $168,218 of funds remaining in the program.

The Company found common ground with CAC in Cause No. 44967 with respect to exploring the potential benefits of this type of program but the Company also recognizes that a program like this raises concerns from other stakeholders. Continuing the program without recognizing the cost in the revenue requirement will allow us to gather additional insight into the impact of arrearage forgiveness on our operations and our customers – both those that participate in the program and those that do not. In addition to this program, I&M will continue to offer its existing payment assistance programs ranging from agreements to extend a bill payment a few days to longer monthly payment programs.

Second, I&M agreed to customer deposits for customers identified as LIHEAP participants or LIHEAP-eligible to no more than $50. This recommendation was also made by CAC witness Howat (p. 23) based on the view that a large deposit assessment for new or restored service can be extremely burdensome for income qualified customers. The Settlement Agreement commitment will allow

I&M to gain additional insights regarding how to help our customers who are challenged to pay their electricity bill.

Third, I&M will provide a $150,000 contribution to the community action program network of Indiana Community Action Association to facilitate low-income weatherization in I&M's service territory, including but not limited to using funds to address health and safety issues preventing weatherization, and to assist in bill payment and deposit assistance for I&M LIHEAP eligible households. I&M's cost of service in this Cause will not be adjusted to include the incremental costs of this contribution.

Q47. What does Section I.A.10. of the Settlement Agreement (Other) provide regarding the Indiana Utility Ratepayer Trust?

I&M agreed to provide a $100,000 contribution to the Indiana Utility Ratepayer Trust. I&M's cost of service in this Cause will not be adjusted to include the incremental costs of this contribution.[38]

Section I.B.

Q48. What matters are addressed in Section I.B. of the Settlement Agreement (Cost of Service and Rate Design)?

Section I.B. of the Settlement Agreement sets forth the Settling Parties' agreement regarding revenue allocation.

Q49. Please discuss Section I.B.1. of the Settlement Agreement.

The Residential rate design issues were the subject of much testimony in this proceeding. While the Company has firmly held positions regarding the application of cost of service and cost recovery principles to residential rate

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[38] For a description of this trust see: www.in.gov/oucc/about-your-rates/indiana-utility-rate-payer-trust/ .

design we also recognize the passion around this issue reflected in the testimony offered by the residential consumer advocates. The divergence of views made this issue challenging to resolve. Ultimately, the Settling Parties agreed to small changes to the rate design approved by the Commission in the Company's last basic rate case. More specifically, the Settling Parties agreed to keep I&M's fixed monthly charge for Residential Electric Service - Tariff R.S. ("Tariff R.S.") at $15 per month. The Settling Parties also agreed the fixed monthly charge for Residential Time-of-Day Service (Tariff R.S.-TOD and Tariff R.S.-TOD2) will increase to $17 per month.

Q50. Please discuss Section I.B.2. of the Settlement Agreement.

Section I.B.2. sets forth the Settling Parties' agreement that rates should be designed in order to allocate the revenue requirement to and among I&M's customer classes in a fair and reasonable manner. For settlement purposes, the Settling Parties agree that Settlement Agreement Attachment 3 specifies the revenue allocation agreed to by all Settling Parties. The Settlement Agreement provides that this revenue allocation is determined strictly for settlement purposes and is without reference to any particular, specific cost allocation methodology.

As mentioned above, Attachment AJW-3-S (Public), which updates Attachments JLF-2 and JLF-3 to reflect the Settlement, provides additional supporting details including the customer class revenue allocation factors, and detailed base rate, rider and total bill increase by class. The confidential version of this attachment is identified as Attachment AJW-3-S (C) (confidential).

Q51. Please discuss Section I.B.3. of the Settlement Agreement (IP Rate Design).

The Settling Parties agreed to an Industrial Power - Tariff I.P. ("Tariff I.P.") rate design that produces agreed upon energy and demand charges as set out in

Settlement Attachment 3. To correspond with acceptance of the Company's proposed change in Tariff I.P. billing demands from kVA to kW, the settlement demand charges were increased to reflect the approximate average power factor (kW per kVA) for each voltage level of Tariff I.P. Consistent with this change, the reduced amount of residual demand-related costs were included in the first 410 kWh per kW energy block. This change is a reasonable alignment of the change in billing units with the change in rates.

Q52. Please discuss Section I.B.4. of the Settlement Agreement (LGS).

I&M agrees not to combine General Service - Tariff G.S. ("Tariff G.S.") and Large General Service - Tariff L.G.S. ("Tariff L.G.S.") base rates. I&M will continue to eliminate the kVA demand charge and Power Factor Correction Capacitor ("PFCC") adjustment in Tariff L.G.S. To ease the transition from full kVA billing demands, I&M agreed to implement an excess kVA charge in Tariff L.G.S. The specific language of the Excess kVA provision is as follows:

> *The monthly KVA demand shall be determined by dividing the maximum metered KW demand by the average monthly power factor. The excess KVA demand, if any shall be the amount by which the monthly KVA demand exceeds the greater of (a) 101% of the maximum metered KW demand or (b) 60 KVA. The Metered Voltage adjustment, as set forth below, shall apply to the customer's excess KVA demand.*

Finally, the rider rates for Tariffs G.S. and Tariff L.G.S. were unified to mitigate some of I&M's concerns that led to its initial proposal to combine Tariff G.S. and Tariff L.G.S.

Q53. Please discuss Section I.B.5. of the Settlement Agreement (Tariff T&C 27).

The Settling Parties agree that I&M may adopt its proposed new provision number in its Terms and Conditions as modified below:

> *27. Customer Requested Disconnection / Reconnection at Station Transformer. Whenever, at the customer's request, the Company is*

> *required to perform a disconnection and / or reconnection at a customer or Company owned station transformer, switch or breaker, the customer shall reimburse the Company for the entire cost incurred in making such connections which shall include all labor costs, transportation and equipment costs and any materials used not to exceed $1,500. In the event that such costs are expected to exceed $1,500, the Company shall provide the Customer with a binding estimate detailing the scope of work and associated costs to perform such work prior to the date on which the work is schedule to commence.*

Although the Company did not agree that the concern raised by the Industrial Group to warranted rejection of the Company's proposed provision, the parties resolved the dispute over the proposed change through the revised language.[39]

Q54. Please discuss Section I.B.6. of the Settlement Agreement (GS/IP).

I&M agrees to retain language it had proposed to strike from Tariff G.S., Tariff L.G.S., Tariff I.P. and Waste and Sewage Service – Tariff W.S.S. stating that each tariff remains available to customers having other sources of energy supply who purchase standby or backup electric service from the Company, the applicable maximum and minimum demands for which such customers must contract, the Company's service obligation, and references to the applicable minimum charge. As proposed in its case in chief, I&M agrees to strike from each of these tariffs the sentence which reads:

> *"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."*

A copy of the revised tariff language is included in the Special Terms and Conditions provision of each of the identified tariffs in Attachment AJW-10-S. This change clarifies the intent of the Company's proposed language change to

[39] See Rebuttal testimony of Company witness Cooper, at 3.

cease applying the above language to customers with generation but not to preclude such customer from receiving service under those Tariffs.

Q55. Please discuss Section I.B.7. of the Settlement Agreement (CPP).

Company witness Walter explained in his rebuttal testimony why I&M disagreed with the OUCC's proposal related to I&M's proposed Critical Peak Pricing ("CPP") program that I&M add major holidays to the exemptions.[40] After discussing this issue further with the OUCC, as part of the Settlement Agreement, I&M agreed to propose in its next base rate case provisions addressing the exclusion of holidays from the days for which Critical Peak Events may be called. This provision allows the Company to work through the technical issues associated with this approach.

In addition, in the section the Settling Parties further agreed that I&M is not receiving authorization for Tariff R.S. – Critical Peak Pricing as an "opt-out" rate in this proceeding, and that I&M must obtain Commission approval for any opt-out rate provisions prior to implementation. This provision reasonably clarifies the Company's proposal in response to the concern raised by OUCC witness Boerger.[41]

Q56. Can you further discuss the rate design associated with the proposed PRA factors under the Settlement Agreement?

There are four components to the PRA which are summarized in the table below.

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[40] Rebuttal testimony of Company witness Walter, p. 21.

[41] See Rebuttal testimony of Company witness Walter, at 20; OUCC witness Boerger testimony at 14.

Phase-in Rate Adjustment (PRA) Summary

	Component	Effective Date	Termination Date	Reference
1	Net Plant Credit	Phase I	Phase II*	I&M Seger-Lawson Direct
2	Rockport Unit 2 Charge	Phase I	December 7, 2022**	Section I.A.2.b
3	Excluded Capacity Credit	Phase I	December 7, 2022	Section I.A.4
4	Rockport Unit 2 NBV Credit	Phase II	Next Base Case	Section I.A.3

* As discussed by I&M witness Seger-Lawson, I&M's final PRA compliance filing will adjust the Net Plant Credit to reflect the lower of actual Test Year End net plant or the Test Year End net plant approved by the Commission

** Or earlier as described in Section I.A.2.b

The Net Plant Credit was designed in a manner consistent with the Company's proposal in this filing and the methodology utilized for the calculation in prior I&M rate cases. The rates for the other 3 components of the PRA were designed consistent with the methodology used for virtually all I&M riders, where costs were identified as either demand- or energy-related and allocated to each class on demand or energy, respectively. For each class, demand costs were generally collected through demand charges where possible (Tariffs I.P., L.G.S, G.S. and Electric Heating General "E.H.G."), and otherwise through energy charges. In all cases, energy costs were collected through energy charges.

Section I.C.

Q57. Please discuss Section I.C. of the Settlement Agreement (remaining issues).

Section I.C. of the Settlement Agreement clarifies that any matters not addressed by this Settlement Agreement will be adopted as proposed by I&M. This Section also recognizes that time is of the essence. The Settling Parties seek a Commission order approving the Settlement Agreement within a timeframe consistent with IC 8-1-2-42.7(f). The Settling Parties contemplate that the new Phase I rates will be effective on the date of the Order.

Typical Bill Comparison

Q58. Has I&M updated the typical bill comparison (previously provided as Attachment JLF-4) to reflect the Settlement Agreement?

Yes, this information is provided in Attachment AJW-4-S, which presents a comparison of typical bills under present rate structures and the Settlement Agreement rate structures at Phase I rates for each of the major tariff classes at a range of usage levels.

For a typical residential customer using 1,000 kWh, the Phase I rates reflect a total monthly bill decrease of $1.48 or 0.9%. For Phase II, the Settlement Agreement reflects an additional monthly bill decrease of $7.95 or 5.1% at the end of the Test Year.

Tariff

Q59. Has the Company updated its proposed tariff to reflect the Settlement Agreement?

Yes. Attachment AJW-9-S, which updates Attachment KCC-1 (included with Company witness Cooper's direct testimony), is a complete copy of the introductory sections of the proposed Tariff Book, including the Table of Contents and Terms and Conditions of Service sections, with changes updated to reflect the Settlement Agreement shown in redline.

Attachment AJW-10-S, which updates Attachment KCC-2 (included with Company witness Cooper's direct testimony), is a complete copy of I&M's Tariffs and Riders sections of the proposed Tariff Book 19 with changes from the Settlement Agreement shown in redline.

These attachments provide both the text and the rates and are provided to facilitate the Commission's review of the Settlement Agreement.

Q60. What does the Company anticipate filing as a compliance filing if the Settlement Agreement is approved?

The Company is asking the Commission to approve I&M's revised base rates and rider rates effective the date of the Commission's Final Order, consistent with Cause No. 45235. I&M has submitted to the Commission an updated tariff book (see Attachment AJW-9-S and Attachment AJW-10-S) that revises all terms and conditions of service, tariffs and base rates[42] for the Settlement Agreement. The Company anticipates that its compliance filing will focus on the riders to make the final updates that are necessary to incorporate impacts of the Settlement Agreement on I&M's current riders at that time.

Consistent with the process I&M used in Cause No. 45235, upon receipt of the Commission's Final Order I&M will work expeditiously to revise its riders to reflect all impacts associated with the Settlement Agreement and submit these to the Commission for approval, along with a clean version of its approved tariff book. The Company will endeavor to submit a clear and comprehensive audit package to the Commission to facilitate the review of all updates. Once the Commission approves I&M's final rates I&M will bill customers on a service rendered basis using an effective date the same as the date of the Commission's Final Order for the final base rates and rider rates approved in this Cause.

Sections II and III

Q61. What other provisions does the Settlement Agreement contain?

The Settlement Agreement sets forth the Settling Parties' agreement that the Settlement Agreement is reflective of a negotiated settlement and neither the making of the Settlement Agreement nor any of its provisions shall constitute an admission by any Settling Party in this or any other litigation or proceeding. The

[42] Rider rates are subject to change based on I&M's final compliance filing following the Commission's Final Order in this Cause.

Settlement Agreement is a package compromise and will be null and void unless approved in its entirety without an unacceptable modification or further condition. The Settlement Agreement sets forth the Settling Parties' agreement that it shall not be used as precedent by any person or entity in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce this Settlement Agreement. The Settlement Agreement also includes provisions considering the substantial evidence in the record supporting the approval of the Settlement Agreement, recognizes the confidentiality of settlement communications, and reflects other terms typically found in settlement agreements before this Commission.

IV Muncie Settlement Agreement

Q62. Please discuss the Muncie Settlement Agreement.

Intervenor City of Muncie filed testimony seeking support and cooperation from I&M regarding the City's effort to develop a City-owned solar generating facility to be located on the former General Motors brownfield site in southwest Muncie referred to in testimony as the "Chevy Plant".[43] In his rebuttal testimony, Company witness Lucas apologized for the confusion, clarified certain FERC requirements and committed to continue to work with the City on this project and to provide clear information on process and regulatory framework to move this project forward.[44]

The Muncie Settlement Agreement memorializes this commitment and does so in substantial detail to assuage Muncie's concerns and to clarify the Company's role.

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[43] Muncie witness Ridenour, at 7, 11.

[44] Company witness Lucas rebuttal, at 16-17.

V Public Interest

Q63. In your opinion, is Commission approval of both the Settlement Agreement and the separate Muncie Settlement Agreement in the overall public interest?

Yes. Settlement is a reasonable means of resolving a controversial proceeding in a manner that is fair and balanced to all concerned. While this is true with respect to a general rate case, the complexity of a rate case proceeding can make settlement challenging to achieve. In this case, the Presiding Officers set forth expectations in the procedural order that prompted the parties to commence settlement discussions in earnest so that the settlement agreement and supporting testimony could be provided to the Commission in a manner that allowed the Commission sufficient opportunity to review the settlement and supporting testimony as well as allowing the Commission to manage its hearing room schedule efficiently. The Presiding Officers also made themselves available on relatively short notice for an attorneys call so that the parties could keep them informed of the status of the discussions and receive guidance as to settlement procedural matters. The support of the Commission as the parties worked to reach a global settlement was helpful and is appreciated.

It is my opinion the Settlement Agreement is in the public interest. The Settlement Agreement is supported by and within the scope of the evidence presented by the Settling Parties. The Settlement Agreement represents the result of extensive, good faith, arm's-length negotiations of the conceptual framework and details of the Settlement Agreement. Experts were involved with legal counsel and substantial time was devoted to the settlement discussions.

Taken as a whole, the Settlement Agreement reasonably addresses the concerns raised in this proceeding and provides a balanced, cooperative outcome of the issues in this Cause.

The separate Muncie Settlement Agreement reasonably addresses the concern raised by Muncie and is also the product of arm's-length negotiations.

I&M asks the Commission to issue an order approving both settlement agreements in their entirety.

Q64. Does this conclude your pre-filed verified testimony in support of settlement agreements?

Yes.

VERIFICATION

I, Andrew J. Williamson, Director of Regulatory Services at Indiana Michigan Power Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

Date: November 19, 2021

Andrew J. Williamson

Andrew J. Williamson

Line No.	(a) Description	(b) Total Company Capitalization	(c) Percent of Total	(d) % Cost Rate	(e) % Weighted Average Cost Rate
1		$			
2	Long-Term Debt	2,822,302,210	41.42%	4.44%	1.84%
3	Common Equity	2,762,126,699	40.54%	9.70%	3.93%
4	Customer Deposits	41,698,455	0.61%	2.00%	0.01%
5	ADFIT[1]	1,170,202,985	17.17%	0.00%	0.00%
6	ADITC[2]	17,469,705	0.26%	7.04%	0.02%
7					
8	Total	6,813,800,053	100.00%		5.80%
9					
10					
11					
12	Cost of Investor Supplied Capital				
13	Long-Term Debt	2,822,302,210	50.54%	4.44%	2.24%
14	Common Equity	2,762,126,699	49.46%	9.70%	4.80%
15	Total	5,584,428,909	100.00%		7.04%

[1]Accumulated Deferred Federal Income Taxes

[2]Accumulated Deferred Job Development Investment Tax Credits

Line No.	(a) Description	(b) Total Company Capitalization	(c) Percent of Total	(d) % Cost Rate	(e) % Weighted Average Cost Rate
1		$			
2	Long-Term Debt	2,873,862,352	40.70%	4.44%	1.81%
3	Common Equity	2,873,862,352	40.70%	9.70%	3.95%
4	Customer Deposits	41,698,455	0.59%	2.00%	0.01%
5	ADFIT[1]	1,257,846,893	17.81%	0.00%	0.00%
6	ADITC[2]	13,678,705	0.19%	7.07%	0.01%
7					
8	Total	7,060,948,756	100.00%		5.78%
9					
10					
11					
12	Cost of Investor Supplied Capital				
13	Long-Term Debt	2,873,862,352	50.00%	4.44%	2.22%
14	Common Equity	2,873,862,352	50.00%	9.70%	4.85%
15	Total	5,747,724,703	100.00%		7.07%

[1]Accumulated Deferred Federal Income Taxes

[2]Accumulated Deferred Job Development Investment Tax Credits

INDIANA MICHIGAN POWER COMPANY
SCHEDULE I - CALCULATION OF DEPRECIATION RATES BY THE REMAINING LIFE METHOD
BASED ON DEPRECIABLE PLANT IN SERVICE AT DECEMBER 31, 2020 (1)
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

IN

ACCOUNT NO.	ACCOUNT TITLE	ORIGINAL COST	NET SALVG RATIO	TOTAL TO BE RECOVERED	CALCULATED DEPRECIATION REQUIREMENT	ALLOCATED ACCUMULATED DEPRECIATION	REMAINING TO BE RECOVERED	AVG REMAIN LIFE	RECOMMENDED ANNUAL ACCRUAL AMOUNT	RECOMMENDED ANNUAL ACCRUAL %
(I)	(II)	(III)	(IV)	(V)	(VI)	(VII)	(VIII)	(IX)	(X)	(XI)
STEAM PRODUCTION PLANT										
Rockport										
311.0	Structures & Improvements	103,081,792	1.02	105,143,428	90,063,864	53,340,105	51,803,323	5.47	9,470,443	9.19%
312.0	Boiler Plant Equipment	646,499,630	1.02	659,429,623	531,021,903	314,496,432	344,933,191	5.39	63,995,026	9.90%
314.0	Turbogenerator Units	110,198,824	1.02	112,402,800	92,010,973	54,493,275	57,909,525	5.35	10,824,210	9.82%
315.0	Accessory Electrical Equipment	60,038,956	1.02	61,239,735	53,196,660	31,505,593	29,734,142	5.44	5,465,835	9.10%
316.0	Miscellaneous Power Plant Equip.	17,952,020	1.02	18,311,060	15,204,150	9,004,621	9,306,439	5.36	1,736,276	9.67%
	Total Rockport	937,771,222	1.02	956,526,646	781,497,550	462,840,025	493,686,620	5.40	91,491,790	9.76%
Total Steam Production Plant		**937,771,222**	**1.02**	**956,526,646**	**781,497,550**	**462,840,025**	**493,686,620**	**5.40**	**91,491,790**	**9.76%**
NUCLEAR PRODUCTION PLANT										
Cook Unit 1										
321.0	Structures & Improvements	86,734,372	1.01	87,601,716	67,751,167	52,347,711	35,254,005	11.28	3,125,355	3.60%
322.0	Reactor Plant Equipment	782,729,686	1.03	806,211,577	503,156,645	388,762,289	417,449,288	10.95	38,123,223	4.87%
323.0	Turbogenerator Units	312,897,355	1.03	322,284,276	187,150,479	144,601,188	177,683,088	10.45	17,003,166	5.43%
324.0	Accessory Electrical Equipment	137,248,173	1.00	137,248,173	91,626,880	70,795,200	66,452,973	11.13	5,970,618	4.35%
325.0	Miscellaneous Power Plant Equip.	36,218,603	1.00	36,218,603	22,654,736	17,504,106	18,714,497	10.97	1,705,971	4.71%
	Total Cook Unit 1	1,355,828,189	1.02	1,389,564,344	872,339,907	674,010,494	715,553,850	10.85	65,928,332	4.86%
Cook Unit 2										
321.0	Structures & Improvements	378,680,285	1.02	386,253,891	249,249,636	192,581,892	193,671,999	14.15	13,687,067	3.61%
322.0	Reactor Plant Equipment	1,053,868,998	1.03	1,085,485,068	600,707,437	464,134,580	621,350,488	13.62	45,620,447	4.33%
323.0	Turbogenerator Units	425,843,325	1.04	442,877,058	215,681,127	166,645,297	276,231,761	12.83	21,530,145	5.06%
324.0	Accessory Electrical Equipment	200,678,427	1.00	200,678,427	106,821,127	82,534,984	118,143,443	13.91	8,493,418	4.23%
325.0	Miscellaneous Power Plant Equip.	248,016,731	1.00	248,016,731	137,376,467	106,143,465	141,873,266	13.66	10,386,037	4.19%
	Total Cook Unit 2	2,307,087,766	1.02	2,363,311,175	1,309,835,794	1,012,040,218	1,351,270,957	13.55	99,717,114	4.32%
Total Nuclear Production Plant		**3,662,915,955**	**1.02**	**3,752,875,519**	**2,182,175,701**	**1,686,050,712**	**2,066,824,807**	**12.48**	**165,645,446**	**4.52%**
HYDRAULIC PRODUCTION PLANT										
Berrien Springs										
331.0	Structures & Improvements	696,548	1.04	724,410	423,273	341,708	382,702	13.34	28,688	4.12%
332.0	Reservoirs, Dams & Waterways	6,320,266	1.04	6,573,077	4,453,917	3,595,649	2,977,428	13.40	222,196	3.52%
333.0	Waterwheels, Turbines & Generators	8,386,954	1.04	8,722,432	5,477,687	4,422,138	4,300,294	13.21	325,533	3.88%
334.0	Accessory Electrical Equip.	1,417,718	1.04	1,474,427	966,929	780,602	693,825	13.04	53,207	3.75%
335.0	Misc. Power Plant Equip.	929,404	1.04	966,580	575,405	464,525	502,055	13.29	37,777	4.06%
	Total Berrien Springs	17,750,890	1.04	18,460,926	11,897,211	9,604,622	8,856,304	13.27	667,402	3.76%
Buchanan										
331.0	Structures & Improvements	660,195	1.05	693,205	406,287	327,996	365,209	13.34	27,377	4.15%
332.0	Reservoirs, Dams & Waterways	5,154,683	1.05	5,412,417	3,825,496	3,088,324	2,324,093	13.40	173,440	3.36%
333.0	Waterwheels, Turbines & Generators	1,414,445	1.05	1,485,167	1,076,004	868,658	616,509	13.21	46,670	3.30%
334.0	Accessory Electrical Equip.	1,108,771	1.05	1,164,210	808,427	652,643	511,567	13.04	39,231	3.54%
335.0	Misc. Power Plant Equip.	311,833	1.05	327,425	192,788	155,638	171,787	13.29	12,926	4.15%
	Total Buchanan	8,649,927	1.05	9,082,423	6,309,002	5,093,259	3,989,164	13.31	299,643	3.46%

INDIANA MICHIGAN POWER COMPANY
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IN

ACCOUNT NO.	ACCOUNT TITLE	ORIGINAL COST	NET SALVG RATIO	TOTAL TO BE RECOVERED	CALCULATED DEPRECIATION REQUIREMENT	ALLOCATED ACCUMULATED DEPRECIATION	REMAINING TO BE RECOVERED	AVG REMAIN LIFE	RECOMMENDED ANNUAL ACCRUAL AMOUNT	RECOMMENDED ANNUAL ACCRUAL %
(I)	(II)	(III)	(IV)	(V)	(VI)	(VII)	(VIII)	(IX)	(X)	(XI)
Elkhart										
331.0	Structures & Improvements	1,632,902	1.03	1,681,889	1,183,377	955,341	726,548	7.42	97,918	6.00%
332.0	Reservoirs, Dams & Waterways	11,027,557	1.03	11,358,384	7,468,137	6,029,029	5,329,355	7.45	715,350	6.49%
333.0	Waterwheels, Turbines & Generators	875,459	1.03	901,723	699,106	564,389	337,334	7.35	45,896	5.24%
334.0	Accessory Electrical Equip.	766,670	1.03	789,670	607,967	490,812	298,858	7.27	41,108	5.36%
335.0	Misc. Power Plant Equip.	342,337	1.03	352,607	207,932	167,864	184,743	7.39	24,999	7.30%
	Total Elkhart	14,644,925	1.03	15,084,273	10,166,519	8,207,435	6,876,838	7.43	925,270	6.32%
Twin Branch										
331.0	Structures & Improvements	1,428,784	1.05	1,500,223	757,013	611,137	889,086	13.34	66,648	4.66%
332.0	Reservoirs, Dams & Waterways	8,416,861	1.05	8,837,704	5,373,324	4,337,886	4,499,818	13.40	335,807	3.99%
333.0	Waterwheels, Turbines & Generators	9,909,128	1.05	10,404,584	5,960,786	4,812,145	5,592,439	13.21	423,349	4.27%
334.0	Accessory Electrical Equip.	2,876,083	1.05	3,019,887	1,784,149	1,440,344	1,579,543	13.04	121,131	4.21%
335.0	Misc. Power Plant Equip.	1,005,606	1.05	1,055,886	474,832	383,332	672,554	13.29	50,606	5.03%
	Total Twin Branch	23,636,462	1.05	24,818,285	14,350,104	11,584,844	13,233,441	13.27	997,541	4.22%
Constantine										
331.0	Structures & Improvements	470,900	1.17	550,953	243,136	196,284	354,669	29.66	11,958	2.54%
332.0	Reservoirs, Dams & Waterways	1,653,789	1.17	1,934,933	898,583	725,426	1,209,507	29.99	40,330	2.44%
333.0	Waterwheels, Turbines & Generators	993,032	1.17	1,161,847	582,783	470,481	691,366	29.01	23,832	2.40%
334.0	Accessory Electrical Equip.	671,796	1.17	786,001	257,651	208,002	577,999	28.18	20,511	3.05%
335.0	Misc. Power Plant Equip.	475,641	1.17	556,500	155,263	125,344	431,156	29.43	14,650	3.08%
	Total Constantine	4,265,158	1.17	4,990,235	2,137,416	1,725,537	3,264,698	29.34	111,281	2.61%
Mottville										
331.0	Structures & Improvements	797,060	1.04	828,942	550,003	444,018	384,924	10.40	37,012	4.64%
332.0	Reservoirs, Dams & Waterways	2,312,828	1.04	2,405,341	1,759,748	1,420,645	984,696	10.44	94,320	4.08%
333.0	Waterwheels, Turbines & Generators	639,576	1.04	665,159	507,583	409,772	255,387	10.32	24,747	3.87%
334.0	Accessory Electrical Equip.	772,571	1.04	803,474	549,415	443,543	359,931	10.22	35,218	4.56%
335.0	Misc. Power Plant Equip.	409,136	1.04	425,501	240,706	194,322	231,179	10.37	22,293	5.45%
336.0	Roads, Railroads & Bridges	902	1.04	938	796	643	295	10.38	28	3.15%
	Total Mottville	4,932,073	1.04	5,129,356	3,608,251	2,912,943	2,216,413	10.38	213,618	4.33%
Crew Service Center										
331.0	Structures & Improvements	417,303	1.05	438,168	291,864	235,622	202,546	29.66	6,829	1.64%
335.0	Misc. Power Plant Equip.	126,865	1.05	133,208	89,929	72,600	60,608	29.43	2,059	1.62%
	Total Crew Service Center	544,168	1.05	571,376	381,793	308,222	263,154	29.61	8,888	1.63%
Total Hydraulic Production Plant		**74,423,603**	**1.05**	**78,136,874**	**48,850,296**	**39,436,861**	**38,700,012**	**12.01**	**3,223,644**	**4.33%**

INDIANA MICHIGAN POWER COMPANY
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IN

ACCOUNT NO. (I)	ACCOUNT TITLE (II)	ORIGINAL COST (III)	NET SALVG RATIO (IV)	TOTAL TO BE RECOVERED (V)	CALCULATED DEPRECIATION REQUIREMENT (VI)	ALLOCATED ACCUMULATED DEPRECIATION (VII)	REMAINING TO BE RECOVERED (VIII)	AVG REMAIN LIFE (IX)	RECOMMENDED ANNUAL ACCRUAL AMOUNT (X)	RECOMMENDED ANNUAL ACCRUAL % (XI)
OTHER PRODUCTION PLANT										
Deer Creek Solar Facility										
344.0	Generators	5,668,204	1.03	5,838,250	2,189,344	2,027,991	3,810,259	12.50	304,821	5.38%
345.0	Accessory Electric Equip.	720,502	1.03	742,117	162,301	150,340	591,777	12.50	47,342	6.57%
346.0	Misc. Power Plant Equip.	10,893	1.03	11,220	1,659	1,537	9,683	12.50	775	7.11%
	Total Deer Creek Solar Facility	6,399,599		6,591,587	2,353,304	2,179,868	4,411,719	12.50	352,938	5.51%
Olive Solar Facility										
341.0	Structures & Improvements	376,687	1.03	387,988	126,096	116,803	271,185	13.50	20,088	5.33%
344.0	Generators	11,184,837	1.03	11,520,382	3,744,124	3,468,187	8,052,195	13.50	596,459	5.33%
345.0	Accessory Electric Equip.	269,062	1.03	277,134	90,069	83,431	193,703	13.50	14,348	5.33%
346.0	Misc. Power Plant Equip.	215,250	1.03	221,708	72,055	66,745	154,963	13.50	11,479	5.33%
	Total Olive Solar Facility	12,045,836	1.03	12,407,211	4,032,344	3,735,166	8,672,045	13.50	642,374	5.33%
Twin Branch Solar Facility										
344.0	Generators	6,955,324	1.04	7,233,537	2,350,900	2,177,641	5,055,896	13.50	374,511	5.38%
Watervliet Facility										
341.0	Structures & Improvements	358,237	1.03	368,984	119,920	111,082	257,902	13.50	19,104	5.33%
344.0	Generators	11,107,366	1.03	11,440,587	3,718,191	3,444,164	7,996,423	13.50	592,328	5.33%
346.0	Misc. Power Plant Equip.	343,931	1.03	354,249	114,883	106,416	247,833	13.50	18,358	5.34%
	Total Watervliet Facility	11,809,534	1.03	12,163,820	3,952,994	3,661,662	8,502,158	13.50	629,789	5.33%
Total Other Production Plant		**37,210,293**	1.03	**38,396,155**	**12,689,542**	**11,754,335**	**26,641,818**	13.32	**1,999,612**	**5.37%**
Total Production Plant		**4,712,321,073**	**1.02**	**4,825,935,194**	**3,025,213,089**	**2,200,081,933**	**2,625,853,257**	**10.01**	**262,360,492**	**5.57%**
TRANSMISSION PLANT										
350.1	Land Rights	62,292,873	1.00	62,292,873	23,350,156	17,804,684	44,488,189	40.64	1,094,690	1.76%
352.0	Structures & Improvements	52,265,232	1.10	57,491,755	7,849,551	5,985,346	51,506,409	56.13	917,627	1.76%
353.0	Station Equipment	826,489,176	1.10	909,138,094	213,734,540	162,974,326	746,163,768	33.66	22,167,670	2.68%
354.0	Towers & Fixtures	230,452,983	1.39	320,329,646	191,173,868	145,771,629	174,558,017	26.61	6,559,865	2.85%
355.0	Poles & Fixtures	208,136,265	1.64	341,343,475	44,409,633	33,862,706	307,480,769	43.49	7,070,149	3.40%
356.0	OH Conductor & Devices	294,558,395	1.35	397,653,833	159,649,845	121,734,305	275,919,528	40.10	6,880,786	2.34%
357.0	Underground Conduit	2,241,687	1.00	2,241,687	1,117,374	852,007	1,389,680	27.59	50,369	2.25%
358.0	Underground Conductor	4,522,363	1.13	5,110,270	1,464,317	1,116,554	3,993,716	42.81	93,289	2.06%
359.0	Roads and Trails	91,159	1.00	91,159	25,925	19,768	71,391	46.51	1,535	1.68%
Total Transmission Plant		**1,681,050,133**	**1.25**	**2,095,692,792**	**642,775,209**	**490,121,325**	**1,605,571,467**	**35.81**	**44,835,980**	**2.67%**

INDIANA MICHIGAN POWER COMPANY
SCHEDULE I - CALCULATION OF DEPRECIATION RATES BY THE REMAINING LIFE METHOD
BASED ON DEPRECIABLE PLANT IN SERVICE AT DECEMBER 31, 2020 (1)
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

IN

ACCOUNT NO. (I)	ACCOUNT TITLE (II)	ORIGINAL COST (III)	NET SALVG RATIO (IV)	TOTAL TO BE RECOVERED (V)	CALCULATED DEPRECIATION REQUIREMENT (VI)	ALLOCATED ACCUMULATED DEPRECIATION (VII)	REMAINING TO BE RECOVERED (VIII)	AVG REMAIN LIFE (IX)	RECOMMENDED ANNUAL ACCRUAL AMOUNT (X)	RECOMMENDED ANNUAL ACCRUAL % (XI)
DISTRIBUTION PLANT - IN										
360.1	Land Rights	10,926,039	1.00	10,926,039	2,388,029	2,947,585	7,978,454	50.61	157,646	1.44%
361.0	Structures & Improvements	32,691,043	1.25	40,863,804	3,686,322	3,066,234	37,797,570	58.94	641,289	1.96%
362.0	Station Equipment	379,401,090	1.12	424,929,221	51,766,238	34,619,804	390,309,417	40.16	9,718,860	2.56%
363.0	Storage Battery Equipment	5,606,730	1.00	5,606,730	4,242,655	3,747,078	1,859,652	3.65	509,494	9.09%
364.0	Poles, Towers, & Fixtures	252,111,755	1.87	471,448,982	83,961,086	112,061,327	359,387,655	40.02	8,980,201	3.56%
365.0	Overhead Conductor & Devices	399,931,378	1.16	463,920,398	74,997,865	90,991,491	372,928,907	41.31	9,027,570	2.26%
366.0	Underground Conduit	144,882,340	1.00	144,882,340	21,257,149	22,768,052	122,114,288	61.71	1,978,841	1.37%
367.0	Underground Conductor	255,708,978	1.00	255,708,978	48,263,147	43,352,417	212,356,561	50.28	4,223,480	1.65%
368.0	Line Transformers	318,204,324	1.08	343,660,670	98,466,817	134,226,451	209,434,219	27.06	7,739,624	2.43%
369.0	Services	166,556,147	1.24	206,529,622	49,502,488	60,380,012	146,149,610	39.02	3,745,505	2.25%
370.0	Meters (3)	76,493,447	1.20	91,792,136	40,860,844	40,860,844	50,931,292	(3)	7,710,539	10.08%
371.0	Installations on Custs. Prem.	20,434,795	1.23	25,134,798	7,560,590	13,489,503	11,645,295	11.64	1,000,455	4.90%
373.0	Street Lighting & Signal Sys.	18,113,668	1.18	21,374,128	9,749,457	12,452,701	8,921,427	13.12	679,987	3.75%
Total Distribution Plant - IN		**2,081,061,734**	**1.20**	**2,506,777,846**	**496,702,687**	**574,963,499**	**1,931,814,347**	**34.43**	**56,113,490**	**2.70%**
DISTRIBUTION PLANT - MI										
360.1	Land Rights	6,056,743	1.00	6,056,743	1,371,435	1,692,786	4,363,957	50.61	87,389	1.44%
361.0	Structures & Improvements	4,510,462	1.25	5,638,078	650,345	540,949	5,097,129	58.94	88,480	1.96%
362.0	Station Equipment	96,403,578	1.12	107,972,007	15,863,769	10,609,243	97,362,764	40.16	2,469,505	2.56%
363.0	Storage Battery Equipment	0	1.00	0	0	0	0	0.00	0	9.09%
364.0	Poles, Towers, & Fixtures	80,503,822	1.87	150,542,147	32,451,643	43,312,615	107,229,532	40.02	2,867,540	3.56%
365.0	Overhead Conductor & Devices	139,323,640	1.16	161,615,422	24,893,815	30,202,531	131,412,891	41.31	3,144,924	2.26%
366.0	Underground Conduit	12,573,950	1.00	12,573,950	2,780,271	2,977,885	9,596,065	61.71	171,738	1.37%
367.0	Underground Conductor	37,852,912	1.00	37,852,912	14,814,525	13,307,161	24,545,751	50.28	625,207	1.65%
368.0	Line Transformers	52,380,639	1.08	56,571,090	16,556,427	22,569,130	34,001,960	27.06	1,274,044	2.43%
369.0	Services	33,052,679	1.24	40,985,322	11,709,296	14,282,261	26,703,061	39.02	743,287	2.25%
370.0	Meters	22,239,359	1.20	26,687,231	5,776,094	5,776,094	20,911,137	(3)	2,241,727	10.08%
371.0	Installations on Custs. Prem.	8,344,653	1.23	10,263,923	3,593,958	6,412,292	3,851,631	11.64	408,541	4.90%
373.0	Street Lighting & Signal Sys.	5,882,009	1.18	6,940,771	1,682,554	2,149,078	4,791,693	13.12	220,811	3.75%
Total Distribution Plant - MI		**499,124,446**	**1.25**	**623,699,596**	**132,144,132**	**153,832,025**	**469,867,571**	**32.76**	**14,343,194**	**2.87%**
Total Distribution Plant		**2,580,186,180**	**1.21**	**3,130,477,442**	**628,846,819**	**728,795,524**	**2,401,681,918**	**34.09**	**70,456,684**	**2.73%**
GENERAL PLANT										
390.0	Structures & Improvements	61,646,560	1.05	64,728,888	13,985,046	9,451,468	55,277,420	35.28	1,566,820	2.54%
391.0	Office Furniture & Equipment	5,869,860	0.97	5,693,764	2,427,416	1,640,513	4,053,251	12.62	321,177	5.47%
393.0	Stores Equipment	996,539	1.00	996,539	285,967	193,264	803,275	9.98	80,488	8.08%
394.0	Tools Shop & Garage Equipment	16,780,302	1.00	16,780,302	7,424,999	5,018,013	11,762,289	8.92	1,318,642	7.86%
395.0	Laboratory Equipment	240,988	0.99	238,578	114,920	77,666	160,912	10.37	15,517	6.44%
396.0	Power Operated Equipment	543,715	1.00	543,715	355,674	240,374	303,341	8.65	35,068	6.45%
397.0	Communication Equipment	66,159,303	1.01	66,820,896	18,584,595	12,559,966	54,260,930	19.49	2,784,040	4.21%
398.0	Miscellaneous Equipment	10,826,054	0.92	9,959,970	4,036,340	2,727,867	7,232,103	17.84	405,387	3.74%
Total General Plant		**163,063,321**	**1.02**	**165,762,652**	**47,214,957**	**31,909,131**	**133,853,521**	**20.51**	**6,527,140**	**4.00%**
	Total Depreciable Plant	**9,136,620,707**	**1.12**	**10,217,868,080**	**4,344,050,074**	**3,450,907,913**	**6,766,960,163**	**17.61**	**384,180,296**	**4.20%**

Notes:

(1) Production Plant original cost includes 2021-22 forecasted plant additions totaling $269,468,143. A corresponding adjustment was made to Production Plant accumulated depreciation that includes an additional two years of depreciation using the expected plant balances at 12/31/2022.

(2) Rockport depreciation rates are calculated using a 2028 retirement date.

(3) The depreciation rate for Distribution Account 370, Meters, was calculated to include AMI Meter deployment set to begin in 2021 along with the expected retirement of the current meters. The depreciation rate that was calculated is based on a 15 year service life of the AMI Meters to be installed.

**INDIANA MICHIGAN POWER COMPANY
COMPARE COMPANY PROPOSED DEPRECIATION RATES
TO DEPRECIATION RATES IN SETTLEMENT**

IN

	ACCOUNT	COMPANY PROPOSED RATE	SETTLEMENT RATE	DIFFERENCE
STEAM PRODUCTION PLANT				
Rockport				
311.0	Structures & Improvements	9.19%	9.19%	0.00%
312.0	Boiler Plant Equipment	9.90%	9.90%	0.00%
314.0	Turbogenerator Units	9.82%	9.82%	0.00%
315.0	Accessory Electrical Equipment	9.10%	9.10%	0.00%
316.0	Miscellaneous Power Plant Equip.	9.67%	9.67%	0.00%
	Total Rockport	9.76%	9.76%	0.00%
Total Steam Production Plant		**9.76%**	**9.76%**	**0.00%**
NUCLEAR PRODUCTION PLANT				
Cook Unit 1				
321.0	Structures & Improvements	3.60%	3.60%	0.00%
322.0	Reactor Plant Equipment	4.87%	4.87%	0.00%
323.0	Turbogenerator Units	5.43%	5.43%	0.00%
324.0	Accessory Electrical Equipment	4.35%	4.35%	0.00%
325.0	Miscellaneous Power Plant Equip.	4.71%	4.71%	0.00%
	Total Cook Unit 1	4.86%	4.86%	0.00%
Cook Unit 2				
321.0	Structures & Improvements	3.61%	3.61%	0.00%
322.0	Reactor Plant Equipment	4.33%	4.33%	0.00%
323.0	Turbogenerator Units	5.06%	5.06%	0.00%
324.0	Accessory Electrical Equipment	4.23%	4.23%	0.00%
325.0	Miscellaneous Power Plant Equip.	4.19%	4.19%	0.00%
	Total Cook Unit 2	4.32%	4.32%	0.00%
Total Nuclear Production Plant		**4.52%**	**4.52%**	**0.00%**
HYDRAULIC PRODUCTION PLANT				
Berrien Springs				
331.0	Structures & Improvements	4.12%	4.12%	0.00%
332.0	Reservoirs, Dams & Waterways	3.52%	3.52%	0.00%
333.0	Waterwheels, Turbines & Generators	3.88%	3.88%	0.00%
334.0	Accessory Electrical Equip.	3.75%	3.75%	0.00%
335.0	Misc. Power Plant Equip.	4.06%	4.06%	0.00%
	Total Berrien Springs	3.76%	3.76%	0.00%
Buchanan				
331.0	Structures & Improvements	4.15%	4.15%	0.00%
332.0	Reservoirs, Dams & Waterways	3.36%	3.36%	0.00%
333.0	Waterwheels, Turbines & Generators	3.30%	3.30%	0.00%
334.0	Accessory Electrical Equip.	3.54%	3.54%	0.00%
335.0	Misc. Power Plant Equip.	4.15%	4.15%	0.00%
	Total Buchanan	3.46%	3.46%	0.00%

INDIANA MICHIGAN POWER COMPANY
COMPARE COMPANY PROPOSED DEPRECIATION RATES
TO DEPRECIATION RATES IN SETTLEMENT

IN

ACCOUNT		COMPANY PROPOSED RATE	SETTLEMENT RATE	DIFFERENCE
Elkhart				
331.0	Structures & Improvements	6.00%	6.00%	0.00%
332.0	Reservoirs, Dams & Waterways	6.49%	6.49%	0.00%
333.0	Waterwheels, Turbines & Generators	5.24%	5.24%	0.00%
334.0	Accessory Electrical Equip.	5.36%	5.36%	0.00%
335.0	Misc. Power Plant Equip.	7.30%	7.30%	0.00%
	Total Elkhart	6.32%	6.32%	0.00%
Twin Branch				
331.0	Structures & Improvements	4.66%	4.66%	0.00%
332.0	Reservoirs, Dams & Waterways	3.99%	3.99%	0.00%
333.0	Waterwheels, Turbines & Generators	4.27%	4.27%	0.00%
334.0	Accessory Electrical Equip.	4.21%	4.21%	0.00%
335.0	Misc. Power Plant Equip.	5.03%	5.03%	0.00%
	Total Twin Branch	4.22%	4.22%	0.00%
Constantine				
331.0	Structures & Improvements	2.54%	2.54%	0.00%
332.0	Reservoirs, Dams & Waterways	2.44%	2.44%	0.00%
333.0	Waterwheels, Turbines & Generators	2.40%	2.40%	0.00%
334.0	Accessory Electrical Equip.	3.05%	3.05%	0.00%
335.0	Misc. Power Plant Equip.	3.08%	3.08%	0.00%
	Total Constantine	2.61%	2.61%	0.00%
Mottville				
331.0	Structures & Improvements	4.64%	4.64%	0.00%
332.0	Reservoirs, Dams & Waterways	4.08%	4.08%	0.00%
333.0	Waterwheels, Turbines & Generators	3.87%	3.87%	0.00%
334.0	Accessory Electrical Equip.	4.56%	4.56%	0.00%
335.0	Misc. Power Plant Equip.	5.45%	5.45%	0.00%
336.0	Roads, Railroads & Bridges	3.15%	3.15%	0.00%
	Total Mottville	4.33%	4.33%	0.00%
Crew Service Center				
331.0	Structures & Improvements	1.64%	1.64%	0.00%
335.0	Misc. Power Plant Equip.	1.62%	1.62%	0.00%
	Total Crew Service Center	1.63%	1.63%	0.00%
Total Hydraulic Production Plant		**4.33%**	**4.33%**	**0.00%**

INDIANA MICHIGAN POWER COMPANY
COMPARE COMPANY PROPOSED DEPRECIATION RATES
TO DEPRECIATION RATES IN SETTLEMENT

IN

	ACCOUNT	COMPANY PROPOSED RATE	SETTLEMENT RATE	DIFFERENCE
OTHER PRODUCTION PLANT				
Deer Creek Solar Facility				
344.0	Generators	5.38%	5.38%	0.00%
345.0	Accessory Electric Equip.	6.57%	6.57%	0.00%
346.0	Misc. Power Plant Equip.	7.11%	7.11%	0.00%
	Total Deer Creek Solar Facility	5.51%	5.51%	0.00%
Olive Solar Facility				
341.0	Structures & Improvements	5.33%	5.33%	0.00%
344.0	Generators	5.33%	5.33%	0.00%
345.0	Accessory Electric Equip.	5.33%	5.33%	0.00%
346.0	Misc. Power Plant Equip.	5.33%	5.33%	0.00%
	Total Olive Solar Facility	5.33%	5.33%	0.00%
Twin Branch Solar Facility				
344.0	Generators	5.38%	5.38%	0.00%
Watervliet Facility				
341.0	Structures & Improvements	5.33%	5.33%	0.00%
344.0	Generators	5.33%	5.33%	0.00%
346.0	Misc. Power Plant Equip.	5.34%	5.34%	0.00%
	Total Watervliet Facility	5.33%	5.33%	0.00%
Total Other Production Plant		**5.37%**	**5.37%**	**0.00%**
Total Production Plant		**5.57%**	**5.57%**	**0.00%**
TRANSMISSION PLANT				
350.1	Land Rights	1.76%	1.76%	0.00%
352.0	Structures & Improvements	1.76%	1.76%	0.00%
353.0	Station Equipment	2.68%	2.68%	0.00%
354.0	Towers & Fixtures	2.85%	2.85%	0.00%
355.0	Poles & Fixtures	3.40%	3.40%	0.00%
356.0	OH Conductor & Devices	2.34%	2.34%	0.00%
357.0	Underground Conduit	2.25%	2.25%	0.00%
358.0	Underground Conductor	2.06%	2.06%	0.00%
359.0	Roads and Trails	1.68%	1.68%	0.00%
Total Transmission Plant		**2.67%**	**2.67%**	**0.00%**

INDIANA MICHIGAN POWER COMPANY
COMPARE COMPANY PROPOSED DEPRECIATION RATES
TO DEPRECIATION RATES IN SETTLEMENT

IN

	ACCOUNT	COMPANY PROPOSED RATE	SETTLEMENT RATE	DIFFERENCE
DISTRIBUTION PLANT - IN				
360.1	Land Rights	1.44%	1.44%	0.00%
361.0	Structures & Improvements	1.96%	1.96%	0.00%
362.0	Station Equipment	2.56%	2.56%	0.00%
363.0	Storage Battery Equipment	9.09%	9.09%	0.00%
364.0	Poles, Towers, & Fixtures	4.28%	3.56%	-0.72%
365.0	Overhead Conductor & Devices	2.86%	2.26%	-0.60%
366.0	Underground Conduit	1.66%	1.37%	-0.29%
367.0	Underground Conductor	1.96%	1.65%	-0.31%
368.0	Line Transformers	3.42%	2.43%	-0.99%
369.0	Services	2.65%	2.25%	-0.40%
370.0	Meters (3)	10.08%	10.08%	0.00%
371.0	Installations on Custs. Prem.	4.90%	4.90%	0.00%
373.0	Street Lighting & Signal Sys.	3.75%	3.75%	0.00%
Total Distribution Plant - IN		**3.14%**	**2.71%**	**-0.43%**
DISTRIBUTION PLANT - MI				
360.1	Land Rights	1.44%	1.44%	0.00%
361.0	Structures & Improvements	1.96%	1.96%	0.00%
362.0	Station Equipment	2.56%	2.56%	0.00%
363.0	Storage Battery Equipment	9.09%	9.09%	0.00%
364.0	Poles, Towers, & Fixtures	4.28%	3.56%	-0.72%
365.0	Overhead Conductor & Devices	2.86%	2.26%	-0.60%
366.0	Underground Conduit	1.66%	1.37%	-0.29%
367.0	Underground Conductor	1.96%	1.65%	-0.31%
368.0	Line Transformers	3.42%	2.43%	-0.99%
369.0	Services	2.65%	2.25%	-0.40%
370.0	Meters	10.08%	10.08%	0.00%
371.0	Installations on Custs. Prem.	4.90%	4.90%	0.00%
373.0	Street Lighting & Signal Sys.	3.75%	3.75%	0.00%
Total Distribution Plant - MI		**3.32%**	**2.89%**	**-0.43%**
Total Distribution Plant		**3.17%**	**2.73%**	**-0.44%**
GENERAL PLANT				
390.0	Structures & Improvements	2.54%	2.54%	0.00%
391.0	Office Furniture & Equipment	5.47%	5.47%	0.00%
393.0	Stores Equipment	8.08%	8.08%	0.00%
394.0	Tools Shop & Garage Equipment	7.86%	7.86%	0.00%
395.0	Laboratory Equipment	6.44%	6.44%	0.00%
396.0	Power Operated Equipment	6.45%	6.45%	0.00%
397.0	Communication Equipment	4.21%	4.21%	0.00%
398.0	Miscellaneous Equipment	3.74%	3.74%	0.00%
Total General Plant		**4.00%**	**4.00%**	**0.00%**
	Total Depreciable Plant	**4.33%**	**4.21%**	**-0.12%**

Summary of Revenue Impact Associated with Settlement Depreciation Rates

Acct	Descr	Company Proposed	OUCC Proposed	For Settlement		($M)
364.0	Poles, Towers, & Fixtures	4.28%	3.11%	3.56%	$	(1.8)
365.0	Overhead Conductor & Devices	2.86%	2.26%	2.26%	$	(2.4)
366.0	Underground Conduit	1.66%	1.37%	1.37%	$	(0.4)
367.0	Underground Conductor	1.96%	1.65%	1.65%	$	(0.8)
368.0	Line Transformers	3.42%	1.88%	2.43%	$	(3.1)
369.0	Services	2.65%	1.95%	2.25%	$	(0.7)
					$	**(9.2)**

Indiana Michigan Power Company
Proposed Revenue Allocation
Twelve Months Ending December 31, 2022

Current Class (1)	Adjusted COS Current Revenue (2)	Continuing Rider Revenue (3)	Total Revenue (4) = (2) + (3)	Current ROR % (5)	Current ROR Index (6)	Proposed Basic Rate Increase (7) = (8) - (2)	Proposed Basic Rate Revenue (8)	Rider Revenue (9)	Total Revenue (10) = (8) + (9)	% Increase (11) = (10) / (4)	Proposed ROR % (12)	Proposed ROR Index (13)
RS	566,975,891	105,400,193	672,376,084	6.72	96	(30,128,430)	536,847,461	129,985,590	666,833,052	-0.82%	5.80	100
GS	147,504,396	27,277,502	174,781,898	8.97	129	(12,782,970)	134,721,426	40,060,472	174,781,898	0.00%	7.58	131
LGS	259,294,138	49,449,286	308,743,424	5.95	85	(13,741,225)	245,552,914	64,730,880	310,283,793	0.50%	4.83	83
IP	265,654,055	55,981,667	321,635,722	7.48	107	(22,157,698)	243,496,356	78,139,365	321,635,722	0.00%	5.78	100
MS	2,561,240	495,112	3,056,352	7.20	103	(197,269)	2,363,971	640,009	3,003,981	-1.71%	5.80	100
WSS	9,781,054	1,717,081	11,498,135	6.43	92	(887,914)	8,893,140	2,604,995	11,498,135	0.00%	4.48	77
IS	245,845	15,940	261,785	11.42	164	(37,760)	208,085	27,548	235,633	-9.99%	8.57	148
EHG	575,437	104,228	679,665	6.68	96	(40,394)	535,043	144,622	679,665	0.00%	5.40	93
OL	6,482,376	(17,838)	6,464,538	9.73	140	(583,495)	5,898,881	(80,150)	5,818,731	-9.99%	8.25	142
SL	5,127,804	17,695	5,145,499	11.35	163	(519,514)	4,608,290	23,174	4,631,464	-9.99%	9.62	166
Subtotal	1,264,202,237	240,440,866	1,504,643,103	6.97	100	(81,076,669)	1,183,125,568	316,276,505	1,499,402,073	-0.35%	5.80	100
Interruptible	97,724,704	3,177,263	100,901,967			(1,382,803)	96,341,901	5,120,036	101,461,937	0.55%		
Total Basic Rates	1,361,926,941					(82,459,472)	1,279,467,469				5.78	
Riders	243,618,128	243,618,129				77,778,413	321,396,541	321,396,541				
Total	1,605,545,069		1,605,545,069			(4,681,059)	1,600,864,010		1,600,864,010	-0.29%		

Indiana Michigan Power Company
Proposed Revenue Allocation
Twelve Months Ending December 31, 2022

					Current Equalized Rate of Return						
Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Percent Increase (6)	Revenue Increase (7)	Income Increase (8)	Income (9)	ROR % (10)	Sales Revenue (11)	Current Subsidy (12)=(2)-(11)
RS	566,975,891	2,409,202,081	161,939,420	6.72	1.46	8,253,469	6,077,665	168,017,086	6.97	575,229,360	(8,253,469)
GS	147,504,396	549,517,407	49,273,709	8.97	-10.08	(14,870,803)	(10,950,517)	38,323,192	6.97	132,633,593	14,870,803
LGS	259,294,138	1,102,078,546	65,550,997	5.95	5.92	15,355,795	11,307,656	76,858,653	6.97	274,649,933	(15,355,795)
IP	265,654,055	962,166,857	71,972,825	7.48	-2.49	(6,615,598)	(4,871,574)	67,101,250	6.97	259,038,457	6,615,598
MS	2,561,240	10,392,468	747,918	7.20	-1.23	(31,438)	(23,150)	724,768	6.97	2,529,802	31,438
WSS	9,781,054	38,934,549	2,505,364	6.43	2.91	285,074	209,922	2,715,285	6.97	10,066,128	(285,074)
IS	245,845	886,927	101,280	11.42	-21.78	(53,541)	(39,426)	61,854	6.97	192,304	53,541
EHG	575,437	2,463,959	164,506	6.68	1.73	9,955	7,330	171,836	6.97	585,392	(9,955)
OL	6,482,376	28,718,744	2,793,188	9.73	-16.56	(1,073,297)	(790,351)	2,002,837	6.97	5,409,079	1,073,297
SL	5,127,804	21,198,891	2,405,957	11.35	-24.56	(1,259,616)	(927,552)	1,478,405	6.97	3,868,188	1,259,616
Total	1,264,202,237	5,125,560,428	357,455,166	6.97	0.00	0.00	0.48	357,455,166	6.97	1,264,202,237	0

Gross Rev Conversion Factor: 1.3580

Indiana Michigan Power Company
Proposed Revenue Allocation
Twelve Months Ending December 31, 2022

Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Proposed Equalized Rate of Return: Percent Increase (6)	Revenue Increase (7)	Income Increase (8)	Proposed Income (9)	ROR % (10)	Sales Revenue (11)	Retain 0% of Current Subsidy (12)	Total Bill Increase Before Mitigation (13)	Mitigation (14)	Proposed Increase (15)=(7)+(12)+(14)
RS	566,975,891	2,409,202,081	161,939,420	6.72	-5.32	(30,140,088)	(22,194,468)	139,744,952	5.80	536,835,803	0	(5,543,032)		(30,140,088)
GS	147,504,396	549,517,407	49,273,709	8.97	-16.02	(23,628,030)	(17,399,138)	31,874,571	5.80	123,876,366	0	(13,312,782)	13,312,782	(10,315,248)
LGS	259,294,138	1,102,078,546	65,550,997	5.95	-0.85	(2,207,162)	(1,625,303)	63,925,694	5.80	257,086,976	0	16,001,289	(14,460,920)	(16,668,082)
IP	265,654,055	962,166,857	71,972,825	7.48	-8.26	(21,948,895)	(16,162,662)	55,810,163	5.80	243,705,160	0	226,849	(226,849)	(22,175,744)
MS	2,561,240	10,392,468	747,918	7.20	-7.69	(197,055)	(145,106)	602,812	5.80	2,364,185	0	(52,372)		(197,055)
WSS	9,781,054	38,934,549	2,505,364	6.43	-3.43	(335,397)	(246,979)	2,258,385	5.80	9,445,657	0	700,373	(700,373)	(1,035,770)
IS	245,845	886,927	101,280	11.42	-27.53	(67,675)	(49,834)	51,446	5.80	178,170	0	(59,536)	33,384	(34,291)
EHG	575,437	2,463,959	164,506	6.68	-5.09	(29,312)	(21,585)	142,921	5.80	546,125	0	13,551	(13,551)	(42,863)
OL	6,482,376	28,718,744	2,793,188	9.73	-23.62	(1,530,964)	(1,127,367)	1,665,821	5.80	4,951,412	0	(1,602,358)	956,551	(574,413)
SL	5,127,804	21,198,891	2,405,957	11.35	-31.15	(1,597,446)	(1,176,322)	1,229,635	5.80	3,530,358	0	(1,613,011)	1,098,976	(498,470)
Total	1,264,202,237	5,125,560,428	357,455,166	6.97	-6.46	(81,682,024)	(60,148,766)	297,306,400	5.80	1,182,520,213	0	(5,241,030)	(0)	(81,682,024)
						(81,682,024)		297,306,400						

Gross Rev Conversion Factor:	1.3580
Jurisdictional Revenue Deficiency* (A-1):	(83,064,827)
*(Before TO Cost Revenue Adjustment)	
Less Juris IRP (Att. JLF-2-S P.1)	1,382,803
	(81,682,024)

Indiana Michigan Power Company
Proposed Revenue Allocation
Twelve Months Ending December 31, 2022

					Proposed Revenue Allocation							
Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Percent Increase (6)	Revenue Increase (7)	Income Increase (8)	Income (9)	Proposed Revenue (10)	Adjust for TO Cost/Revenue (11)	Adj. Proposed Revenue (12)	ROR % (13)
RS	566,975,891	2,409,202,081	161,939,420	6.72	-5.32	(30,140,088)	(22,194,468)	139,744,952	536,835,803	11,658	536,847,461	5.80
GS	147,504,396	549,517,407	49,273,709	8.97	-6.99	(10,315,248)	(7,595,911)	41,677,798	137,189,148	(2,467,723)	134,721,426	7.58
LGS	259,294,138	1,102,078,546	65,550,997	5.95	-6.43	(16,668,082)	(12,273,993)	53,277,004	242,626,056	2,926,857	245,552,914	4.83
IP	265,654,055	962,166,857	71,972,825	7.48	-8.35	(22,175,744)	(16,329,709)	55,643,116	243,478,310	18,046	243,496,356	5.78
MS	2,561,240	10,392,468	747,918	7.20	-7.69	(197,055)	(145,107)	602,811	2,364,185	(214)	2,363,971	5.80
WSS	9,781,054	38,934,549	2,505,364	6.43	-10.59	(1,035,770)	(762,717)	1,742,647	8,745,285	147,855	8,893,140	4.48
IS	245,845	886,927	101,280	11.42	-13.95	(34,291)	(25,251)	76,029	211,554	(3,469)	208,085	8.57
EHG	575,437	2,463,959	164,506	6.68	-7.45	(42,863)	(31,563)	132,943	532,574	2,469	535,043	5.40
OL	6,482,376	28,718,744	2,793,188	9.73	-8.86	(574,413)	(422,985)	2,370,203	5,907,963	(9,082)	5,898,881	8.25
SL	5,127,804	21,198,891	2,405,957	11.35	-9.72	(498,470)	(367,062)	2,038,895	4,629,334	(21,044)	4,608,290	9.62
Total	1,264,202,237	5,125,560,428	357,455,166	6.97	-6.46	(81,682,024)	(60,148,766)	297,306,400	1,182,520,213	605,355	1,183,125,568	5.80

Gross Rev Conversion Factor: 1.3580

Tariff	Total Test Year Revenue	Total Proposed Revenue	Difference	% Difference
RS (011,012,013,014,015,016,017,038,039,051,052,053,054, 063)	$ 668,456,718	$ 662,876,522	$ (5,580,196)	-0.83%
RS TOD/OPES (030, 032, 034, 036)	$ 3,739,714	$ 3,766,863	$ 27,149	0.73%
RS TOD2 (021)	$ 179,652	$ 182,679	$ 3,027	1.69%
GS Sec (211, 212, 215, 218, 281)	$ 163,890,293	$ 163,646,441	$ (243,852)	-0.15%
GS LMTOD (223, 225)	$ 403,510	$ 401,230	$ (2,279)	-0.56%
GS TOD 2 (221, 282)	$ 3,995	$ 4,088	$ 93	2.33%
GS Unmetered (204, 214)	$ 104,085	$ 102,572	$ (1,513)	-1.45%
GS TOD Sec (229)	$ 5,770,513	$ 5,709,751	$ (60,762)	-1.05%
GS TOD Pri (227)	$ 223	$ 251	$ 27	12.20%
GS Pri (217)	$ 3,805,736	$ 4,162,006	$ 356,270	9.36%
GS Sub (236)	$ 751,453	$ 682,641	$ (68,812)	-9.16%
GS Tran (239)	$ 52,090	$ 71,584	$ 19,494	37.42%
LGS Sec (240, 242)	$ 283,869,487	$ 285,131,900	$ 1,262,413	0.44%
LGS LMTOD (251)	$ 1,003,400	$ 1,031,983	$ 28,583	2.85%
LGS TOD Sec (253)	$ 7,270,143	$ 7,549,089	$ 278,946	3.84%
LGS TOD Pri (255)	$ 51,404	$ 51,195	$ (210)	-0.41%
LGS Pri (244, 246)	$ 16,243,371	$16,227,986	$ (15,385)	-0.09%
LGS Sub (248)	$ 305,619	$ 288,805	$ (16,815)	-5.50%
IP Sec (327)	$ 51,600,660	$ 52,164,397	$ 563,737	1.09%
IP Pri (322)	$ 171,849,989	$ 173,340,568	$ 1,490,579	0.87%
IP Sub (323)	$ 58,339,495	$ 58,097,217	$ (242,278)	-0.42%
IP Tran (324)	$ 19,248,087	$ 18,407,313	$ (840,774)	-4.37%
FW SL (525)	$ 759,597	$ 683,578	$ (76,019)	-10.01%
ECLS (530)	$ 3,439,112	$ 3,101,013	$ (338,099)	-9.83%
SLC (531)	$ 154,860	$ 139,438	$ (15,422)	-9.96%
SLS (533)	$ 370,975	$ 329,246	$ (41,729)	-11.25%
SLCM (733, 734, 735)	$ 420,955	$ 378,870	$ (42,085)	-10.00%
OL (090 - 121)	$ 6,464,538	$ 5,817,738	$ (646,800)	-10.01%
WSS Sec (545)	$ 6,296,020	$ 6,344,071	$ 48,051	0.76%
WSS TOD (547)	$ 487,954	$ 497,606	$ 9,652	1.98%
WSS Pri (546)	$ 4,031,420	$ 4,005,656	$ (25,764)	-0.64%
WSS Sub (542)	$ 682,742	$ 651,131	$ (31,611)	-4.63%
EHG (208)	$ 679,665	$ 679,660	$ (5)	0.00%
IS (213)	$ 261,785	$ 235,632	$ (26,153)	-9.99%
MS (543, 544)	$ 3,056,352	$ 3,003,793	$ (52,559)	-1.72%
Interruptible - Firm Portion	$ 20,597,491	$ 20,522,566	$ (74,925)	-0.36%
Total Indiana Firm Revenues	$ 1,504,643,102	$1,500,287,079	$ (4,356,023)	-0.29%
Interruptible - Jurisdictional	$ 100,901,967	$ 100,573,868	$ (328,099)	-0.33%
Total	$ 1,605,545,069	$1,600,860,946	$ (4,684,122)	-0.29%
Revenue Verification Difference		$ 3,063	$ 3,063	
Total - A-1	$ 1,605,545,069	$1,600,864,010	$ (4,681,059)	-0.29%

INDIANA MICHIGAN POWER COMPANY - INDIANA
TEST YEAR ENDED DECEMBER 31, 2022
PROFORMA RATE SUMMARY

Tariff	Total Test Year Revenue	Total 2022 Phase-In Rate Adjusted Revenue	Difference	% Difference	Total 2023 Proposed Revenue	Difference	% Difference
RS (011,012,013,014,015,016,017,038,039,051,052,053,054, 063)	$ 668,456,718	$ 662,876,522	$ (5,580,196)	-0.83%	$ 629,339,955	$ (39,116,763)	-5.85%
RS TOD/OPES (030, 032, 034, 036)	$ 3,739,714	$ 3,766,863	$ 27,149	0.73%	$ 3,556,754	$ (182,960)	-4.89%
RS TOD2 (021)	$ 179,652	$ 182,679	$ 3,027	1.69%	$ 173,946	$ (5,706)	-3.18%
GS Sec (211, 212, 215, 218, 281)	$ 163,890,293	$ 163,646,441	$ (243,852)	-0.15%	$ 153,529,689	$ (10,360,605)	-6.32%
GS LMTOD (223, 225)	$ 403,510	$ 401,230	$ (2,279)	-0.56%	$ 376,685	$ (26,825)	-6.65%
GS TOD 2 (221, 282)	$ 3,995	$ 4,088	$ 93	2.33%	$ 3,959	$ (37)	-0.92%
GS Unmetered (204, 214)	$ 104,085	$ 102,572	$ (1,513)	-1.45%	$ 98,369	$ (5,716)	-5.49%
GS TOD Sec (229)	$ 5,770,513	$ 5,709,751	$ (60,762)	-1.05%	$ 5,370,380	$ (400,132)	-6.93%
GS TOD Pri (227)	$ 223	$ 251	$ 27	12.20%	$ 246	$ 23	10.31%
GS Pri (217)	$ 3,805,736	$ 4,162,006	$ 356,270	9.36%	$ 3,811,376	$ 5,640	0.15%
GS Sub (236)	$ 751,453	$ 682,641	$ (68,812)	-9.16%	$ 639,968	$ (111,485)	-14.84%
GS Tran (239)	$ 52,090	$ 71,584	$ 19,494	37.42%	$ 62,402	$ 10,312	19.80%
LGS Sec (240, 242)	$ 283,869,487	$ 285,131,900	$ 1,262,413	0.44%	$ 267,901,875	$ (15,967,612)	-5.62%
LGS LMTOD (251)	$ 1,003,400	$ 1,031,983	$ 28,583	2.85%	$ 964,539	$ (38,860)	-3.87%
LGS TOD Sec (253)	$ 7,270,143	$ 7,549,089	$ 278,946	3.84%	$ 7,134,995	$ (135,148)	-1.86%
LGS TOD Pri (255)	$ 51,404	$ 51,195	$ (210)	-0.41%	$ 48,224	$ (3,180)	-6.19%
LGS Pri (244, 246)	$ 16,243,371	$ 16,227,986	$ (15,385)	-0.09%	$ 15,156,591	$ (1,086,781)	-6.69%
LGS Sub (248)	$ 305,619	$ 288,805	$ (16,815)	-5.50%	$ 267,808	$ (37,811)	-12.37%
IP Sec (327)	$ 51,600,660	$ 52,164,397	$ 563,737	1.09%	$ 48,717,528	$ (2,883,131)	-5.59%
IP Pri (322)	$ 171,849,989	$ 173,340,568	$ 1,490,579	0.87%	$ 160,875,073	$ (10,974,916)	-6.39%
IP Sub (323)	$ 58,339,495	$ 58,097,217	$ (242,278)	-0.42%	$ 53,458,232	$ (4,881,263)	-8.37%
IP Tran (324)	$ 19,248,087	$ 18,407,313	$ (840,774)	-4.37%	$ 16,856,976	$ (2,391,111)	-12.42%
FW SL (525)	$ 759,597	$ 683,578	$ (76,019)	-10.01%	$ 674,103	$ (85,494)	-11.26%
ECLS (530)	$ 3,439,112	$ 3,101,013	$ (338,099)	-9.83%	$ 3,092,748	$ (346,364)	-10.07%
SLC (531)	$ 154,860	$ 139,438	$ (15,422)	-9.96%	$ 138,313	$ (16,547)	-10.69%
SLS (533)	$ 370,975	$ 329,246	$ (41,729)	-11.25%	$ 328,094	$ (42,881)	-11.56%
SLCM (733, 734, 735)	$ 420,955	$ 378,870	$ (42,085)	-10.00%	$ 375,222	$ (45,733)	-10.86%
OL (090 - 121)	$ 6,464,538	$ 5,817,738	$ (646,800)	-10.01%	$ 5,867,669	$ (596,869)	-9.23%
WSS Sec (545)	$ 6,296,020	$ 6,344,071	$ 48,051	0.76%	$ 5,936,844	$ (359,175)	-5.70%
WSS TOD (547)	$ 487,954	$ 497,606	$ 9,652	1.98%	$ 463,178	$ (24,776)	-5.08%
WSS Pri (546)	$ 4,031,420	$ 4,005,656	$ (25,764)	-0.64%	$ 3,711,178	$ (320,241)	-7.94%
WSS Sub (542)	$ 682,742	$ 651,131	$ (31,611)	-4.63%	$ 594,763	$ (87,979)	-12.89%
EHG (208)	$ 679,665	$ 679,660	$ (5)	0.00%	$ 641,117	$ (38,549)	-5.67%
IS (213)	$ 261,785	$ 235,632	$ (26,153)	-9.99%	$ 229,239	$ (32,545)	-12.43%
MS (543, 544)	$ 3,056,352	$ 3,003,793	$ (52,559)	-1.72%	$ 2,826,710	$ (229,643)	-7.51%
Interruptible - Firm Portion	$ 20,597,491	$ 20,522,566	$ (74,925)	-0.36%	$ 18,814,387	$ (1,783,104)	-8.66%
Total Indiana Firm Revenues	$ 1,504,643,102	$ 1,500,287,079	$ (4,356,023)	-0.29%	$ 1,412,039,134	$ (92,603,968)	-6.15%
Interruptible - Jurisdictional	$ 100,901,967	$ 100,573,868	$ (328,099)	-0.33%	$ 98,798,191	$ (2,103,776)	-2.08%
Total	$ 1,605,545,069	$ 1,600,860,946	$ (4,684,122)	-0.29%	$ 1,510,837,325	$ (94,707,744)	-5.90%

Description (1)	Current Indiana Jurisdictional Revenue (2)	Proposed Indiana Jurisdictional Revenue (3)	Change in Jurisdictional Revenue (4) = (3) - (2)
Base Revenue	$ 1,312,316,436	$ 1,279,464,405	$ (32,852,031)
Fuel Cost Adjustment Rider	$ 1,646,697	$ -	$ (1,646,697)
OSS & PJM Cost Rider	$ 288,000,774	$ 265,317,071	$ (22,683,702)
DSM Rider	$ 18,155,471	$ 9,872,614	$ (8,282,857)
Life Cycle Management Rider	$ 4,556,275	$ 138,725	$ (4,417,551)
Tax Rider	$ 15,093,489	$ (34,782,795)	$ (49,876,284)
Solar Power Rider	$ 1,959,758	$ 2,141,350	$ 181,591
Environmental Cost Rider	$ (9,067,145)	$ 1,310,171	$ 10,377,316
Resource Adequacy Rider	$ (9,769,523)	$ 65,131,690	$ 74,901,213
Phase-In Rider	$ (17,347,163)	$ 12,267,716	$ 29,614,879
Total including Juris IRP	$ 1,605,545,069	$ 1,600,860,946	$ (4,684,122)
			-0.29%

Line No.	Class Description	Base Revenue	Fuel Cost Adj Rider	DSM Rider	OSS & PJM Cost Rider	Life Cycle Mgmt Rider	Tax Rider	Solar Power Rider	Env. Cost Rider	Resource Adeq Rider	Phase-In Rider	Present Revenue
1	RS	$ 547,800,057	$ 510,881	$ 6,050,518	$ 120,732,489	$ 1,921,080	$ 6,350,119	$ 831,764	$ (3,132,838)	$ (4,129,266)	$ (8,478,085)	$ 668,456,718
2	RS TOD	$ 2,983,939	$ 3,201	$ 37,759	$ 756,399	$ 12,036	$ 39,784	$ 5,211	$ (19,627)	$ (25,870)	$ (53,116)	$ 3,739,714
3	RS TOD 2	$ 147,981	$ 133	$ 1,827	$ 31,439	$ 500	$ 1,654	$ 217	$ (816)	$ (1,075)	$ (2,208)	$ 179,652
4	Total Residential	$ 550,931,977	$ 514,214	$ 6,090,103	$ 121,520,327	$ 1,933,616	$ 6,391,557	$ 837,192	$ (3,153,281)	$ (4,156,212)	$ (8,533,408)	$ 672,376,084
5	GS Sec	$ 133,392,456	$ 124,539	$ 2,329,390	$ 29,403,544	$ 468,308	$ 1,549,018	$ 202,762	$ (763,702)	$ (1,006,604)	$ (1,809,417)	$ 163,890,293
6	GS LMTOD	$ 308,186	$ 389	$ 7,338	$ 91,843	$ 1,463	$ 4,838	$ 633	$ (2,385)	$ (3,144)	$ (5,652)	$ 403,510
7	GS TOD 2	$ 3,498	$ 2	$ 33	$ 484	$ 8	$ 26	$ 3	$ (13)	$ (17)	$ (30)	$ 3,995
8	GS Unmetered	$ 89,018	$ 67	$ -	$ 15,727	$ 250	$ 829	$ 108	$ (408)	$ (538)	$ (968)	$ 104,085
9	GS TOD Sec	$ 4,452,803	$ 5,378	$ 101,219	$ 1,269,829	$ 20,224	$ 66,896	$ 8,757	$ (32,981)	$ (43,471)	$ (78,142)	$ 5,770,513
10	GS TOD Pri	$ 207	$ 0	$ 1	$ 16	$ 0	$ 1	$ 0	$ (0)	$ (1)	$ (1)	$ 223
11	GS Pri	$ 2,991,317	$ 3,372	$ 51,776	$ 796,082	$ 12,679	$ 41,939	$ 5,490	$ (20,677)	$ (27,253)	$ (48,989)	$ 3,805,736
12	GS Sub	$ 551,591	$ 815	$ 15,436	$ 192,512	$ 3,066	$ 10,142	$ 1,328	$ (5,000)	$ (6,590)	$ (11,847)	$ 751,453
20	GS Tran	$ 40,724	$ 47	$ 759	$ 11,072	$ 176	$ 583	$ 76	$ (288)	$ (379)	$ (681)	$ 52,090
13	Total GS	$ 141,829,800	$ 134,609	$ 2,505,953	$ 31,781,110	$ 506,175	$ 1,674,271	$ 219,157	$ (825,454)	$ (1,087,998)	$ (1,955,726)	$ 174,781,897
14	LGS Sec	$ 227,528,180	$ 300,988	$ 4,331,025	$ 54,535,398	$ 868,170	$ 2,848,946	$ 370,869	$ (1,852,780)	$ (1,854,343)	$ (3,206,965)	$ 283,869,487
15	LGS LMTOD	$ 803,040	$ 1,069	$ 17,030	$ 191,836	$ 3,048	$ 10,035	$ 1,307	$ (6,599)	$ (6,528)	$ (10,839)	$ 1,003,400
16	LGS TOD Sec	$ 6,115,502	$ 8,047	$ 116,213	$ 1,099,642	$ 17,369	$ 56,998	$ 7,420	$ (49,704)	$ (37,099)	$ (64,244)	$ 7,270,143
17	LGS TOD Pri	$ 42,953	$ 56	$ 949	$ 7,935	$ 125	$ 412	$ 54	$ (348)	$ (268)	$ (464)	$ 51,404
18	LGS Pri	$ 12,865,870	$ 19,059	$ 275,117	$ 3,258,864	$ 51,805	$ 170,001	$ 22,130	$ (117,415)	$ (110,652)	$ (191,410)	$ 16,243,371
19	LGS Sub	$ 242,569	$ 432	$ 6,166	$ 60,189	$ 951	$ 3,122	$ 406	$ (2,665)	$ (2,032)	$ (3,518)	$ 305,619
21	Total LGS	$ 247,598,115	$ 329,651	$ 4,746,500	$ 59,153,864	$ 941,468	$ 3,089,513	$ 402,186	$ (2,029,510)	$ (2,010,922)	$ (3,477,441)	$ 308,743,424
22	IP Sec	$ 41,121,616	$ 57,980	$ 666,166	$ 10,112,158	$ 153,685	$ 528,963	$ 65,525	$ (358,205)	$ (328,815)	$ (418,412)	$ 51,600,660
23	IP Pri	$ 134,834,168	$ 215,653	$ 2,285,860	$ 35,844,169	$ 544,094	$ 1,872,694	$ 231,978	$ (1,332,950)	$ (1,164,107)	$ (1,481,570)	$ 171,849,989
24	IP Sub	$ 44,764,502	$ 84,636	$ 748,504	$ 13,264,259	$ 201,025	$ 691,901	$ 85,708	$ (523,424)	$ (430,100)	$ (547,516)	$ 58,339,495
25	IP Tran	$ 14,462,351	$ 24,197	$ 280,362	$ 4,630,023	$ 70,522	$ 242,728	$ 30,068	$ (149,340)	$ (150,885)	$ (191,939)	$ 19,248,087
26	Total IP	$ 235,182,638	$ 382,466	$ 3,980,891	$ 63,850,609	$ 969,326	$ 3,336,285	$ 413,279	$ (2,363,919)	$ (2,073,907)	$ (2,639,437)	$ 301,038,231
27	FW SL	$ 726,965	$ 2,723	$ 40,667	$ 41,367	$ 495	$ 1,620	$ 180	$ (16,970)	$ (1,035)	$ (36,416)	$ 759,597
28	ECLS	$ 3,410,644	$ 2,376	$ 35,477	$ 36,086	$ 432	$ 1,414	$ 157	$ (14,803)	$ (903)	$ (31,766)	$ 3,439,112
29	SLC	$ 150,990	$ 323	$ 4,824	$ 4,913	$ 59	$ 192	$ 21	$ (2,015)	$ (123)	$ (4,325)	$ 154,860
30	SLS	$ 367,006	$ 331	$ 4,946	$ 5,031	$ 60	$ 197	$ 22	$ (2,064)	$ (126)	$ (4,429)	$ 370,975
31	SLCM	$ 408,397	$ 1,048	$ 15,651	$ 15,925	$ 191	$ 624	$ 69	$ (6,533)	$ (399)	$ (14,019)	$ 420,955
32	Total SL	$ 5,064,001	$ 6,802	$ 101,567	$ 103,321	$ 1,237	$ 4,047	$ 450	$ (42,385)	$ (2,586)	$ (90,954)	$ 5,145,499
33	OL	$ 6,549,214	$ 4,640	$ -	$ 68,569	$ 805	$ 2,608	$ 345	$ (28,916)	$ (1,687)	$ (131,040)	$ 6,464,538
34	WSS Sec	$ 5,150,113	$ 8,118	$ 114,758	$ 1,090,388	$ 16,973	$ 56,757	$ 7,313	$ (50,316)	$ (36,496)	$ (61,587)	$ 6,296,020
35	WSS TOD	$ 390,778	$ 686	$ 10,002	$ 92,183	$ 1,435	$ 4,798	$ 618	$ (4,254)	$ (3,085)	$ (5,207)	$ 487,954
36	WSS Pri	$ 3,225,101	$ 5,870	$ 60,664	$ 788,492	$ 12,274	$ 41,043	$ 5,288	$ (36,385)	$ (26,391)	$ (44,535)	$ 4,031,420
37	WSS Sub	$ 528,132	$ 1,124	$ 11,879	$ 150,931	$ 2,349	$ 7,856	$ 1,012	$ (6,965)	$ (5,052)	$ (8,525)	$ 682,742
38	Total WSS	$ 9,294,125	$ 15,798	$ 197,302	$ 2,121,993	$ 33,032	$ 110,454	$ 14,231	$ (97,920)	$ (71,025)	$ (119,854)	$ 11,498,135
39	EHG	$ 552,188	$ 543	$ 11,466	$ 121,090	$ 1,944	$ 6,372	$ 837	$ (3,335)	$ (4,131)	$ (7,307)	$ 679,665
40	IS	$ 243,653	$ 151	$ 1,458	$ 19,956	$ 313	$ 1,037	$ 140	$ (933)	$ (668)	$ (3,323)	$ 261,785
41	MS	$ 2,451,407	$ 2,675	$ 50,083	$ 579,136	$ 9,219	$ 30,465	$ 3,979	$ (16,470)	$ (19,764)	$ (34,378)	$ 3,056,352
42	IRP Firm	$ 16,169,140	$ 36,520	$ 210,563	$ 4,407,480	$ 66,244	$ 228,002	$ 28,243	$ (226,334)	$ (141,731)	$ (180,636)	$ 20,597,491
43	IRP Interruptible *	$ 138,588,991	$ 314,260	$ 373,134	$ 6,049,007	$ 119,256	$ 309,606	$ 50,957	$ (400,973)	$ (255,291)	$ (245,664)	$ 144,903,284
44	Total IRP	$ 154,758,131	$ 350,780	$ 583,697	$ 10,456,487	$ 185,500	$ 537,608	$ 79,201	$ (627,307)	$ (397,021)	$ (426,300)	$ 165,500,775
45	**Total Indiana**	$ 1,354,455,249	$ 1,742,330	$ 18,269,020	$ 289,776,462	$ 4,582,635	$ 15,184,216	$ 1,970,997	$ (9,189,432)	$ (9,825,921)	$ (17,419,170)	$ 1,649,546,386
46	Juris IRP	$ 96,450,178	$ 218,627	$ 259,584	$ 4,273,319	$ 92,896	$ 218,879	$ 39,719	$ (278,686)	$ (198,893)	$ (173,656)	$ 100,901,967
47	Non-Juris IRP	$ 42,138,813	$ 95,633	$ 113,549	$ 1,775,688	$ 26,360	$ 90,727	$ 11,239	$ (122,287)	$ (56,398)	$ (72,007)	$ 44,001,317
48	**Indiana Juris**	$ 1,312,316,436	$ 1,646,697	$ 18,155,471	$ 288,000,774	$ 4,556,275	$ 15,093,489	$ 1,959,758	$ (9,067,145)	$ (9,769,523)	$ (17,347,163)	$ 1,605,545,069

*IRP Interruptible is not jurisdictionalized

Line No.	Class Description	Base Revenue	Fuel Cost Adj Rider	DSM Rider	OSS & PJM Cost Rider	Life Cycle Mgmt Rider	Tax Rider	Solar Power Rider	Env. Cost Rider	Resource Adeq Rider	Phase-In Rider	Proposed Revenue	Revenue Increase	Percent Increase
1	RS	$ 533,733,736	$ -	$ 4,943,910	$ 108,640,240	$ 54,888	$ (14,080,883)	$ 878,208	$ 447,548	$ 26,633,346	$ 1,625,529	$ 662,876,522	$ (5,580,196)	-0.83%
2	RS TOD	$ 2,957,895	$ -	$ 30,853	$ 680,640	$ 344	$ (88,218)	$ 5,502	$ 2,804	$ 166,860	$ 10,184	$ 3,766,863	$ 27,149	0.73%
3	RS TOD 2	$ 148,844	$ -	$ 1,493	$ 28,290	$ 14	$ (3,667)	$ 229	$ 117	$ 6,935	$ 423	$ 182,679	$ 3,027	1.69%
4	Total Residential	$ 536,840,475	$ -	$ 4,976,255	$ 109,349,170	$ 55,246	$ (14,172,768)	$ 883,939	$ 450,469	$ 26,807,142	$ 1,636,137	$ 666,826,065	$ (5,550,019)	-0.83%
5	GS Sec	$ 126,395,892	$ -	$ 845,486	$ 31,495,729	$ 17,466	$ (4,043,867)	$ 251,025	$ 109,100	$ 7,649,531	$ 926,077	$ 163,646,441	$ (243,852)	-0.15%
6	GS LMTOD	$ 314,356	$ -	$ 2,663	$ 71,502	$ 39	$ (9,352)	$ 582	$ 341	$ 17,688	$ 3,411	$ 401,230	$ (2,279)	-0.56%
7	GS TOD 2	$ 3,632	$ -	$ 12	$ 377	$ 0	$ (49)	$ 3	$ 2	$ 93	$ 18	$ 4,088	$ 93	2.33%
8	GS Unmetered	$ 88,152	$ -	$ -	$ 12,244	$ 7	$ (1,601)	$ 100	$ 58	$ 3,029	$ 584	$ 102,572	$ (1,513)	-1.45%
9	GS TOD Sec	$ 4,508,707	$ -	$ 36,737	$ 988,598	$ 533	$ (129,303)	$ 8,045	$ 4,712	$ 244,560	$ 47,161	$ 5,709,751	$ (60,762)	-1.05%
10	GS TOD Pri	$ 236	$ -	$ 0	$ 12	$ 0	$ (2)	$ 0	$ 0	$ 3	$ 1	$ 251	$ 27	12.20%
11	GS Pri	$ 2,836,693	$ -	$ 18,835	$ 1,144,989	$ 651	$ (145,140)	$ 8,991	$ 2,954	$ 274,585	$ 19,446	$ 4,162,006	$ 356,270	9.36%
12	GS Sub	$ 537,297	$ -	$ 5,602	$ 116,354	$ 70	$ (15,506)	$ 960	$ 714	$ 29,335	$ 7,814	$ 682,641	$ (68,812)	-9.16%
20	GS Tran	$ 35,126	$ -	$ 276	$ 32,335	$ 18	$ (4,021)	$ 249	$ 41	$ 7,608	$ (48)	$ 71,584	$ 19,494	37.42%
13	Total GS	$ 134,720,091	$ -	$ 909,612	$ 33,862,142	$ 18,784	$ (4,348,841)	$ 269,956	$ 117,922	$ 8,226,434	$ 1,004,464	$ 174,780,563	$ (1,334)	0.00%
14	LGS Sec	$ 225,798,414	$ -	$ 1,851,172	$ 48,244,291	$ 28,736	$ (6,379,311)	$ 395,115	$ 268,896	$ 12,068,967	$ 2,855,621	$ 285,131,900	$ 1,262,413	0.44%
15	LGS LMTOD	$ 793,462	$ -	$ 7,137	$ 196,465	$ 106	$ (25,697)	$ 1,599	$ 936	$ 48,602	$ 9,372	$ 1,031,983	$ 28,583	2.85%
16	LGS TOD Sec	$ 6,150,754	$ -	$ 48,706	$ 1,121,432	$ 675	$ (149,746)	$ 9,275	$ 7,049	$ 283,303	$ 77,641	$ 7,549,089	$ 278,946	3.84%
17	LGS TOD Pri	$ 41,049	$ -	$ 398	$ 8,124	$ 5	$ (1,082)	$ 67	$ 49	$ 2,046	$ 538	$ 51,195	$ (210)	-0.41%
18	LGS Pri	$ 12,547,005	$ -	$ 116,759	$ 2,987,819	$ 1,782	$ (395,542)	$ 24,499	$ 16,907	$ 748,322	$ 180,435	$ 16,227,986	$ (15,385)	-0.09%
19	LGS Sub	$ 219,394	$ -	$ 2,654	$ 54,861	$ 33	$ (7,405)	$ 459	$ 388	$ 14,010	$ 4,411	$ 288,805	$ (16,815)	-5.50%
21	Total LGS	$ 245,550,078	$ -	$ 2,026,826	$ 52,612,992	$ 31,336	$ (6,958,782)	$ 431,013	$ 294,227	$ 13,165,250	$ 3,128,017	$ 310,280,958	$ 1,537,534	0.50%
22	IP Sec	$ 40,689,127	$ -	$ 268,866	$ 9,281,365	$ 4,380	$ (1,228,680)	$ 73,370	$ 52,260	$ 2,232,868	$ 790,839	$ 52,164,397	$ 563,737	1.09%
23	IP Pri	$ 132,230,671	$ -	$ 929,030	$ 33,152,428	$ 15,704	$ (4,405,024)	$ 263,045	$ 195,565	$ 8,005,208	$ 2,953,941	$ 173,340,568	$ 1,490,579	0.87%
24	IP Sub	$ 43,045,181	$ -	$ 304,589	$ 12,092,334	$ 5,763	$ (1,616,497)	$ 96,529	$ 76,675	$ 2,937,644	$ 1,154,999	$ 58,097,217	$ (242,278)	-0.42%
25	IP Tran	$ 13,147,084	$ -	$ 111,279	$ 4,303,947	$ 2,013	$ (564,673)	$ 33,719	$ 21,450	$ 1,026,176	$ 326,319	$ 18,407,313	$ (840,774)	-4.37%
26	Total IP	$ 229,112,064	$ -	$ 1,613,763	$ 58,830,074	$ 27,861	$ (7,814,874)	$ 466,664	$ 345,950	$ 14,201,896	$ 5,226,098	$ 302,009,495	$ 971,264	0.32%
27	FW SL	$ 674,299	$ -	$ 17,044	$ (20,188)	$ -	$ (1,891)	$ 113	$ 2,386	$ 3,579	$ 8,237	$ 683,578	$ (76,019)	-10.01%
28	ECLS	$ 3,092,918	$ -	$ 14,869	$ (17,611)	$ -	$ (1,649)	$ 98	$ 2,081	$ 3,122	$ 7,186	$ 3,101,013	$ (338,099)	-9.83%
29	SLC	$ 138,338	$ -	$ 2,022	$ (2,398)	$ -	$ (225)	$ 13	$ 283	$ 425	$ 978	$ 139,438	$ (15,422)	-9.96%
30	SLS	$ 328,118	$ -	$ 2,073	$ (2,455)	$ -	$ (230)	$ 14	$ 290	$ 435	$ 1,002	$ 329,246	$ (41,729)	-11.25%
31	SLCM	$ 375,299	$ -	$ 6,560	$ (7,772)	$ -	$ (728)	$ 43	$ 918	$ 1,378	$ 3,171	$ 378,870	$ (42,085)	-10.00%
32	Total SL	$ 4,608,972	$ -	$ 42,567	$ (50,424)	$ -	$ (4,722)	$ 281	$ 5,959	$ 8,938	$ 20,574	$ 4,632,145	$ (513,354)	-9.98%
33	OL	$ 5,897,889	$ -	$ -	$ (35,358)	$ -	$ (3,106)	$ 192	$ 4,065	$ 5,867	$ (51,810)	$ 5,817,738	$ (646,800)	-10.01%
34	WSS Sec	$ 4,999,945	$ -	$ 48,112	$ 1,065,498	$ 604	$ (143,100)	$ 8,923	$ 7,111	$ 270,635	$ 86,343	$ 6,344,071	$ 48,051	0.76%
35	WSS TOD	$ 383,847	$ -	$ 4,192	$ 90,079	$ 51	$ (12,098)	$ 754	$ 601	$ 22,880	$ 7,300	$ 497,606	$ 9,652	1.98%
36	WSS Pri	$ 3,042,936	$ -	$ 25,534	$ 770,493	$ 437	$ (103,480)	$ 6,452	$ 5,142	$ 195,704	$ 62,437	$ 4,005,656	$ (25,764)	-0.64%
37	WSS Sub	$ 466,739	$ -	$ 4,998	$ 147,485	$ 84	$ (19,808)	$ 1,235	$ 984	$ 37,461	$ 11,951	$ 651,131	$ (31,611)	-4.63%
38	Total WSS	$ 8,893,468	$ -	$ 82,836	$ 2,073,555	$ 1,175	$ (278,485)	$ 17,364	$ 13,839	$ 526,679	$ 168,031	$ 11,498,464	$ 328	0.00%
39	EHG	$ 535,037	$ -	$ 4,161	$ 122,173	$ 54	$ (15,794)	$ 972	$ 476	$ 29,860	$ 2,720	$ 679,660	$ (5)	0.00%
40	IS	$ 208,084	$ -	$ 529	$ 24,720	$ 12	$ (3,260)	$ 204	$ 132	$ 6,166	$ (956)	$ 235,632	$ (26,153)	-9.99%
41	MS	$ 2,363,784	$ -	$ 20,990	$ 529,571	$ 287	$ (68,932)	$ 4,289	$ 2,343	$ 130,392	$ 21,069	$ 3,003,793	$ (52,559)	-1.72%
42	IRP Firm	$ 15,280,632	$ -	$ 87,268	$ 4,124,046	$ 2,013	$ (564,654)	$ 33,718	$ 33,455	$ 1,026,141	$ 499,946	$ 20,522,566	$ (74,925)	-0.36%
43	IRP Interruptible *	$ 137,146,941	$ -	$ 154,962	$ 5,466,196	$ 2,766	$ (775,966)	$ 46,337	$ 59,414	$ 1,410,156	$ 881,397	$ 144,392,204	$ (511,080)	-0.35%
44	Total IRP	$ 152,427,573	$ -	$ 242,230	$ 9,590,243	$ 4,779	$ (1,340,621)	$ 80,055	$ 92,870	$ 2,436,297	$ 1,381,344	$ 164,914,770	$ (586,005)	-0.35%
45	**Total Indiana**	$ 1,321,157,515	$ -	$ 9,919,771	$ 266,908,858	$ 139,535	$ (35,010,184)	$ 2,154,928	$ 1,328,252	$ 65,544,922	$ 12,535,686	$ 1,644,679,283	$ (4,867,103)	-0.30%
46	Juris IRP	$ 95,453,832	$ -	$ 107,805	$ 3,874,409	$ 1,956	$ (548,577)	$ 32,758	$ 41,334	$ 996,924	$ 613,427	$ 100,573,868	$ (328,099)	-0.33%
47	Non-Juris IRP	$ 41,693,109	$ -	$ 47,157	$ 1,591,787.04	$ 811	$ (227,389)	$ 13,578	$ 18,081	$ 413,232	$ 267,970.61	$ 43,818,336	$ (182,981)	-0.42%
48	**Indiana Juris**	$ 1,279,464,405	$ -	$ 9,872,614	$ 265,317,071	$ 138,725	$ (34,782,795)	$ 2,141,350	$ 1,310,171	$ 65,131,690	$ 12,267,716	$ 1,600,860,946	$ (4,684,122)	-0.29%

*IRP Interruptible is not jurisdictionalized

Line No.	Class Description	Metered Energy	Current Billing Energy	Proposed Billing Energy	No. of Customers	No. of Bills
1	RS	4,222,153,829	4,222,153,829	4,222,153,829	4,903,989	4,868,440
2	RS TOD	26,452,128	26,452,128	26,452,128	17,553	17,477
3	RS TOD 2	1,099,470	1,099,470	1,099,470	1,636	1,625
4	Total Residential	4,249,705,427	4,249,705,427	4,249,705,427	4,923,178	4,887,542
5	GS Sec	1,029,313,784	1,029,247,554	1,029,247,554	598,209	596,292
6	GS LMTOD	3,214,893	3,214,893	3,214,893	1,241	1,240
7	GS TOD 2	16,955	16,955	16,955	28	28
8	GS Unmetered	550,524	550,524	550,524	2,807	3,091
9	GS TOD Sec	44,452,316	44,449,361	44,449,361	19,036	18,975
10	GS TOD Pri	553	553	553	1	1
11	GS Pri	27,865,895	27,866,219	27,866,219	564	563
12	GS Sub	6,738,717	6,738,742	6,738,742	48	48
20	GS Tran	387,555	387,555	387,555	24	23
13	Total GS	1,112,541,192	1,112,472,356	1,112,472,356	621,958	620,261
14	LGS Sec	2,536,925,235	2,487,504,788	2,536,755,288	57,667	57,629
15	LGS LMTOD	8,833,465	8,833,465	8,833,465	568	567
16	LGS TOD Sec	66,503,602	66,503,602	66,503,602	6,031	6,007
17	LGS TOD Pri	465,405	465,405	465,405	12	12
18	LGS Pri	159,497,000	157,514,748	159,501,965	1,080	1,079
19	LGS Sub	3,663,256	3,566,907	3,663,256	12	12
21	Total LGS	2,775,887,963	2,724,388,915	2,775,722,981	65,370	65,306
22	IP Sec	493,611,326	479,177,550	493,018,114	891	890
23	IP Pri	1,844,949,386	1,782,256,210	1,844,949,386	1,649	1,647
24	IP Sub	722,738,046	699,468,909	723,349,878	228	227
25	IP Tran	202,170,793	199,973,775	202,357,518	72	72
26	Total IP	3,263,469,551	3,160,876,444	3,263,674,896	2,840	2,836
27	FW SL	22,506,643	22,506,643	22,506,643	12	0
28	ECLS	19,633,062	19,633,062	19,633,062	1,347	0
29	SLC	2,672,813	2,672,813	2,672,813	1,478	0
30	SLS	2,737,356	2,737,356	2,737,356	460	0
31	SLCM	8,664,180	8,664,180	8,664,180	9,509	9506
32	Total SL	56,214,054	56,214,054	56,214,054	12,806	9,506
33	OL	38,349,500	38,349,500	38,349,500	0	0
34	WSS Sec	67,636,445	67,088,410	67,088,410	5,063	5,059
35	WSS TOD	5,671,744	5,671,744	5,671,744	48	48
36	WSS Pri	49,420,825	48,513,602	48,513,602	169	169
37	WSS Sub	9,333,155	9,286,324	9,286,324	65	65
38	Total WSS	132,062,169	130,560,080	130,560,080	5,345	5,341
39	EHG	4,489,291	4,489,291	4,489,291	1,623	1,623
40	IS	1,248,480	1,248,480	1,248,480	803	420
41	MS	22,107,814	22,107,814	22,107,814	3,679	3,680
42	IRP Firm	315,617,856	301,821,230	315,617,856	60	60
43	IRP Interruptible *	2,623,738,813	2,597,189,866	2,622,786,630	24	12
44	Total IRP	2,939,356,669	2,899,011,096	2,938,404,486	84	72
45	**Total Indiana**	14,595,432,110	14,399,423,457	14,592,949,365	5,637,686	5,596,587
46	Juris IRP					
47	Non-Juris IRP					
48	**Indiana Juris**					

*IRP Interruptible is not jurisdictionalized

Tariff		2023 Phase-in Rate Credit
RS (011,012,013,014,015,016,017,038,039,051,052,053,054, 063)	$	(7,392,991)
RS TOD/OPES (030, 032, 034, 036)	$	(46,318)
RS TOD2 (021)	$	(1,925)
GS Sec (211, 212, 215, 218, 281)	$	(2,122,412)
GS LMTOD (223, 225)	$	(4,909)
GS TOD 2 (221, 282)	$	(26)
GS Unmetered (204, 214)	$	(841)
GS TOD Sec (229)	$	(67,874)
GS TOD Pri (227)	$	(1)
GS Pri (217)	$	(76,166)
GS Sub (236)	$	(8,137)
GS Tran (239)	$	(2,110)
LGS Sec (240, 242)	$	(3,347,702)
LGS LMTOD (251)	$	(13,489)
LGS TOD Sec (253)	$	(78,583)
LGS TOD Pri (255)	$	(568)
LGS Pri (244, 246)	$	(207,570)
LGS Sub (248)	$	(3,886)
IP Sec (327)	$	(619,815)
IP Pri (322)	$	(2,222,142)
IP Sub (323)	$	(815,452)
IP Tran (324)	$	(284,853)
FW SL (525)	$	(990)
ECLS (530)	$	(864)
SLC (531)	$	(118)
SLS (533)	$	(120)
SLCM (733, 734, 735)	$	(381)
OL (090 - 121)	$	(1,649)
WSS Sec (545)	$	(75,072)
WSS TOD (547)	$	(6,347)
WSS Pri (546)	$	(54,287)
WSS Sub (542)	$	(10,391)
EHG (208)	$	(8,288)
IS (213)	$	(1,710)
MS (543, 544)	$	(36,190)
Subtotal	$	(17,514,179)
Interruptible - Firm Portion	$	(284,843)
Interruptible - Jurisdictional		($276,733)
Total	$	(18,075,755)
Revenue Target from WP-JLF-6-S	$	(18,075,753)
Revenue Verification Difference	$	(2)

RESIDENTIAL SERVICE (011, 012, 013, 014, 015, 016, 017, 038, 039, 045, 046, 047, 051, 052, 053, 054, 063)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description	Total	Rate	Revenue	Total	Rate	Revenue	Rate	Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
Billing kWh								
All kWh	4,173,121,801			4,173,121,801				
First 900 kWh	3,078,510,192	$0.11482	$ 353,466,374	3,078,510,192	$0.11136	$ 342,822,895	$0.11136	$ 342,822,895
Over 900 kWh	1,094,611,609	$0.10809	$ 118,316,569	1,094,611,609	$0.10464	$ 114,540,159	$0.10464	$ 114,540,159
Storage Water Heating kWh	40,790,728	$0.05188	$ 2,116,223	40,790,728	$0.06095	$ 2,486,195	$0.06095	$ 2,486,195
Metered kWh	4,213,912,529			4,213,912,529				
Customer Charge	4,858,689	$15.00	$ 72,880,336	4,858,689	$15.00	$ 72,880,336	$15.00	$ 72,880,336
Cogen Customer Charge	12	$2.40	$ 29	12	$1.05	$ 13	$1.05	$ 13
Number of Customers	4,894,238			4,894,238				
Employee Discount - All kWh	13,927,148			13,927,148				
First 900 kWh	10,225,464	-$0.00998	$ (102,050)	10,225,464	-$0.00998	$ (102,050)	-$0.00998	$ (102,050)
Over 900 kWh	3,701,684	-$0.00998	$ (36,943)	3,701,684	-$0.00998	$ (36,943)	-$0.00998	$ (36,943)
Employee Discount - Storage Water Htg	594,396	-$0.00460	$ (2,734)	594,396	-$0.00460	$ (2,734)	-$0.00460	$ (2,734)
EZ Bill Revenues								
Billing kWh	8,241,300		$ 1,162,254	8,241,300		$ 1,145,866		$ 1,145,866
Metered kWh	8,241,300			8,241,300				
Number of Customers	9,751			9,751				
Number of Bills	9,751			9,751				
Fuel			$ 510,881					
Subtotal			$ 548,310,938			$ 533,733,736		$ 533,733,736
DSM/EE Program Cost Rider - Non-Opt Out **	3,980,603,644	$0.001520	$ 6,050,518	3,980,603,644	$0.001242	$ 4,943,910	$0.001242	$ 4,943,910
Off-System Sales & PJM Cost Rider	4,222,153,829	$0.028595	$ 120,732,489	4,222,153,829	$0.025731	$ 108,640,240	$0.025731	$ 108,640,240
Life Cycle Management Rider	4,222,153,829	$0.000455	$ 1,921,080	4,222,153,829	$0.000013	$ 54,888	$0.000013	$ 54,888
Tax Rider	4,222,153,829	$0.001504	$ 6,350,119	4,222,153,829	-$0.003335	$ (14,080,883)	-$0.003335	$ (14,080,883)
Solar Power Rider	4,222,153,829	$0.000197	$ 831,764	4,222,153,829	$0.000208	$ 878,208	$0.000208	$ 878,208
Environmental Cost Rider	4,222,153,829	-$0.000742	$ (3,132,838)	4,222,153,829	$0.000106	$ 447,548	$0.001786	$ 7,540,767
Resource Adequacy Rider	4,222,153,829	-$0.000978	$ (4,129,266)	4,222,153,829	$0.006308	$ 26,633,346	-$0.001179	$ (4,977,919)
Phase in Rate	4,222,153,829	-$0.002008	$ (8,478,085)	4,222,153,829	$0.000385	$ 1,625,529	-$0.001751	$ (7,392,991)
Total			$ 668,456,718			$ 662,876,522		$ 629,339,955

** DSM/EE Billing determinants for all tariff classes are per Cause No. 45285 (2022 plan year billing determinants).

RESIDENTIAL TIME-OF-DAY/OFF PEAK ENERGY STORAGE SERVICE (030, 032, 034, 036)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description	Total	Rate	Revenue	Total	Rate	Revenue	Rate	Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
Billing kWh								
On-peak kWh	9,485,623	$0.19211	$ 1,822,283	9,485,623	$0.17222	$ 1,633,614	$0.17222	$ 1,633,614
Off-peak kWh	16,966,505	$0.05188	$ 880,222	16,966,505	$0.06095	$ 1,034,108	$0.06095	$ 1,034,108
Metered kWh	26,452,128			26,452,128				
Customer Charge	17,477	$16.50	$ 288,371	17,477	$17.00	$ 297,109	$17.00	$ 297,109
Number of Customers	17,553			17,553				
Employee Discount - On-peak	250,561	-$0.01702	$ (4,265)	250,561	-$0.01702	$ (4,265)	-$0.01702	$ (4,265)
Employee Discount - Off-peak	580,884	-$0.00460	$ (2,672)	580,884	-$0.00460	$ (2,672)	-$0.00460	$ (2,672)
Fuel			$ 3,201					
Subtotal			$ 2,987,140			$ 2,957,895		$ 2,957,895
DSM/EE Program Cost Rider - Non-Opt Out	24,841,210	$0.001520	$ 37,759	24,841,210	$0.001242	$ 30,853	$0.001242	$ 30,853
Off-System Sales & PJM Cost Rider	26,452,128	$0.028595	$ 756,399	26,452,128	$0.025731	$ 680,640	$0.025731	$ 680,640
Life Cycle Management Rider	26,452,128	$0.000455	$ 12,036	26,452,128	$0.000013	$ 344	$0.000013	$ 344
Tax Rider	26,452,128	$0.001504	$ 39,784	26,452,128	-$0.003335	$ (88,218)	-$0.003335	$ (88,218)
Solar Power Rider	26,452,128	$0.000197	$ 5,211	26,452,128	$0.000208	$ 5,502	$0.000208	$ 5,502
Environmental Cost Rider	26,452,128	-$0.000742	$ (19,627)	26,452,128	$0.000106	$ 2,804	$0.001786	$ 47,244
Resource Adequacy Rider	26,452,128	-$0.000978	$ (25,870)	26,452,128	$0.006308	$ 166,860	-$0.001179	$ (31,187)
Phase in Rate	26,452,128	-$0.002008	$ (53,116)	26,452,128	$0.000385	$ 10,184	-$0.001751	$ (46,318)
Total			$ 3,739,714			$ 3,766,863		$ 3,556,754

EXPERIMENTAL RESIDENTIAL TIME-OF-DAY SERVICE (021,041)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description	Total	Rate	Revenue	Total	Rate	Revenue	Rate	Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
Billing kWh								
High Cost Hours	73,714	$0.33850	$ 24,952	73,714	$0.37097	$ 27,346	$0.37097	$ 27,346
Low Cost Hours	1,025,756	$0.09651	$ 98,996	1,025,756	$0.09185	$ 94,216	$0.09185	$ 94,216
Metered kWh	1,099,470			1,099,470				
Customer Charge	1,625	$15.00	$ 24,375	1,625	$17.00	$ 27,625	$17.00	$ 27,625
Number of Customers	1,636			1,636				
Employee Discount - High Cost Hours	1,354	-$0.02999	$ (41)	1,354	-$0.02999	$ (41)	-$0.02999	$ (41)
Employee Discount - Low Cost Hours	35,292	-$0.00855	$ (302)	35,292	-$0.00855	$ (302)	-$0.00855	$ (302)
Fuel			$ 133					
Subtotal			$ 148,114			$ 148,844		$ 148,844
DSM/EE Program Cost Rider - Non-Opt Out	1,201,994	$0.001520	$ 1,827	1,201,994	$0.001242	$ 1,493	$0.001242	$ 1,493
Off-System Sales & PJM Cost Rider	1,099,470	$0.028595	$ 31,439	1,099,470	$0.025731	$ 28,290	$0.025731	$ 28,290
Life Cycle Management Rider	1,099,470	$0.000455	$ 500	1,099,470	$0.000013	$ 14	$0.000013	$ 14
Tax Rider	1,099,470	$0.001504	$ 1,654	1,099,470	-$0.003335	$ (3,667)	-$0.003335	$ (3,667)
Solar Power Rider	1,099,470	$0.000197	$ 217	1,099,470	$0.000208	$ 229	$0.000208	$ 229
Environmental Cost Rider	1,099,470	-$0.000742	$ (816)	1,099,470	$0.000106	$ 117	$0.001786	$ 1,964
Resource Adequacy Rider	1,099,470	-$0.000978	$ (1,075)	1,099,470	$0.006308	$ 6,935	-$0.001179	$ (1,296)
Phase in Rate	1,099,470	-$0.002008	$ (2,208)	1,099,470	$0.000385	$ 423	-$0.001751	$ (1,925)
Total			$ 179,652			$ 182,679		$ 173,946

GENERAL SERVICE SECONDARY (211, 212, 215, 216, 218, 281)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description (1)	Total (2)	Rate (3)	Revenue (4)=(2)x(3)	Total (5)	Rate (6)	Revenue (7)=(5)x(6)	Rate (8)	Revenue (9)=(5)x(8)
Billing kWh								
- First 4,500 kWh	678,360,112	$0.11678	$ 79,218,894	678,360,112	$0.10510	$ 71,295,648	$0.10510	$ 71,295,648
- Over 4,500 kWh	350,149,391	$0.08054	$ 28,201,032	350,149,391	$0.09441	$ 33,057,604	$0.09441	$ 33,057,604
Meter Voltage Adjustment	(66,230)			(66,230)				
Metered kWh	1,028,575,733			1,028,575,733				
Billing kW								
-Over 10kW	2,329,246	$6.241	$ 14,536,824	2,329,246	$3.019	$ 7,031,994	$3.019	$ 7,031,994
Customer Charge	595,822	$19.00	$ 11,320,611	595,822	$25.00	$ 14,895,541	$25.00	$ 14,895,541
Number of Customers	597,736			597,736				
EZ Bill Revenues								
Billing kWh	738,051		$ 115,095	738,051		$ 115,106		$ 115,106
Metered kWh	738,051			738,051				
Number of Customers	473			473				
Number of Bills	470			470				
Fuel			$ 124,539					
Subtotal			$ 133,516,995			$ 126,395,892		$ 126,395,892
DSM/EE Program Cost Rider - Non-Opt Out	1,182,388,402	$0.001970	$ 2,329,305	1,182,388,402	$0.000715	$ 845,408	$0.000715	$ 845,408
DSM/EE Program Cost Rider - Opt Out	6,551,996	$0.000013	$ 85	6,551,996	$0.000012	$ 79	$0.000012	$ 79
Off-System Sales & PJM Cost Rider - Energy (Up to 4,500 kWh)	679,098,163	$0.028568	$ 19,400,476	679,098,163	$0.022241	$ 15,103,822	$0.022241	$ 15,103,822
Off-System Sales & PJM Cost Rider - Energy (Over 4,500 kWh)	350,149,391	$0.028568	$ 10,003,068	350,149,391	-$0.001587	$ (555,687)	-$0.001587	$ (555,687)
Off-System Sales & PJM Cost Rider - Demand	2,329,246	$0.000	$ -	2,329,246	$7.276	$ 16,947,594	$7.276	$ 16,947,594
Life Cycle Management Rider - Energy (Up to 4,500 kWh)	679,098,163	$0.000455	$ 308,990	679,098,163	$0.000012	$ 8,149	$0.000012	$ 8,149
Life Cycle Management Rider - Energy (Over 4,500 kWh)	350,149,391	$0.000455	$ 159,318	350,149,391	$0.000000	$ -	$0.000000	$ -
Life Cycle Management Rider - Demand	2,329,246	$0.000	$ -	2,329,246	$0.004	$ 9,317	$0.004	$ 9,317
Tax Rider - Energy (Up to 4,500 kWh)	679,098,163	$0.001505	$ 1,022,043	679,098,163	-$0.002909	$ (1,975,497)	-$0.002909	$ (1,975,497)
Tax Rider - Energy (Over 4,500 kWh)	350,149,391	$0.001505	$ 526,975	350,149,391	$0.000000	$ -	$0.000000	$ -
Tax Rider - Demand	2,329,246	$0.000	$ -	2,329,246	-$0.888	$ (2,068,370)	-$0.888	$ (2,068,370)
Solar Power Rider - Energy (Up to 4,500 kWh)	679,098,163	$0.000197	$ 133,782	679,098,163	$0.000181	$ 122,917	$0.000181	$ 122,917
Solar Power Rider - Energy (Over 4,500 kWh)	350,149,391	$0.000197	$ 68,979	350,149,391	$0.000000	$ -	$0.000000	$ -
Solar Power Rider - Demand	2,329,246	$0.000	$ -	2,329,246	$0.055	$ 128,109	$0.055	$ 128,109
Environmental Cost Rider - Energy (Up to 4,500 kWh)	679,098,163	-$0.000742	$ (503,891)	679,098,163	$0.000106	$ 71,984	$0.001589	$ 1,079,087
Environmental Cost Rider - Energy (Over 4,500 kWh)	350,149,391	-$0.000742	$ (259,811)	350,149,391	$0.000106	$ 37,116	$0.000245	$ 85,787
Environmental Cost Rider - Demand	2,329,246	$0.000	$ -	2,329,246	$0.000	$ -	$0.410	$ 954,991
Resource Adequacy Rider - Energy (Up to 4,500 kWh)	679,098,163	-$0.000978	$ (664,158)	679,098,163	$0.005502	$ 3,736,398	-$0.001028	$ (698,113)
Resource Adequacy Rider - Energy (Over 4,500 kWh)	350,149,391	-$0.000978	$ (342,446)	350,149,391	$0.000000	$ -	$0.000000	$ -
Resource Adequacy Rider - Demand	2,329,246	$0.000	$ -	2,329,246	$1.680	$ 3,913,133	-$0.314	$ (731,383)
Phase in Rate - Energy (Up to 4,500 kWh)	679,098,163	-$0.001758	$ (1,193,855)	679,098,163	$0.001061	$ 720,523	-$0.001527	$ (1,036,983)
Phase in Rate - Energy (Over 4,500 kWh)	350,149,391	-$0.001758	$ (615,563)	350,149,391	$0.001525	$ 533,978	$0.000000	$ -
Phase in Rate - Demand	2,329,246	$0.000	$ -	2,329,246	-$0.141	$ (328,424)	-$0.466	$ (1,085,429)
Total			$ 163,890,293			$ 163,646,441		$ 153,529,689

GENERAL SERVICE LOAD MANAGEMENT TIME-OF-DAY (223, 225)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description (1)	Total (2)	Rate (3)	Revenue (4)=(2)x(3)	Total (5)	Rate (6)	Revenue (7)=(5)x(6)	Rate (8)	Revenue (9)=(5)x(8)
Billing kWh								
On-Peak	1,232,491	$0.14691	$ 181,065	1,232,491	$0.13150	$ 162,073	$0.13150	$ 162,073
Off-Peak	1,982,402	$0.05224	$ 103,561	1,982,402	$0.06118	$ 121,283	$0.06118	$ 121,283
Metered kWh	3,214,893			3,214,893				
Customer Charge	1,240	$19.00	$ 23,560	1,240	$25.00	$ 31,000	$25.00	$ 31,000
Number of Customers	1,241			1,241				
Fuel			$ 389					
Subtotal			$ 308,575			$ 314,356		$ 314,356
DSM/EE Program Cost Rider - Non-Opt Out	3,725,073	$0.001970	$ 7,338	3,725,073	$0.000715	$ 2,663	$0.000715	$ 2,663
Off-System Sales & PJM Cost Rider	3,214,893	$0.028568	$ 91,843	3,214,893	$0.022241	$ 71,502	$0.022241	$ 71,502
Life Cycle Management Rider	3,214,893	$0.000455	$ 1,463	3,214,893	$0.000012	$ 39	$0.000012	$ 39
Tax Rider	3,214,893	$0.001505	$ 4,838	3,214,893	-$0.002909	$ (9,352)	-$0.002909	$ (9,352)
Solar Power Rider	3,214,893	$0.000197	$ 633	3,214,893	$0.000181	$ 582	$0.000181	$ 582
Environmental Cost Rider	3,214,893	-$0.000742	$ (2,385)	3,214,893	$0.000106	$ 341	$0.001589	$ 5,108
Resource Adequacy Rider	3,214,893	-$0.000978	$ (3,144)	3,214,893	$0.005502	$ 17,688	-$0.001028	$ (3,305)
Phase in Rate	3,214,893	-$0.001758	$ (5,652)	3,214,893	$0.001061	$ 3,411	-$0.001527	$ (4,909)
Total			$ 403,510			$ 401,230		$ 376,685

EXPERIMENTAL GENERAL SERVICE TIME-OF-DAY (221, 282)

Description	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
	Total	Rate	Revenue	Total	Rate	Revenue	Rate	Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
Billing kWh								
High Cost Hours	5,946	$0.30299	$ 1,802	5,946	$0.31954	$ 1,900	$0.31954	$ 1,900
Low Cost Hours	11,009	$0.10214	$ 1,124	11,009	$0.09230	$ 1,016	$0.09230	$ 1,016
Metered kWh	16,955			16,955				
Customer Charge	28	$19.00	$ 532	28	$25.00	$ 700	$25.00	$ 700
Cogen Customer Add'l Charge	12	$3.30	$ 40	12	$1.30	$ 16	$1.30	$ 16
Number of Customers	28			28				
Number of Cogen Customers	12			12				
Fuel			$ 2					
Subtotal			$ 3,500			$ 3,632		$ 3,632
DSM/EE Program Cost Rider - Non-Opt Out	16,955	$0.001970	$ 33	16,955	$0.000715	$ 12	$0.000715	$ 12
Off-System Sales & PJM Cost Rider	16,955	$0.028568	$ 484	16,955	$0.022241	$ 377	$0.022241	$ 377
Life Cycle Management Rider	16,955	$0.000455	$ 8	16,955	$0.000012	$ 0	$0.000012	$ 0
Tax Rider	16,955	$0.001505	$ 26	16,955	-$0.002909	$ (49)	-$0.002909	$ (49)
Solar Power Rider	16,955	$0.000197	$ 3	16,955	$0.000181	$ 3	$0.000181	$ 3
Environmental Cost Rider	16,955	-$0.000742	$ (13)	16,955	$0.000106	$ 2	$0.001589	$ 27
Resource Adequacy Rider	16,955	-$0.000978	$ (17)	16,955	$0.005502	$ 93	-$0.001028	$ (17)
Phase in Rate	16,955	-$0.001758	$ (30)	16,955	$0.001061	$ 18	-$0.001527	$ (26)
Total			$ 3,995			$ 4,088		$ 3,959

GENERAL SERVICE - NON METERED (204, 214)

Description	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description (1)	Total (2)	Rate (3)	Revenue (4)=(2)x(3)	Total (5)	Rate (6)	Revenue (7)=(5)x(6)	Rate (8)	Revenue (9)=(5)x(8)
Billing kWh	550,524	$0.11678	$ 64,290	550,524	$0.10510	$ 57,860	$0.10510	$ 57,860
Metered kWh	550,524			550,524				
Customer Charge	3,091	$8.00	$ 24,728	3,091	$9.80	$ 30,292	$9.80	$ 30,292
Number of Customers	2,807			2,807				
Fuel			$ 67					
Subtotal			$ 89,085			$ 88,152		$ 88,152
Off-System Sales & PJM Cost Rider	550,524	$0.028568	$ 15,727	550,524	$0.022241	$ 12,244	$0.022241	$ 12,244
Life Cycle Management Rider	550,524	$0.000455	$ 250	550,524	$0.000012	$ 7	$0.000012	$ 7
Tax Rider	550,524	$0.001505	$ 829	550,524	-$0.002909	$ (1,601)	-$0.002909	$ (1,601)
Solar Power Rider	550,524	$0.000197	$ 108	550,524	$0.000181	$ 100	$0.000181	$ 100
Environmental Cost Rider	550,524	-$0.000742	$ (408)	550,524	$0.000106	$ 58	$0.001589	$ 875
Resource Adequacy Rider	550,524	-$0.000978	$ (538)	550,524	$0.005502	$ 3,029	-$0.001028	$ (566)
Phase in Rate	550,524	-$0.001758	$ (968)	550,524	$0.001061	$ 584	-$0.001527	$ (841)
Total			$ 104,085			$ 102,572		$ 98,369

GENERAL SERVICE TIME-OF-DAY - SECONDARY (229)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description	Total	Rate	Revenue	Total	Rate	Revenue	Rate	Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
Billing kWh								
On-peak kWh	18,699,098	$0.14691	$ 2,747,084	18,699,098	$0.13150	$ 2,458,931	$0.13150	$ 2,458,931
Off-peak kWh	25,750,263	$0.05224	$ 1,345,194	25,750,263	$0.06118	$ 1,575,401	$0.06118	$ 1,575,401
Meter Voltage Adjustment	(2,955)			(2,955)				
Metered kWh	44,452,316			44,452,316				
Customer Charge	18,975	$19.00	$ 360,525	18,975	$25.00	$ 474,375	$25.00	$ 474,375
Number of Customers	19,036			19,036				
Fuel			$ 5,378					
Subtotal			$ 4,458,182			$ 4,508,707		$ 4,508,707
DSM/EE Program Cost Rider - Non-Opt Out	51,380,311	$0.001970	$ 101,219	51,380,311	$0.000715	$ 36,737	$0.000715	$ 36,737
Off-System Sales & PJM Cost Rider	44,449,361	$0.028568	$ 1,269,829	44,449,361	$0.022241	$ 988,598	$0.022241	$ 988,598
Life Cycle Management Rider	44,449,361	$0.000455	$ 20,224	44,449,361	$0.000012	$ 533	$0.000012	$ 533
Tax Rider	44,449,361	$0.001505	$ 66,896	44,449,361	-$0.002909	$ (129,303)	-$0.002909	$ (129,303)
Solar Power Rider	44,449,361	$0.000197	$ 8,757	44,449,361	$0.000181	$ 8,045	$0.000181	$ 8,045
Environmental Cost Rider	44,449,361	-$0.000742	$ (32,981)	44,449,361	$0.000106	$ 4,712	$0.001589	$ 70,630
Resource Adequacy Rider	44,449,361	-$0.000978	$ (43,471)	44,449,361	$0.005502	$ 244,560	-$0.001028	$ (45,694)
Phase in Rate	44,449,361	-$0.001758	$ (78,142)	44,449,361	$0.001061	$ 47,161	-$0.001527	$ (67,874)
Total			$ 5,770,513			$ 5,709,751		$ 5,370,380

GENERAL SERVICE TIME-OF-DAY - Primary (227)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description	Total	Rate	Revenue	Total	Rate	Revenue	Rate	Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
Billing kWh								
On-peak kWh	553	$0.11943	$ 66	553	$0.10061	$ 56	$0.10061	$ 56
Off-peak kWh	0	$0.05181	$ -	0	$0.06062	$ -	$0.06062	$ -
Metered kWh	553			553				
Customer Charge	1	$141.00	$ 141	1	$180.00	$ 180	$180.00	$ 180
Number of Customers	1			1				
Fuel			$ 0					
Subtotal			$ 207			$ 236		$ 236
DSM/EE Program Cost Rider - Non-Opt Out	553	$0.001970	$ 1	553	$0.000715	$ 0	$0.000715	$ 0
Off-System Sales & PJM Cost Rider	553	$0.028568	$ 16	553	$0.022241	$ 12	$0.022241	$ 12
Life Cycle Management Rider	553	$0.000455	$ 0	553	$0.000012	$ 0	$0.000012	$ 0
Tax Rider	553	$0.001505	$ 1	553	-$0.002909	$ (2)	-$0.002909	$ (2)
Solar Power Rider	553	$0.000197	$ 0	553	$0.000181	$ 0	$0.000181	$ 0
Environmental Cost Rider	553	-$0.000742	$ (0)	553	$0.000106	$ 0	$0.001589	$ 1
Resource Adequacy Rider	553	-$0.000978	$ (1)	553	$0.005502	$ 3	-$0.001028	$ (1)
Phase in Rate	553	-$0.001758	$ (1)	553	$0.001061	$ 1	-$0.001527	$ (1)
Total			$ 223			$ 251		$ 246

GENERAL SERVICE - PRIMARY (217)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description (1)	Total (2)	Rate (3)	Revenue (4)=(2)x(3)	Total (5)	Rate (6)	Revenue (7)=(5)x(6)	Rate (8)	Revenue (9)=(5)x(8)
Billing kWh	27,866,219			27,866,219				
- First 4,500 kWh	2,141,530	$0.11341	$ 242,871	2,141,530	$0.09714	$ 208,028	$0.09714	$ 208,028
- Over 4,500 kWh	25,724,689	$0.07817	$ 2,010,899	25,724,689	$0.08674	$ 2,231,360	$0.08674	$ 2,231,360
Meter Voltage Adjustment	324			324				
Metered kWh	27,865,895			27,865,895				
Billing kW								
-Over 10kW	156,430	$4.229	$ 661,542	156,430	$1.892	$ 295,966	$1.892	$ 295,966
Customer Charge	563	$135.00	$ 76,005	563	$180.00	$ 101,340	$180.00	$ 101,340
Number of Customers	564			564				
Fuel			$ 3,372					
Subtotal			$ 2,994,689			$ 2,836,693		$ 2,836,693
DSM/EE Program Cost Rider - Non-Opt Out	26,242,438	$0.001970	$ 51,698	26,242,438	$0.000715	$ 18,763	$0.000715	$ 18,763
DSM/EE Program Cost Rider - Opt Out	5,998,707	$0.000013	$ 78	5,998,707	$0.000012	$ 72	$0.000012	$ 72
Off-System Sales & PJM Cost Rider - Energy (Up to 4,500 kWh)	2,141,530	$0.028568	$ 61,179	2,141,530	$0.022241	$ 47,630	$0.022241	$ 47,630
Off-System Sales & PJM Cost Rider - Energy (Over 4,500 kWh)	25,724,689	$0.028568	$ 734,903	25,724,689	-$0.001587	$ (40,825)	-$0.001587	$ (40,825)
Off-System Sales & PJM Cost Rider - Demand	156,430	$0.000	$ -	156,430	$7.276	$ 1,138,185	$7.276	$ 1,138,185
Life Cycle Management Rider - Energy (Up to 4,500 kWh)	2,141,530	$0.000455	$ 974	2,141,530	$0.000012	$ 26	$0.000012	$ 26
Life Cycle Management Rider - Energy (Over 4,500 kWh)	25,724,689	$0.000455	$ 11,705	25,724,689	$0.000000	$ -	$0.000000	$ -
Life Cycle Management Rider - Demand	156,430	$0.000	$ -	156,430	$0.004	$ 626	$0.004	$ 626
Tax Rider - Energy (Up to 4,500 kWh)	2,141,530	$0.001505	$ 3,223	2,141,530	-$0.002909	$ (6,230)	-$0.002909	$ (6,230)
Tax Rider - Energy (Over 4,500 kWh)	25,724,689	$0.001505	$ 38,716	25,724,689	$0.000000	$ -	$0.000000	$ -
Tax Rider - Demand	156,430	$0.000	$ -	156,430	-$0.888	$ (138,910)	-$0.888	$ (138,910)
Solar Power Rider - Energy (Up to 4,500 kWh)	2,141,530	$0.000197	$ 422	2,141,530	$0.000181	$ 388	$0.000181	$ 388
Solar Power Rider - Energy (Over 4,500 kWh)	25,724,689	$0.000197	$ 5,068	25,724,689	$0.000000	$ -	$0.000000	$ -
Solar Power Rider - Demand	156,430	$0.000	$ -	156,430	$0.055	$ 8,604	$0.055	$ 8,604
Environmental Cost Rider - Energy (Up to 4,500 kWh)	2,141,530	-$0.000742	$ (1,589)	2,141,530	$0.000106	$ 227	$0.001589	$ 3,403
Environmental Cost Rider - Energy (Over 4,500 kWh)	25,724,689	-$0.000742	$ (19,088)	25,724,689	$0.000106	$ 2,727	$0.000245	$ 6,303
Environmental Cost Rider - Demand	156,430	$0.000	$ -	156,430	$0.000	$ -	$0.410	$ 64,136
Resource Adequacy Rider - Energy (Up to 4,500 kWh)	2,141,530	-$0.000978	$ (2,094)	2,141,530	$0.005502	$ 11,783	-$0.001028	$ (2,201)
Resource Adequacy Rider - Energy (Over 4,500 kWh)	25,724,689	-$0.000978	$ (25,159)	25,724,689	$0.000000	$ -	$0.000000	$ -
Resource Adequacy Rider - Demand	156,430	$0.000	$ -	156,430	$1.680	$ 262,802	-$0.314	$ (49,119)
Phase in Rate - Energy (Up to 4,500 kWh)	2,141,530	-$0.001758	$ (3,765)	2,141,530	$0.001061	$ 2,272	-$0.001527	$ (3,270)
Phase in Rate - Energy (Over 4,500 kWh)	25,724,689	-$0.001758	$ (45,224)	25,724,689	$0.001525	$ 39,230	$0.000000	$ -
Phase in Rate - Demand	156,430	$0.000	$ -	156,430	-$0.141	$ (22,057)	-$0.466	$ (72,896)
Total			$ 3,805,736			$ 4,162,006		$ 3,811,376

GENERAL SERVICE - SUBTRANSMISSION (236)

Description	Current Total	Current Rate	Current Revenue	Proposed (May-1, 2022 - Dec-31, 2022) Total	Proposed (May-1, 2022 - Dec-31, 2022) Rate	Proposed (May-1, 2022 - Dec-31, 2022) Revenue	Proposed (As of Jan-1, 2023) Rate	Proposed (As of Jan-1, 2023) Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
Billing kWh	6,738,742			6,738,742				
- First 4,500 kWh	118,556	$0.11193	$ 13,270	118,556	$0.08852	$ 10,495	$0.08852	$ 10,495
- Over 4,500 kWh	6,620,186	$0.07719	$ 511,012	6,620,186	$0.07827	$ 518,162	$0.07827	$ 518,162
Meter Voltage Adjustment	25			25				
Metered kWh	6,738,717			6,738,717				
Billing kW								
-Over 10 kW	17,073	$1.220	$ 20,829	17,073	$0.000	$ -	$0.000	$ -
Customer Charge	48	$135.00	$ 6,480	48	$180.00	$ 8,640	$180.00	$ 8,640
Number of Customers	48			48				
Fuel			$ 815					
Subtotal			$ 552,407			$ 537,297		$ 537,297
DSM/EE Program Cost Rider - Non-Opt Out	7,835,497	$0.001970	$ 15,436	7,835,497	$0.000715	$ 5,602	$0.000715	$ 5,602
Off-System Sales & PJM Cost Rider - Energy (Up to 4,500 kWh)	118,556	$0.028568	$ 3,387	118,556	$0.022241	$ 2,637	$0.022241	$ 2,637
Off-System Sales & PJM Cost Rider - Energy (Over 4,500 kWh)	6,620,186	$0.028568	$ 189,125	6,620,186	-$0.001587	$ (10,506)	-$0.001587	$ (10,506)
Off-System Sales & PJM Cost Rider - Demand	17,073	$0.000	$ -	17,073	$7.276	$ 124,223	$7.276	$ 124,223
Life Cycle Management Rider - Energy (Up to 4,500 kWh)	118,556	$0.000455	$ 54	118,556	$0.000012	$ 1	$0.000012	$ 1
Life Cycle Management Rider - Energy (Over 4,500 kWh)	6,620,186	$0.000455	$ 3,012	6,620,186	$0.000000	$ -	$0.000000	$ -
Life Cycle Management Rider - Demand	17,073	$0.000	$ -	17,073	$0.004	$ 68	$0.004	$ 68
Tax Rider - Energy (Up to 4,500 kWh)	118,556	$0.001505	$ 178	118,556	-$0.002909	$ (345)	-$0.002909	$ (345)
Tax Rider - Energy (Over 4,500 kWh)	6,620,186	$0.001505	$ 9,963	6,620,186	$0.000000	$ -	$0.000000	$ -
Tax Rider - Demand	17,073	$0.000	$ -	17,073	-$0.888	$ (15,161)	-$0.888	$ (15,161)
Solar Power Rider - Energy (Up to 4,500 kWh)	118,556	$0.000197	$ 23	118,556	$0.000181	$ 21	$0.000181	$ 21
Solar Power Rider - Energy (Over 4,500 kWh)	6,620,186	$0.000197	$ 1,304	6,620,186	$0.000000	$ -	$0.000000	$ -
Solar Power Rider - Demand	17,073	$0.000	$ -	17,073	$0.055	$ 939	$0.055	$ 939
Environmental Cost Rider - Energy (Up to 4,500 kWh)	118,556	-$0.000742	$ (88)	118,556	$0.000106	$ 13	$0.001589	$ 188
Environmental Cost Rider - Energy (Over 4,500 kWh)	6,620,186	-$0.000742	$ (4,912)	6,620,186	$0.000106	$ 702	$0.000245	$ 1,622
Environmental Cost Rider - Demand	17,073	$0.000	$ -	17,073	$0.000	$ -	$0.410	$ 7,000
Resource Adequacy Rider - Energy (Up to 4,500 kWh)	118,556	-$0.000978	$ (116)	118,556	$0.005502	$ 652	-$0.001028	$ (122)
Resource Adequacy Rider - Energy (Over 4,500 kWh)	6,620,186	-$0.000978	$ (6,475)	6,620,186	$0.000000	$ -	$0.000000	$ -
Resource Adequacy Rider - Demand	17,073	$0.000	$ -	17,073	$1.680	$ 28,683	-$0.314	$ (5,361)
Phase in Rate - Energy (Up to 4,500 kWh)	118,556	-$0.001758	$ (208)	118,556	$0.001061	$ 126	-$0.001527	$ (181)
Phase in Rate - Energy (Over 4,500 kWh)	6,620,186	-$0.001758	$ (11,638)	6,620,186	$0.001525	$ 10,096	$0.000000	$ -
Phase in Rate - Demand	17,073	$0.000	$ -	17,073	-$0.141	$ (2,407)	-$0.466	$ (7,956)
Total			$ 751,453			$ 682,641		$ 639,968

INDIANA MICHIGAN POWER COMPANY - INDIANA
PROFORMA
TEST YEAR ENDED DECEMBER 31, 2022

GENERAL SERVICE - TRANSMISSION (239)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description	Total	Rate	Revenue	Total	Rate	Revenue	Rate	Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
	$16,850.22							
Billing kWh	387,555			387,555				
- First 4,500 kWh	84,160	$0.11075	$ 9,321	84,160	$0.08789	$ 7,397	$0.08789	$ 7,397
- Over 4,500 kWh	303,395	$0.07638	$ 23,173	303,395	$0.07775	$ 23,589	$0.07775	$ 23,589
Meter Voltage Adjustment	0			0				
Metered kWh	387,555			387,555				
Billing kW								
-Over 10 kW	4,253	$1.205	$ 5,125	4,253	$0.000	$ -	$0.000	$ -
Customer Charge	23	$135.00	$ 3,105	23	$180.00	$ 4,140	$180.00	$ 4,140
Number of Customers	24			24				
Fuel			$ 47					
Subtotal			$ 40,771			$ 35,126		$ 35,126
DSM/EE Program Cost Rider - Non-Opt Out	385,352	$0.001970	$ 759	385,352	$0.000715	$ 276	$0.000715	$ 276
Off-System Sales & PJM Cost Rider - Energy (Up to 4,500 kWh)	84,160	$0.028568	$ 2,404	84,160	$0.022241	$ 1,872	$0.022241	$ 1,872
Off-System Sales & PJM Cost Rider - Energy (Over 4,500 kWh)	303,395	$0.028568	$ 8,667	303,395	-$0.001587	$ (481)	-$0.001587	$ (481)
Off-System Sales & PJM Cost Rider - Demand	4,253	$0.000	$ -	4,253	$7.276	$ 30,945	$7.276	$ 30,945
Life Cycle Management Rider - Energy (Up to 4,500 kWh)	84,160	$0.000455	$ 38	84,160	$0.000012	$ 1	$0.000012	$ 1
Life Cycle Management Rider - Energy (Over 4,500 kWh)	303,395	$0.000455	$ 138	303,395	$0.000000	$ -	$0.000000	$ -
Life Cycle Management Rider - Demand	4,253	$0.000	$ -	4,253	$0.004	$ 17	$0.004	$ 17
Tax Rider - Energy (Up to 4,500 kWh)	84,160	$0.001505	$ 127	84,160	-$0.002909	$ (245)	-$0.002909	$ (245)
Tax Rider - Energy (Over 4,500 kWh)	303,395	$0.001505	$ 457	303,395	$0.000000	$ -	$0.000000	$ -
Tax Rider - Demand	4,253	$0.000	$ -	4,253	-$0.888	$ (3,777)	-$0.888	$ (3,777)
Solar Power Rider - Energy (Up to 4,500 kWh)	84,160	$0.000197	$ 17	84,160	$0.000181	$ 15	$0.000181	$ 15
Solar Power Rider - Energy (Over 4,500 kWh)	303,395	$0.000197	$ 60	303,395	$0.000000	$ -	$0.000000	$ -
Solar Power Rider - Demand	4,253	$0.000	$ -	4,253	$0.055	$ 234	$0.055	$ 234
Environmental Cost Rider - Energy (Up to 4,500 kWh)	84,160	-$0.000742	$ (62)	84,160	$0.000106	$ 9	$0.001589	$ 134
Environmental Cost Rider - Energy (Over 4,500 kWh)	303,395	-$0.000742	$ (225)	303,395	$0.000106	$ 32	$0.000245	$ 74
Environmental Cost Rider - Demand	4,253	$0.000	$ -	4,253	$0.000	$ -	$0.410	$ 1,744
Resource Adequacy Rider - Energy (Up to 4,500 kWh)	84,160	-$0.000978	$ (82)	84,160	$0.005502	$ 463	-$0.001028	$ (87)
Resource Adequacy Rider - Energy (Over 4,500 kWh)	303,395	-$0.000978	$ (297)	303,395	$0.000000	$ -	$0.000000	$ -
Resource Adequacy Rider - Demand	4,253	$0.000	$ -	4,253	$1.680	$ 7,145	-$0.314	$ (1,335)
Phase in Rate - Energy (Up to 4,500 kWh)	84,160	-$0.001758	$ (148)	84,160	$0.001061	$ 89	-$0.001527	$ (129)
Phase in Rate - Energy (Over 4,500 kWh)	303,395	-$0.001758	$ (533)	303,395	$0.001525	$ 463	$0.000000	$ -
Phase in Rate - Demand	4,253	$0.000	$ -	4,253	-$0.141	$ (600)	-$0.466	$ (1,982)
Total			$ 52,090			$ 71,584		$ 62,402

LARGE GENERAL SERVICE - SECONDARY (240, 242)

Description	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
	Total	Rate	Revenue	Total	Rate	Revenue	Rate	Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
Billing kWh	2,487,504,788							
- First 300 kWh per kVA	2,099,684,157	$0.07523	$ 157,959,239					
- Over 300 kWh per kVA	387,820,631	$0.03888	$ 15,078,466					
Billing kWh				2,536,755,288				
- First 300 kWh per kW				1,950,442,699	$0.07523	$ 146,731,804	$0.07523	$ 146,731,804
- Over 300 kWh per kW				586,312,589	$0.03184	$ 18,668,193	$0.03184	$ 18,668,193
Meter Voltage Adjustment	(169,947)			(169,947)				
Metered kWh	2,536,925,235			2,536,925,235				
Billing kVA	8,428,833	$6.241	$ 52,604,347	646,757	$7.548	$ 4,881,722	$7.548	$ 4,881,722
Billing kW								
- All kW				7,183,909	$7.548	$ 54,224,145	$7.548	$ 54,224,145
Customer Charge	57,629	$35.30	$ 2,034,304	57,629	$25.00	$ 1,440,725	$25.00	$ 1,440,725
D.R.S. 2 Customer Charge	24	$10.00	$ 240	24	$10.00	$ 240	$10.00	$ 240
Number of Customers	57,667			57,667				
Economic Development Rider			$ (148,415)			$ (148,415)		$ (148,415)
Fuel			$ 300,988					
Subtotal			$ 227,829,168			$ 225,798,414		$ 225,798,414
DSM/EE Program Cost Rider - Non-Opt Out	2,538,648,399	$0.001706	$ 4,330,934	2,588,911,499	$0.000715	$ 1,851,072	$0.000715	$ 1,851,072
DSM/EE Program Cost Rider - Opt Out	8,216,968	$0.000011	$ 90	8,379,657	$0.000012	$ 101	$0.000012	$ 101
Off-System Sales & PJM Cost Rider - Energy (Up to 4,500 kWh)	2,487,504,788	$0.000512	$ 1,273,602	0	$0.022241	$ -	$0.022241	$ -
Off-System Sales & PJM Cost Rider - Energy (Over 4,500 kWh)		$0.000000		2,536,755,288	-$0.001587	$ (4,025,831)	-$0.001587	$ (4,025,831)
Off-System Sales & PJM Cost Rider - Demand	8,428,833	$6.319	$ 53,261,796	7,183,909	$7.276	$ 52,270,122	$7.276	$ 52,270,122
Life Cycle Management Rider - Energy (Up to 4,500 kWh)	2,487,504,788	$0.000000	$ -	0	$0.000012	$ -	$0.000012	$ -
Life Cycle Management Rider - Energy (Over 4,500 kWh)		$0.000000		2,536,755,288	$0.000000	$ -	$0.000000	$ -
Life Cycle Management Rider - Demand	8,428,833	$0.103	$ 868,170	7,183,909	$0.004	$ 28,736	$0.004	$ 28,736
Tax Rider - Energy (Up to 4,500 kWh)	2,487,504,788	$0.000000	$ -	0	-$0.002909	$ -	-$0.002909	$ -
Tax Rider - Energy (Over 4,500 kWh)		$0.000000		2,536,755,288	$0.000000	$ -	$0.000000	$ -
Tax Rider - Demand	8,428,833	$0.338	$ 2,848,946	7,183,909	-$0.888	$ (6,379,311)	-$0.888	$ (6,379,311)
Solar Power Rider - Energy (Up to 4,500 kWh)	2,487,504,788	$0.000000	$ -	0	$0.000181	$ -	$0.000181	$ -
Solar Power Rider - Energy (Over 4,500 kWh)		$0.000000		2,536,755,288	$0.000000	$ -	$0.000000	$ -
Solar Power Rider - Demand	8,428,833	$0.044	$ 370,869	7,183,909	$0.055	$ 395,115	$0.055	$ 395,115
Environmental Cost Rider - Energy (Up to 4,500 kWh)	2,487,504,788	-$0.000755	$ (1,878,066)	0	$0.000106	$ -	$0.000245	$ -
Environmental Cost Rider - Energy (Over 4,500 kWh)		$0.000000		2,536,755,288	$0.000106	$ 268,896	$0.000245	$ 621,505
Environmental Cost Rider - Demand	8,428,833	$0.003	$ 25,286	7,183,909	$0.000	$ -	$0.410	$ 2,945,403
Resource Adequacy Rider - Energy (Up to 4,500 kWh)	2,487,504,788	$0.000000	$ -	0	$0.005502	$ -	$0.000000	$ -
Resource Adequacy Rider - Energy (Over 4,500 kWh)		$0.000000		2,536,755,288	$0.000000	$ -	$0.000000	$ -
Resource Adequacy Rider - Demand	8,428,833	-$0.220	$ (1,854,343)	7,183,909	$1.680	$ 12,068,967	-$0.314	$ (2,255,747)
Phase in Rate - Energy (Up to 4,500 kWh)	2,487,504,788	-$0.000005	$ (12,438)	0	$0.001061	$ -	-$0.001527	$ -
Phase in Rate - Energy (Over 4,500 kWh)		$0.000000		2,536,755,288	$0.001525	$ 3,868,552	$0.000000	$ -
Phase in Rate - Demand	8,428,833	-$0.379	$ (3,194,528)	7,183,909	-$0.141	$ (1,012,931)	-$0.466	$ (3,347,702)
Total			$ 283,869,487			$ 285,131,900		$ 267,901,875

LARGE GENERAL SERVICE LOAD MANAGEMENT TIME-OF-DAY (251)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description (1)	Total (2)	Rate (3)	Revenue (4)=(2)x(3)	Total (5)	Rate (6)	Revenue (7)=(5)x(6)	Rate (8)	Revenue (9)=(5)x(8)
Billing kWh								
On-peak kWh	3,396,690	$0.14691	$ 499,008	3,396,690	$0.13150	$ 446,665	$0.13150	$ 446,665
Off-peak kWh	5,436,775	$0.05224	$ 284,017	5,436,775	$0.06118	$ 332,622	$0.06118	$ 332,622
Metered kWh	8,833,465			8,833,465				
Customer Charge	567	$35.30	$ 20,015	567	$25.00	$ 14,175	$25.00	$ 14,175
Number of Customers	568			568				
Fuel			$ 1,069					
Subtotal			$ 804,109			$ 793,462		$ 793,462
DSM/EE Program Cost Rider - Non-Opt Out	9,982,323	$0.001706	$ 17,030	9,982,323	$0.000715	$ 7,137	$0.000715	$ 7,137
Off-System Sales & PJM Cost Rider	8,833,465	$0.021717	$ 191,836	8,833,465	$0.022241	$ 196,465	$0.022241	$ 196,465
Life Cycle Management Rider	8,833,465	$0.000345	$ 3,048	8,833,465	$0.000012	$ 106	$0.000012	$ 106
Tax Rider	8,833,465	$0.001136	$ 10,035	8,833,465	-$0.002909	$ (25,697)	-$0.002909	$ (25,697)
Solar Power Rider	8,833,465	$0.000148	$ 1,307	8,833,465	$0.000181	$ 1,599	$0.000181	$ 1,599
Environmental Cost Rider	8,833,465	-$0.000747	$ (6,599)	8,833,465	$0.000106	$ 936	$0.001589	$ 14,036
Resource Adequacy Rider	8,833,465	-$0.000739	$ (6,528)	8,833,465	$0.005502	$ 48,602	-$0.001028	$ (9,081)
Phase in Rate	8,833,465	-$0.001227	$ (10,839)	8,833,465	$0.001061	$ 9,372	-$0.001527	$ (13,489)
Total			$ 1,003,400			$ 1,031,983		$ 964,539

LARGE GENERAL SERVICE TIME-OF-DAY SECONDARY (253)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description (1)	Total (2)	Rate (3)	Revenue (4)=(2)x(3)	Total (5)	Rate (6)	Revenue (7)=(5)x(6)	Rate (8)	Revenue (9)=(5)x(8)
Billing kWh								
On-peak kWh	29,674,643	$0.10460	$ 3,103,968	29,674,643	$0.09580	$ 2,842,831	$0.09580	$ 2,842,831
Off-peak kWh	36,828,959	$0.05224	$ 1,923,945	36,828,959	$0.05118	$ 1,884,906	$0.05118	$ 1,884,906
Demand Charge	168,633	$5.192	$ 875,543	168,633	$7.548	$ 1,272,842	$7.548	$ 1,272,842
Metered kWh	66,503,602			66,503,602				
Customer Charge	6,007	$35.30	$ 212,047	6,007	$25.00	$ 150,175	$25.00	$ 150,175
Number of Customers	6,031			6,031				
Fuel			$ 8,047					
Subtotal			$ 6,123,549			$ 6,150,754		$ 6,150,754
DSM/EE Program Cost Rider - Non-Opt Out	68,120,307	$0.001706	$ 116,213	68,120,307	$0.000715	$ 48,706	$0.000715	$ 48,706
Off-System Sales & PJM Cost Rider - Energy (Up to 4,500 kWh)	66,503,602	$0.000512	$ 34,050		$0.022241	$ -	$0.022241	$ -
Off-System Sales & PJM Cost Rider - Energy (Over 4,500 kWh)		$0.000000		66,503,602	-$0.002	$ (105,541)	-$0.002	$ (105,541)
Off-System Sales & PJM Cost Rider - Demand	168,633	$6.319	$ 1,065,592	168,633	$7.276	$ 1,226,974	$7.276000	$ 1,226,974
Life Cycle Management Rider - Energy (Up to 4,500 kWh)	66,503,602	$0.000000	$ -		$0.000012	$ -	$0.000012	$ -
Life Cycle Management Rider - Energy (Over 4,500 kWh)		$0.000000		66,503,602	$0.000	$ -	$0.000	$ -
Life Cycle Management Rider - Demand	168,633	$0.103000	$ 17,369	168,633	$0.004000	$ 675	$0.004000	$ 675
Tax Rider - Energy (Up to 4,500 kWh)	66,503,602	$0.000000	$ -		-$0.002909	$ -	-$0.002909	$ -
Tax Rider - Energy (Over 4,500 kWh)		$0.000000		66,503,602	$0.000000	$ -	$0.000000	$ -
Tax Rider - Demand	168,633	$0.338000	$ 56,998	168,633	-$0.888	$ (149,746)	-$0.888	$ (149,746)
Solar Power Rider - Energy (Up to 4,500 kWh)	66,503,602	$0.000000	$ -		$0.000181	$ -	$0.000181	$ -
Solar Power Rider - Energy (Over 4,500 kWh)		$0.000000		66,503,602	$0.000000	$ -	$0.000000	$ -
Solar Power Rider - Demand	168,633	$0.044000	$ 7,420	168,633	$0.055	$ 9,275	$0.055	$ 9,275
Environmental Cost Rider - Energy (Up to 4,500 kWh)	66,503,602	-$0.000755	$ (50,210)		$0.000106	$ -	$0.000245	$ -
Environmental Cost Rider - Energy (Over 4,500 kWh)		$0.000000		66,503,602	$0.000106	$ 7,049	$0.000245	$ 16,293
Environmental Cost Rider - Demand	168,633	$0.003000	$ 506	168,633	$0.000	$ -	$0.410	$ 69,140
Resource Adequacy Rider - Energy (Up to 4,500 kWh)	66,503,602	$0.000000	$ -		$0.005502	$ -	$0.000000	$ -
Resource Adequacy Rider - Energy (Over 4,500 kWh)		$0.000000		66,503,602	$0.000000	$ -	$0.000000	$ -
Resource Adequacy Rider - Demand	168,633	-$0.220000	$ (37,099)	168,633	$1.680	$ 283,303	-$0.314	$ (52,951)
Phase in Rate - Energy (Up to 4,500 kWh)	66,503,602	-$0.000005	$ (333)		$0.001061	$ -	-$0.001527	$ -
Phase in Rate - Energy (Over 4,500 kWh)		$0.000000		66,503,602	$0.001525	$ 101,418	$0.000000	$ -
Phase in Rate - Demand	168,633	-$0.379000	$ (63,912)	168,633	-$0.141	$ (23,777)	-$0.466	$ (78,583)
Total			$ 7,270,143			$ 7,549,089		$ 7,134,995

INDIANA MICHIGAN POWER COMPANY - INDIANA
PROFORMA
TEST YEAR ENDED DECEMBER 31, 2022

LARGE GENERAL SERVICE TIME-OF-DAY PRIMARY (255)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description	Total	Rate	Revenue	Total	Rate	Revenue	Rate	Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
Billing kWh								
On-peak kWh	283,422	$0.09889	$ 28,028	283,422	$0.08438	$ 23,915	$0.08438	$ 23,915
Off-peak kWh	181,983	$0.05181	$ 9,429	181,983	$0.05062	$ 9,212	$0.05062	$ 9,212
Demand Charge	1,218	$3.124	$ 3,805	1,218	$4.731	$ 5,762	$4.731	$ 5,762
Metered kWh	465,405			465,405				
Customer Charge	12	$141.00	$ 1,692	12	$180.00	$ 2,160	$180.00	$ 2,160
Number of Customers	12			12				
Fuel			$ 56					
Subtotal			$ 43,009			$ 41,049		$ 41,049
DSM/EE Program Cost Rider - Non-Opt Out	556,084	$0.001706	$ 949	556,084	$0.000715	$ 398	$0.000715	$ 398
Off-System Sales & PJM Cost Rider - Energy (Up to 4,500 kWh)	465,405	$0.000512	$ 238	0	$0.022241	$ -	$0.022241	$ -
Off-System Sales & PJM Cost Rider - Energy (Over 4,500 kWh)		$0.000000		465,405	-$0.001587	$ (739)	-$0.001587	$ (739)
Off-System Sales & PJM Cost Rider - Demand	1,218	$6.319	$ 7,697	1,218	$7.276	$ 8,862	$7.276	$ 8,862
Life Cycle Management Rider - Energy (Up to 4,500 kWh)	465,405	$0.000000	$ -	0	$0.000012	$ -	$0.000012	$ -
Life Cycle Management Rider - Energy (Over 4,500 kWh)		$0.000000		465,405	$0.000000	$ -	$0.000000	$ -
Life Cycle Management Rider - Demand	1,218	$0.103	$ 125	1,218	$0.004	$ 5	$0.004	$ 5
Tax Rider - Energy (Up to 4,500 kWh)	465,405	$0.000000		0	-$0.002909	$ -	-$0.002909	$ -
Tax Rider - Energy (Over 4,500 kWh)		$0.000000		465,405	$0.000000	$ -	$0.000000	$ -
Tax Rider - Demand	1,218	$0.338	$ 412	1,218	-$0.888	$ (1,082)	-$0.888	$ (1,082)
Solar Power Rider - Energy (Up to 4,500 kWh)	465,405	$0.000000	$ -	0	$0.000181	$ -	$0.000181	$ -
Solar Power Rider - Energy (Over 4,500 kWh)		$0.000000		465,405	$0.000000	$ -	$0.000000	$ -
Solar Power Rider - Demand	1,218	$0.044	$ 54	1,218	$0.055	$ 67	$0.055	$ 67
Environmental Cost Rider - Energy (Up to 4,500 kWh)	465,405	-$0.000755	$ (351)	0	$0.000106	$ -	$0.000245	$ -
Environmental Cost Rider - Energy (Over 4,500 kWh)		$0.000000		465,405	$0.000106	$ 49	$0.000245	$ 114
Environmental Cost Rider - Demand	1,218	$0.003	$ 4	1,218	$0.000	$ -	$0.410	$ 499
Resource Adequacy Rider - Energy (Up to 4,500 kWh)	465,405	$0.000000	$ -	0	$0.005502	$ -	$0.000000	$ -
Resource Adequacy Rider - Energy (Over 4,500 kWh)		$0.000000		465,405	$0.000000	$ -	$0.000000	$ -
Resource Adequacy Rider - Demand	1,218	-$0.220	$ (268)	1,218	$1.680	$ 2,046	-$0.314	$ (382)
Phase in Rate - Energy (Up to 4,500 kWh)	465,405	-$0.000005	$ (2)	0	$0.001061	$ -	-$0.001527	$ -
Phase in Rate - Energy (Over 4,500 kWh)		$0.000000		465,405	$0.001525	$ 710	$0.000000	$ -
Phase in Rate - Demand	1,218	-$0.379	$ (462)	1,218	-$0.141	$ (172)	-$0.466	$ (568)
Total			$ 51,404			$ 51,195		$ 48,224

LARGE GENERAL SERVICE - PRIMARY (244, 246)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description (1)	Total (2)	Rate (3)	Revenue (4)=(2)x(3)	Total (5)	Rate (6)	Revenue (7)=(5)x(6)	Rate (8)	Revenue (9)=(5)x(8)
Billing kWh	157,514,748							
- First 300 kWh per kVA	131,535,613	$0.07310	$ 9,615,253					
- Over 300 kWh per kVA	25,979,135	$0.03777	$ 981,232					
Billing kWh				159,501,965				
- First 300 kWh per kW				122,806,552	$0.07270	$ 8,928,036	$0.07270	$ 8,928,036
- Over 300 kWh per kW				36,695,413	$0.03030	$ 1,111,871	$0.03030	$ 1,111,871
Meter Voltage Adjustment	4,965			4,965				
Metered kWh	159,497,000			159,497,000				
Billing kVa	502,962	$4.229	$ 2,127,026	49,770	$4.730	$ 235,412	$4.730	$ 235,412
Billing kW								
-All kW				445,430	$4.730	$ 2,106,884	$4.730	$ 2,106,884
Customer Charge	1,079	$159.20	$ 171,777	1,079	$180.00	$ 194,220	$180.00	$ 194,220
Number of Customers	1,080			1,080				
Economic Development Rider			$ (29,418)			$ (29,418)		$ (29,418)
Fuel			$ 19,059					
Subtotal			$ 12,884,930			$ 12,547,005		$ 12,547,005
DSM/EE Program Cost Rider - Non-Opt Out	161,264,401	$0.001706	$ 275,117	163,298,924	$0.000715	$ 116,759	$0.000715	$ 116,759
Off-System Sales & PJM Cost Rider - Energy (Up to 4,500 kWh)	157,514,748	$0.000512	$ 80,648	0	$0.022241	$ -	$0.022241	$ -
Off-System Sales & PJM Cost Rider - Energy (Over 4,500 kWh)		$0.000000	$ -	159,501,965	-$0.001587	$ (253,130)	-$0.001587	$ (253,130)
Off-System Sales & PJM Cost Rider - Demand	502,962	$6.319	$ 3,178,217	445,430	$7.276	$ 3,240,949	$7.276	$ 3,240,949
Life Cycle Management Rider - Energy (Up to 4,500 kWh)	157,514,748	$0.000000	$ -	0	$0.000012	$ -	$0.000012	$ -
Life Cycle Management Rider - Energy (Over 4,500 kWh)		$0.000000	$ -	159,501,965	$0.000000	$ -	$0.000000	$ -
Life Cycle Management Rider - Demand	502,962	$0.103	$ 51,805	445,430	$0.004	$ 1,782	$0.004	$ 1,782
Tax Rider - Energy (Up to 4,500 kWh)		$0.000000	$ -	0	-$0.002909	$ -	-$0.002909	$ -
Tax Rider - Energy (Over 4,500 kWh)		$0.000000	$ -	159,501,965	$0.000000	$ -	$0.000000	$ -
Tax Rider - Demand	502,962	$0.338	$ 170,001	445,430	-$0.888	$ (395,542)	-$0.888	$ (395,542)
Solar Power Rider - Energy (Up to 4,500 kWh)	157,514,748	$0.000000	$ -	0	$0.000181	$ -	$0.000181	$ -
Solar Power Rider - Energy (Over 4,500 kWh)		$0.000000	$ -	159,501,965	$0.000000	$ -	$0.000000	$ -
Solar Power Rider - Demand	502,962	$0.044	$ 22,130	445,430	$0.055	$ 24,499	$0.055	$ 24,499
Environmental Cost Rider - Energy (Up to 4,500 kWh)	157,514,748	-$0.000755	$ (118,924)	0	$0.000106	$ -	$0.000245	$ -
Environmental Cost Rider - Energy (Over 4,500 kWh)		$0.000000	$ -	159,501,965	$0.000106	$ 16,907	$0.000245	$ 39,078
Environmental Cost Rider - Demand	502,962	$0.003	$ 1,509	445,430	$0.000	$ -	$0.410	$ 182,626
Resource Adequacy Rider - Energy (Up to 4,500 kWh)	157,514,748	$0.000000	$ -	0	$0.005502	$ -	$0.000000	$ -
Resource Adequacy Rider - Energy (Over 4,500 kWh)		$0.000000	$ -	159,501,965	$0.000000	$ -	$0.000000	$ -
Resource Adequacy Rider - Demand	502,962	-$0.220	$ (110,652)	445,430	$1.680	$ 748,322	-$0.314	$ (139,865)
Phase in Rate - Energy (Up to 4,500 kWh)	157,514,748	-$0.000005	$ (788)	0	$0.001061	$ -	-$0.001527	$ -
Phase in Rate - Energy (Over 4,500 kWh)		$0.000000	$ -	159,501,965	$0.001525	$ 243,240	$0.000000	$ -
Phase in Rate - Demand	502,962	-$0.379	$ (190,623)	445,430	-$0.141	$ (62,806)	-$0.466	$ (207,570)
Total			$ 16,243,371			$16,227,986		$ 15,156,591

INDIANA MICHIGAN POWER COMPANY - INDIANA
PROFORMA
TEST YEAR ENDED DECEMBER 31, 2022

LARGE GENERAL SERVICE - SUBTRANSMISSION (248)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description (1)	Total (2)	Rate (3)	Revenue (4)=(2)x(3)	Total (5)	Rate (6)	Revenue (7)=(5)x(6)	Rate (8)	Revenue (9)=(5)x(8)
Billing kWh	3,566,907							
- First 300 kWh per kVA	2,770,246	$0.07209	$ 199,707					
- Over 300 kWh per kVA	796,661	$0.03726	$ 29,684					
Billing kWh				3,663,256				
- First 300 kWh per kW				2,504,505	$0.07175	$ 179,698	$0.07175	$ 179,698
- Over 300 kWh per kW				1,158,751	$0.02983	$ 34,566	$0.02983	$ 34,566
Metered kWh	3,663,256			3,663,256				
Billing kVA	9,236	$1.220	$ 11,268	628	$4.730	$ 2,970	$4.730	$ 2,970
Billing kW								
-All kW				8,339	$0.000	$ -	$0.000	$ -
Customer Charge	12	$159.20	$ 1,910	12	$180.00	$ 2,160	$180.00	$ 2,160
Number of Customers	12			12				
Fuel			$ 432					
Subtotal			$ 243,001			$ 219,394		$ 219,394
DSM/EE Program Cost Rider - Non-Opt Out	3,614,547	$0.001706	$ 6,166	3,712,183	$0.000715	$ 2,654	$0.000715	$ 2,654
Off-System Sales & PJM Cost Rider - Energy (Up to 4,500 kWh)	3,566,907	$0.000512	$ 1,826	0	$0.022241	$ -	$0.022241	$ -
Off-System Sales & PJM Cost Rider - Energy (Over 4,500 kWh)		$0.000000	$ -	3,663,256	-$0.001587	$ (5,814)	-$0.001587	$ (5,814)
Off-System Sales & PJM Cost Rider - Demand	9,236	$6.319	$ 58,362	8,339	$7.276	$ 60,675	$7.276	$ 60,675
Life Cycle Management Rider - Energy (Up to 4,500 kWh)	3,566,907	$0.000000	$ -	0	$0.000012	$ -	$0.000012	$ -
Life Cycle Management Rider - Energy (Over 4,500 kWh)		$0.000000	$ -	3,663,256	$0.000000	$ -	$0.000000	$ -
Life Cycle Management Rider - Demand	9,236	$0.103	$ 951	8,339	$0.004	$ 33	$0.004	$ 33
Tax Rider - Energy (Up to 4,500 kWh)	3,566,907	$0.000000	$ -	0	-$0.002909	$ -	-$0.002909	$ -
Tax Rider - Energy (Over 4,500 kWh)		$0.000000	$ -	3,663,256	$0.000000	$ -	$0.000000	$ -
Tax Rider - Demand	9,236	$0.338	$ 3,122	8,339	-$0.888	$ (7,405)	-$0.888	$ (7,405)
Solar Power Rider - Energy (Up to 4,500 kWh)	3,566,907	$0.000000	$ -	0	$0.000181	$ -	$0.000181	$ -
Solar Power Rider - Energy (Over 4,500 kWh)		$0.000000	$ -	3,663,256	$0.000000	$ -	$0.000000	$ -
Solar Power Rider - Demand	9,236	$0.044	$ 406	8,339	$0.055	$ 459	$0.055	$ 459
Environmental Cost Rider - Energy (Up to 4,500 kWh)	3,566,907	-$0.000755	$ (2,693)	0	$0.000106	$ -	$0.000245	$ -
Environmental Cost Rider - Energy (Over 4,500 kWh)		$0.000000	$ -	3,663,256	$0.000106	$ 388	$0.000245	$ 897
Environmental Cost Rider - Demand	9,236	$0.003	$ 28	8,339	$0.000	$ -	$0.410	$ 3,419
Resource Adequacy Rider - Energy (Up to 4,500 kWh)	3,566,907	$0.000000	$ -	0	$0.005502	$ -	$0.000000	$ -
Resource Adequacy Rider - Energy (Over 4,500 kWh)		$0.000000	$ -	3,663,256	$0.000000	$ -	$0.000000	$ -
Resource Adequacy Rider - Demand	9,236	-$0.220	$ (2,032)	8,339	$1.680	$ 14,010	-$0.314	$ (2,618)
Phase in Rate - Energy (Up to 4,500 kWh)	3,566,907	-$0.000005	$ (18)	0	$0.001061	$ -	-$0.001527	$ -
Phase in Rate - Energy (Over 4,500 kWh)		$0.000000	$ -	3,663,256	$0.001525	$ 5,586	$0.000000	$ -
Phase in Rate - Demand	9,236	-$0.379	$ (3,500)	8,339	-$0.141	$ (1,176)	-$0.466	$ (3,886)
Total			$ 305,619			$ 288,805		$ 267,808

INDUSTRIAL POWER SECONDARY (327)

Description	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description	Total	Rate	Revenue	Total	Rate	Revenue	Rate	Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
Billing kWh								
- First 410 kWh per kVA	415,138,222	$0.05510	$ 22,874,116					
- Over 410 kWh per kVA	63,087,860	$0.01160	$ 731,819					
- Minimum	951,468			710,182				
Billing kWh								
- First 410 kWh per kW				399,666,776	$0.05540	$ 22,141,539	$0.05540	$ 22,141,539
- Over 410 kWh per kW				92,641,156	$0.01104	$ 1,022,758	$0.01104	$ 1,022,758
Meter Voltage Adjustment	(593,211)			(593,211)				
Metered kWh	493,611,326			493,611,326				
Billing kVa	1,168,869	$14.486	$ 16,932,236					
Minimum Billing kVa	22,488	$18.750	$ 421,650					
Billed kW				1,079,576	$15.645	$ 16,889,967	$15.645	$ 16,889,967
Minimum Billed kW				15,504	$20.250	$ 313,956	$20.250	$ 313,956
Reactive Demand				52,974	$1.500	$ 79,461	$1.500	$ 79,461
Alternate Feed Service - per kW	27,408	$3.123	$ 85,595	27,408	$4.730	$ 129,640	$4.730	$ 129,640
Customer Charge	890	$115.00	$ 102,350	890	$155.00	$ 137,950	$155.00	$ 137,950
Alternate Feed Service - Customer Charge	12	$15.70	$ 188	12	$16.30	$ 196	$16.30	$ 196
Number of Customers	891			891				
Economic Development Rider			$ (26,339)			$ (26,339)		$ (26,339)
Fuel			$ 57,980					
Subtotal			$ 41,179,596			$ 40,689,127		$ 40,689,127
DSM/EE Program Cost Rider - Non-Opt Out	527,826,107	$0.001262	$ 666,117	543,071,837	$0.000495	$ 268,821	$0.000495	$ 268,821
DSM/EE Program Cost Rider - Opt Out	4,906,132	$0.000010	$ 49	5,047,841	$0.000009	$ 45	$0.000009	$ 45
Off-System Sales & PJM Cost Rider - Energy	479,177,550	$0.000512	$ 245,339	493,018,114	-$0.001587	$ (782,420)	-$0.001587	$ (782,420)
Off-System Sales & PJM Cost Rider - Demand	1,191,357	$8.282	$ 9,866,819	1,095,080	$9.190	$ 10,063,785	$9.190	$ 10,063,785
Life Cycle Management Rider - Energy	479,177,550	$0.000000	$ -	493,018,114	$0.000000	$ -	$0.000000	$ -
Life Cycle Management Rider - Demand	1,191,357	$0.129	$ 153,685	1,095,080	$0.004	$ 4,380	$0.004	$ 4,380
Tax Rider - Demand	1,191,357	$0.444	$ 528,963	1,095,080	-$1.122	$ (1,228,680)	-$1.122	$ (1,228,680)
Solar Power Rider - Energy	479,177,550	$0.000000	$ -	493,018,114	$0.000000	$ -	$0.000000	$ -
Solar Power Rider - Demand	1,191,357	$0.055	$ 65,525	1,095,080	$0.067	$ 73,370	$0.067	$ 73,370
Environmental Cost Rider - Energy	479,177,550	-$0.000755	$ (361,779)	493,018,114	$0.000106	$ 52,260	$0.000245	$ 120,789
Environmental Cost Rider - Demand	1,191,357	$0.003	$ 3,574	1,095,080	$0.000	$ -	$0.498	$ 545,350
Resource Adequacy Rider - Energy	479,177,550	$0.000000	$ -	493,018,114	$0.000000	$ -	$0.000000	$ -
Resource Adequacy Rider - Demand	1,191,357	-$0.276	$ (328,815)	1,095,080	$2.039	$ 2,232,868	-$0.381	$ (417,225)
Phase in Rate - Energy	479,177,550	-$0.000003	$ (1,438)	493,018,114	$0.001533	$ 755,797	$0.000000	$ -
Phase in Rate - Demand	1,191,357	-$0.350	$ (416,975)	1,095,080	$0.032	$ 35,043	-$0.566	$ (619,815)
Total			$ 51,600,660			$ 52,164,397		$ 48,717,528

INDUSTRIAL POWER PRIMARY (322)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description (1)	Total (2)	Rate (3)	Revenue (4)=(2)x(3)	Total (5)	Rate (6)	Revenue (7)=(5)x(6)	Rate (8)	Revenue (9)=(5)x(8)
Billing kWh								
- First 410 kWh per kVA	1,501,099,522	$0.05263	$ 79,002,868					
- Over 410 kWh per kVA	279,275,016	$0.01125	$ 3,141,844					
- Minimum	1,881,672			1,857,303				
Billing kWh								
- First 410 kWh per kW				1,449,160,084	$0.05185	$ 75,138,950	$0.05185	$ 75,138,950
- Over 410 kWh per kW				393,931,999	$0.01067	$ 4,203,254	$0.01067	$ 4,203,254
Meter Voltage Adjustment	0			0				
Metered kWh	1,844,949,386			1,844,949,386				
Billing kVa	4,119,623	$12.255	$ 50,485,980					
Minimum Billing kVa	98,157	$16.410	$ 1,610,756					
Billed kW				3,835,395	$13.113	$ 50,293,535	$13.113	$ 50,293,535
Minimum Billed kW				90,651	$17.559	$ 1,591,741	$17.559	$ 1,591,741
Reactive Demand				86,959	$1.500	$ 130,439	$1.500	$ 130,439
Alternate Feed Service - per kW	115,812	$3.123	$ 361,681	115,812	$4.730	$ 547,791	$4.730	$ 547,791
Customer Charge	1,647	$178.00	$ 293,166	1,647	$235.00	$ 387,045	$235.00	$ 387,045
Alternate Feed Service - Customer Charge	72	$15.70	$ 1,130	72	$16.30	$ 1,174	$16.30	$ 1,174
D.R.S. 2 Customer Charge	12	$10.00	$ 120	12	$10.00	$ 120	$10.00	$ 120
Number of Customers	1,649			1,649				
Economic Development Rider			$ (63,377)			$ (63,377)		$ (63,377)
Fuel			$ 215,653					
Subtotal			$ 135,049,821			$ 132,230,671		$ 132,230,671
DSM/EE Program Cost Rider - Non-Opt Out	1,809,945,866	$0.001262	$ 2,284,152	1,873,613,062	$0.000495	$ 927,438	$0.000495	$ 927,438
DSM/EE Program Cost Rider - Opt Out	170,805,028	$0.000010	$ 1,708	176,813,317	$0.000009	$ 1,591	$0.000009	$ 1,591
Off-System Sales & PJM Cost Rider - Energy	1,782,256,210	$0.000512	$ 912,515	1,844,949,386	-$0.001587	$ (2,927,935)	-$0.001587	$ (2,927,935)
Off-System Sales & PJM Cost Rider - Demand	4,217,780	$8.282	$ 34,931,654	3,926,046	$9.190	$ 36,080,363	$9.190000	$ 36,080,363
Life Cycle Management Rider - Energy	1,782,256,210	$0.000000	$ -	1,844,949,386	$0.000000	$ -	$0.000000	$ -
Life Cycle Management Rider - Demand	4,217,780	$0.129	$ 544,094	3,926,046	$0.004	$ 15,704	$0.004	$ 15,704
Tax Rider - Demand	4,217,780	$0.444	$ 1,872,694	3,926,046	-$1.122	$ (4,405,024)	-$1.122000	$ (4,405,024)
Solar Power Rider - Energy	1,782,256,210	$0.000000	$ -	1,844,949,386	$0.000000	$ -	$0.000000	$ -
Solar Power Rider - Demand	4,217,780	$0.055	$ 231,978	3,926,046	$0.067	$ 263,045	$0.067	$ 263,045
Environmental Cost Rider - Energy	1,782,256,210	-$0.000755	$ (1,345,603)	1,844,949,386	$0.000106	$ 195,565	$0.000245	$ 452,013
Environmental Cost Rider - Demand	4,217,780	$0.003	$ 12,653	3,926,046	$0.000	$ -	$0.498	$ 1,955,171
Resource Adequacy Rider - Energy	1,782,256,210	$0.000000	$ -	1,844,949,386	$0.000000	$ -	$0.000000	$ -
Resource Adequacy Rider - Demand	4,217,780	-$0.276	$ (1,164,107)	3,926,046	$2.039	$ 8,005,208	-$0.381	$ (1,495,824)
Phase in Rate - Energy	1,782,256,210	-$0.000003	$ (5,347)	1,844,949,386	$0.001533	$ 2,828,307	$0.000000	$ -
Phase in Rate - Demand	4,217,780	-$0.350	$ (1,476,223)	3,926,046	$0.032	$ 125,633	-$0.566	$ (2,222,142)
Total			$ 171,849,989			$ 173,340,568		$ 160,875,073

INDIANA MICHIGAN POWER COMPANY - INDIANA
PROFORMA
TEST YEAR ENDED DECEMBER 31, 2022

INDUSTRIAL POWER - SUBTRANSMISSION (323)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description	Total	Rate	Revenue	Total	Rate	Revenue	Rate	Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
Billing kWh								
- First 410 kWh per kVA	559,075,434	$0.05164	$ 28,870,655					
- Over 410 kWh per kVA	138,514,604	$0.01109	$ 1,536,127					
- Minimum	1,878,871			2,045,595				
Billing kWh								
- First 410 kWh per kW				534,234,761	$0.04940	$ 26,391,197	$0.04940	$ 26,391,197
- Over 410 kWh per kW				187,069,522	$0.01053	$ 1,969,842	$0.01053	$ 1,969,842
Meter Voltage Adjustment	611,832			611,832				
Metered kWh	722,738,046			722,738,046				
Billing kVa	1,524,863	$9.122	$ 13,909,800					
Minimum Billing kVa	33,472	$13.219	$ 442,466					
Billed kW				1,410,279	$10.034	$ 14,150,739	$10.034	$ 14,150,739
Minimum Billed kW				30,449	$14.541	$ 442,759	$14.541	$ 442,759
Reactive Demand				48,167	$1.500	$ 72,251	$1.500	$ 72,251
Customer Charge	227	$178.00	$ 40,406	227	$235.00	$ 53,345	$235.00	$ 53,345
Number of Customers	228			228				
Economic Development Rider			$ (34,953)			$ (34,953)		$ (34,953)
Fuel			$ 84,636					
Subtotal			$ 44,849,138			$ 43,045,181		$ 43,045,181
DSM/EE Program Cost Rider - Non-Opt Out	591,636,217	$0.001262	$ 746,645	611,835,608	$0.000495	$ 302,859	$0.000495	$ 302,859
DSM/EE Program Cost Rider - Opt Out	185,912,923	$0.000010	$ 1,859	192,260,283	$0.000009	$ 1,730	$0.000009	$ 1,730
Off-System Sales & PJM Cost Rider - Energy	699,468,909	$0.000512	$ 358,128	723,349,878	-$0.001587	$ (1,147,956)	-$0.001587	$ (1,147,956)
Off-System Sales & PJM Cost Rider - Demand	1,558,335	$8.282	$ 12,906,130	1,440,728	$9.190	$ 13,240,290	$9.190	$ 13,240,290
Life Cycle Management Rider - Energy	699,468,909	$0.000000	$ -	723,349,878	$0.000000	$ -	$0.000000	$ -
Life Cycle Management Rider - Demand	1,558,335	$0.129	$ 201,025	1,440,728	$0.004	$ 5,763	$0.004	$ 5,763
Tax Rider - Demand	1,558,335	$0.444	$ 691,901	1,440,728	-$1.122	$ (1,616,497)	-$1.122000	$ (1,616,497)
Solar Power Rider - Energy	699,468,909	$0.000000	$ -	723,349,878	$0.000000	$ -	$0.000000	$ -
Solar Power Rider - Demand	1,558,335	$0.055	$ 85,708	1,440,728	$0.067	$ 96,529	$0.067	$ 96,529
Environmental Cost Rider - Energy	699,468,909	-$0.000755	$ (528,099)	723,349,878	$0.000106	$ 76,675	$0.000245	$ 177,221
Environmental Cost Rider - Demand	1,558,335	$0.003	$ 4,675	1,440,728	$0.000	$ -	$0.498	$ 717,483
Resource Adequacy Rider - Energy	699,468,909	$0.000000	$ -	723,349,878	$0.000000	$ -	$0.000000	$ -
Resource Adequacy Rider - Demand	1,558,335	-$0.276	$ (430,100)	1,440,728	$2.039	$ 2,937,644	-$0.381	$ (548,917)
Phase in Rate - Energy	699,468,909	-$0.000003	$ (2,098)	723,349,878	$0.001533	$ 1,108,895	$0.000000	$ -
Phase in Rate - Demand	1,558,335	-$0.350	$ (545,417)	1,440,728	$0.032	$ 46,103	-$0.566	$ (815,452)
Total			$ 58,339,495			$ 58,097,217		$ 53,458,232

INDUSTRIAL POWER - TRANSMISSION (324)

Description	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
	Total	Rate	Revenue	Total	Rate	Revenue	Rate	Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
Billing kWh								
- First 410 kWh per kVA	175,841,382	$0.05158	$ 9,069,898					
- Over 410 kWh per kVA	21,538,514	$0.01098	$ 236,493					
- Minimum	2,593,879			2,894,233				
Billing kWh								
- First 410 kWh per kW				159,826,207	$0.04547	$ 7,267,298	$0.04547	$ 7,267,298
- Over 410 kWh per kW				39,637,078	$0.01045	$ 414,207	$0.01045	$ 414,207
Meter Voltage Adjustment	186,725			186,725				
Metered kWh	202,170,793			202,170,793				
Billing kVa	493,798	$9.016	$ 4,452,083					
Minimum Billing kVa	52,886	$13.067	$ 691,061					
Billed kW				425,541	$9.918	$ 4,220,516	$9.918	$ 4,220,516
Minimum Billed kW				77,733	$14.374	$ 1,117,334	$14.374	$ 1,117,334
Reactive Demand				73,873	$1.500	$ 110,810	$1.500	$ 110,810
Customer Charge	72	$178.00	$ 12,816	72	$235.00	$ 16,920	$235.00	$ 16,920
Number of Customers	72			72				
Fuel			$ 24,197					
Subtotal			$ 14,486,548			$ 13,147,084		$ 13,147,084
DSM/EE Program Cost Rider - Non-Opt Out	222,156,897	$0.001262	$ 280,362	224,805,069	$0.000495	$ 111,279	$0.000495	$ 111,279
Off-System Sales & PJM Cost Rider - Energy	199,973,775	$0.000512	$ 102,387	202,357,518	-$0.001587	$ (321,141)	-$0.001587	$ (321,141)
Off-System Sales & PJM Cost Rider - Demand	546,684	$8.282	$ 4,527,637	503,274	$9.190	$ 4,625,088	$9.190	$ 4,625,088
Life Cycle Management Rider - Energy	199,973,775	$0.000000	$ -	202,357,518	$0.000000	$ -	$0.000	$ -
Life Cycle Management Rider - Demand	546,684	$0.129	$ 70,522	503,274	$0.004	$ 2,013	$0.004	$ 2,013
Tax Rider - Demand	546,684	$0.444	$ 242,728	503,274	-$1.122	$ (564,673)	-$1.122	$ (564,673)
Solar Power Rider - Energy	199,973,775	$0.000000	$ -	202,357,518	$0.000000	$ -	$0.000000	$ -
Solar Power Rider - Demand	546,684	$0.055	$ 30,068	503,274	$0.067	$ 33,719	$0.067	$ 33,719
Environmental Cost Rider - Energy	199,973,775	-$0.000755	$ (150,980)	202,357,518	$0.000106	$ 21,450	$0.000245	$ 49,578
Environmental Cost Rider - Demand	546,684	$0.003	$ 1,640	503,274	$0.000	$ -	$0.498	$ 250,630
Resource Adequacy Rider - Energy	199,973,775	$0.000000	$ -	202,357,518	$0.000000	$ -	$0.000000	$ -
Resource Adequacy Rider - Demand	546,684	-$0.276	$ (150,885)	503,274	$2.039	$ 1,026,176	-$0.381	$ (191,747)
Phase in Rate - Energy	199,973,775	-$0.000003	$ (600)	202,357,518	$0.001533	$ 310,214	$0.000000	$ -
Phase in Rate - Demand	546,684	-$0.350	$ (191,339)	503,274	$0.032	$ 16,105	-$0.566	$ (284,853)
Total			$ 19,248,087			$ 18,407,313		$ 16,856,976

FORT WAYNE STREET LIGHTING (525)

	Current				Proposed (May-1, 2022 - Dec-31, 2022)				Proposed (As of Jan-1, 2023)		
Description (1)	Total (2)	Rate (3)		Revenue (4)=(2)x(3)	Total (5)	Rate (6)		Revenue (7)=(5)x(6)	Rate (8)		Revenue (9)=(5)x(8)
Billing kWh	22,506,643	$0.03230	$	726,965	22,506,643	$0.02996	$	674,299	$0.02996	$	674,299
Metered kWh	22,506,643				22,506,643						
Number of Customers	12				12						
Fuel			$	2,723							
Subtotal			$	729,688			$	674,299		$	674,299
DSM/EE Program Cost Rider - Non-Opt Out	23,837,778	$0.001706	$	40,667	23,837,778	$0.000715	$	17,044	$0.000715	$	17,044
Off-System Sales & PJM Cost Rider	22,506,643	$0.001838	$	41,367	22,506,643	-$0.000897	$	(20,188)	-$0.000897	$	(20,188)
Life Cycle Management Rider	22,506,643	$0.000022	$	495	22,506,643	$0.000000	$	-	$0.000000	$	-
Tax Rider	22,506,643	$0.000072	$	1,620	22,506,643	-$0.000084	$	(1,891)	-$0.000084	$	(1,891)
Solar Power Rider	22,506,643	$0.000008	$	180	22,506,643	$0.000005	$	113	$0.000005	$	113
Environmental Cost Rider	22,506,643	-$0.000754	$	(16,970)	22,506,643	$0.000106	$	2,386	$0.000284	$	6,392
Resource Adequacy Rider	22,506,643	-$0.000046	$	(1,035)	22,506,643	$0.000159	$	3,579	-$0.000030	$	(675)
Phase in Rate	22,506,643	-$0.001618	$	(36,416)	22,506,643	$0.000366	$	8,237	-$0.000044	$	(990)
Total			$	759,597			$	683,578		$	674,103

ENERGY CONSERVATION LIGHTING SERVICE (530)

Description	Current Total	Current Rate	Current Revenue	Proposed (May-1, 2022 - Dec-31, 2022) Total	Proposed (May-1, 2022 - Dec-31, 2022) Rate	Proposed (May-1, 2022 - Dec-31, 2022) Revenue	Proposed (As of Jan-1, 2023) Rate	Proposed (As of Jan-1, 2023) Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
On Wood Poles with Overhead Circuitry								
HIGH PRESSURE SODIUM								
5800 Lumen	5,201	7.35	$ 38,227	5,201	6.65	$ 34,587	6.65	$ 34,587
9500 Lumen	223,044	8.00	$ 1,784,352	223,044	7.25	$ 1,617,069	7.25	$ 1,617,069
22000 Lumen	67,420	12.00	$ 809,040	67,420	10.90	$ 734,878	10.90	$ 734,878
50000 Lumen	10,300	15.70	$ 161,710	10,300	14.25	$ 146,775	14.25	$ 146,775
Mercury Vapor								
7000 Lumen	1,143	8.65	$ 9,887	1,143	7.70	$ 8,801	7.70	$ 8,801
20000 Lumen	208	13.80	$ 2,870	208	12.30	$ 2,558	12.30	$ 2,558
On Metallic or Concrete Poles with Overhead Circuitry								
HIGH PRESSURE SODIUM								
5800 Lumen	230	16.60	$ 3,818	230	15.05	$ 3,462	15.05	$ 3,462
9500 Lumen	206	17.25	$ 3,554	206	15.60	$ 3,214	15.60	$ 3,214
22000 Lumen	4,526	18.80	$ 85,089	4,526	17.05	$ 77,168	17.05	$ 77,168
50000 Lumen	3,518	21.55	$ 75,813	3,518	19.55	$ 68,777	19.55	$ 68,777
On Metallic or Concrete Poles with Underground Circuitry								
HIGH PRESSURE SODIUM								
5800 Lumen	7	16.95	$ 119	7	15.35	$ 107	15.35	$ 107
9500 Lumen	11,252	18.15	$ 204,224	11,252	16.45	$ 185,095	16.45	$ 185,095
22000 Lumen	4,231	20.45	$ 86,524	4,231	18.55	$ 78,485	18.55	$ 78,485
50000 Lumen	6,268	23.20	$ 145,418	6,268	21.05	$ 131,941	21.05	$ 131,941
Post-Top Lamp on Fiberglass Pole with Underground Circuitry								
HIGH PRESSURE SODIUM								
9500 Lumen	-	14.85	$ -	-	13.45	$ -	13.45	$ -
LED								
5000 Lumen	-	15.90	$ -	-	15.90	$ -	15.90	$ -
7000 Lumen	-	16.45	$ -	-	16.45	$ -	16.45	$ -
8300 Lumen	-	21.25	$ -	-	21.25	$ -	21.25	$ -
Number of Customers	1,347			1,347				
Metered kWh	19,633,062			19,633,062				
Fuel			$ 2,376					
Subtotal			$ 3,413,020			$ 3,092,918		$ 3,092,918
DSM/EE Program Cost Rider - Non-Opt Out	20,795,543	$0.001706	$ 35,477	20,795,543	$0.000715	$ 14,869	$0.000715	$ 14,869
Off-System Sales & PJM Cost Rider	19,633,062	$0.001838	$ 36,086	19,633,062	-$0.000897	$ (17,611)	-$0.000897	$ (17,611)
Life Cycle Management Rider	19,633,062	$0.000022	$ 432	19,633,062	$0.000000	$ -	$0.000000	$ -
Tax Rider	19,633,062	$0.000072	$ 1,414	19,633,062	-$0.000084	$ (1,649)	-$0.000084	$ (1,649)
Solar Power Rider	19,633,062	$0.000008	$ 157	19,633,062	$0.000005	$ 98	$0.000005	$ 98
Environmental Cost Rider	19,633,062	-$0.000754	$ (14,803)	19,633,062	$0.000106	$ 2,081	$0.000284	$ 5,576
Resource Adequacy Rider	19,633,062	-$0.000046	$ (903)	19,633,062	$0.000159	$ 3,122	-$0.000030	$ (589)
Phase in Rate	19,633,062	-$0.001618	$ (31,766)	19,633,062	$0.000366	$ 7,186	-$0.000044	$ (864)
Total			$ 3,439,112			$ 3,101,013		$ 3,092,748

STREETLIGHTING - CUSTOMER-OWNED SYSTEM (531)

	Current				Proposed (May-1, 2022 - Dec-31, 2022)				Proposed (As of Jan-1, 2023)		
Description	Total	Rate		Revenue	Total	Rate		Revenue	Rate		Revenue
(1)	(2)	(3)		(4)=(2)x(3)	(5)	(6)		(7)=(5)x(6)	(8)		(9)=(5)x(8)
HIGH PRESSURE SODIUM											
5800 Lumen	-	2.05	$	-	-	1.85	$	-	1.85	$	-
9500 Lumen	17,296	2.45	$	42,375	17,296	2.25	$	38,916	2.25	$	38,916
14400 Lumen	1,319	3.40	$	4,485	1,319	3.10	$	4,089	3.10	$	4,089
16000 Lumen	372	3.40	$	1,265	372	3.10	$	1,153	3.10	$	1,153
22000 Lumen	6,861	4.30	$	29,502	6,861	3.95	$	27,101	3.95	$	27,101
25500 Lumen	2,384	5.75	$	13,708	2,384	5.25	$	12,516	5.25	$	12,516
50000 Lumen	2,894	8.15	$	23,586	2,894	7.45	$	21,560	7.45	$	21,560
MERCURY VAPOR											
7000 Lumen	6,728	4.15	$	27,921	6,728	3.80	$	25,566	3.80	$	25,566
11000 Lumen	481	5.65	$	2,718	481	5.15	$	2,477	5.15	$	2,477
20000 Lumen	560	8.55	$	4,788	560	7.80	$	4,368	7.80	$	4,368
LED											
Up to 50W	64	0.60	$	38	64	0.55	$	35	0.55	$	35
51W to 100W	415	1.30	$	540	415	1.20	$	498	1.20	$	498
101W to 150W	-	2.05	$	-	-	1.90	$	-	1.90	$	-
151W to 250W	20	3.20	$	64	20	2.90	$	58	2.90	$	58
Number of Customers	1,478				1,478						
Metered kWh	2,672,813				2,672,813						
Fuel			$	323							
Subtotal			$	151,313			$	138,338		$	138,338
DSM/EE Program Cost Rider - Non-Opt Out	2,827,908	$0.001706	$	4,824	2,827,908	$0.000715	$	2,022	$0.000715	$	2,022
Off-System Sales & PJM Cost Rider	2,672,813	$0.001838	$	4,913	2,672,813	-$0.000897	$	(2,398)	-$0.000897	$	(2,398)
Life Cycle Management Rider	2,672,813	$0.000022	$	59	2,672,813	$0.000000	$	-	$0.000000	$	-
Tax Rider	2,672,813	$0.000072	$	192	2,672,813	-$0.000084	$	(225)	-$0.000084	$	(225)
Solar Power Rider	2,672,813	$0.000008	$	21	2,672,813	$0.000005	$	13	$0.000005	$	13
Environmental Cost Rider	2,672,813	-$0.000754	$	(2,015)	2,672,813	$0.000106	$	283	$0.000284	$	759
Resource Adequacy Rider	2,672,813	-$0.000046	$	(123)	2,672,813	$0.000159	$	425	-$0.000030	$	(80)
Phase in Rate	2,672,813	-$0.001618	$	(4,325)	2,672,813	$0.000366	$	978	-$0.000044	$	(118)
Total			$	154,860			$	139,438		$	138,313

STREETLIGHTING SERVICE (533)

Description	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description	Total	Rate	Revenue	Total	Rate	Revenue	Rate	Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
On Wood Poles with Overhead Circuitry								
MERCURY VAPOR								
7000 Lumen	23,217	$8.90	$ 206,631	23,217	$7.95	$ 184,575	$7.95	$ 184,575
20000 Lumen	4,752	$13.35	$ 63,439	4,752	$11.90	$ 56,549	$11.90	$ 56,549
HIGH PRESSURE SODIUM								
16000 Lumen	454	$13.35	$ 6,061	454	$12.10	$ 5,493	$12.10	$ 5,493
25500 Lumen	129	$15.30	$ 1,974	129	$13.90	$ 1,793	$13.90	$ 1,793
On Metallic or Concrete Poles with Overhead Circuitry								
MERCURY VAPOR								
7000 Lumen	280	$13.55	$ 3,794	280	$12.10	$ 3,388	$12.10	$ 3,388
20000 Lumen	1,290	$18.90	$ 24,381	1,290	$16.85	$ 21,737	$16.85	$ 21,737
50000 Lumen	10	$29.65	$ 297	10	$26.45	$ 265	$26.45	$ 265
HIGH PRESSURE SODIUM								
16000 Lumen	216	$19.75	$ 4,266	216	$17.90	$ 3,866	$17.90	$ 3,866
25500 Lumen	192	$21.85	$ 4,195	192	$19.80	$ 3,802	$19.80	$ 3,802
On Metallic or Concrete Poles with Underground Circuitry								
INCANDESCENT								
1000 Lumen	1,624	$12.65	$ 20,544	1,624	$11.30	$ 18,351	$11.30	$ 18,351
2500 Lumen	20	$17.75	$ 355	20	$15.85	$ 317	$15.85	$ 317
4000 Lumen	10	$25.25	$ 253	10	$22.50	$ 225	$22.50	$ 225
MERCURY VAPOR								
7000 Lumen	580	$16.35	$ 9,483	580	$14.60	$ 8,468	$14.60	$ 8,468
20000 Lumen	214	$22.00	$ 4,708	214	$19.60	$ 4,194	$19.60	$ 4,194
HIGH PRESSURE SODIUM								
16000 Lumen	610	$24.85	$ 15,159	610	$22.55	$ 13,756	$22.55	$ 13,756
Traffic Control Signals	515	$2.85	$ 1,468	515	$2.60	$ 1,339	$2.60	$ 1,339
Number of Customers	460			460				
Metered kWh	2,737,356			2,737,356				
Fuel			$ 331					
Subtotal			$ 367,337			$ 328,118		$ 328,118
DSM/EE Program Cost Rider - Non-Opt Out	2,899,350	$0.001706	$ 4,946	2,899,350	$0.000715	$ 2,073	$0.000715	$ 2,073
Off-System Sales & PJM Cost Rider	2,737,356	$0.001838	$ 5,031	2,737,356	-$0.000897	$ (2,455)	-$0.000897	$ (2,455)
Life Cycle Management Rider	2,737,356	$0.000022	$ 60	2,737,356	$0.000000	$ -	$0.000000	$ -
Tax Rider	2,737,356	$0.000072	$ 197	2,737,356	-$0.000084	$ (230)	-$0.000084	$ (230)
Solar Power Rider	2,737,356	$0.000008	$ 22	2,737,356	$0.000005	$ 14	$0.000005	$ 14
Environmental Cost Rider	2,737,356	-$0.000754	$ (2,064)	2,737,356	$0.000106	$ 290	$0.000284	$ 777
Resource Adequacy Rider	2,737,356	-$0.000046	$ (126)	2,737,356	$0.000159	$ 435	-$0.000030	$ (82)
Phase in Rate	2,737,356	-$0.001618	$ (4,429)	2,737,356	$0.000366	$ 1,002	-$0.000044	$ (120)
Total			$ 370,975			$ 329,246		$ 328,094

INDIANA MICHIGAN POWER COMPANY - INDIANA
PROFORMA
TEST YEAR ENDED DECEMBER 31, 2022

STREET LIGHTING - CUSTOMER-OWNED SYSTEM-METERED (733, 734, 735)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description	Total	Rate	Revenue	Total	Rate	Revenue	Rate	Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
Billing kWh								
Single phase 120/240 volts	4,834,322	$0.03850	$ 186,121	4,834,322	$0.03468	$ 167,654	$0.03468	$ 167,654
Single phase 240/480 volts	3,664,881	$0.03850	$ 141,098	3,664,881	$0.03468	$ 127,098	$0.03468	$ 127,098
Three phase	164,977	$0.03850	$ 6,352	164,977	$0.03468	$ 5,721	$0.03468	$ 5,721
Metered kWh								
Single phase 120/240 volts	4,834,322			4,834,322				
Single phase 240/480 volts	3,664,881			3,664,881				
Three phase	164,977			164,977				
Customer Charge								
Single phase 120/240 volts	7,906	$6.65	$ 52,575	7,906	$6.65	$ 52,575	$6.65	$ 52,575
Single phase 240/480 volts	1,562	$13.75	$ 21,478	1,562	$13.75	$ 21,478	$13.75	$ 21,478
Three phase	38	$20.35	$ 773	38	$20.35	$ 773	$20.35	$ 773
Number of Customers								
Single phase 120/240 volts	7,909			7,909				
Single phase 240/480 volts	1,562			1,562				
Three phase	38			38				
Fuel			$ 1,048					
Subtotal			$ 409,445			$ 375,299		$ 375,299
DSM/EE Program Cost Rider - Non-Opt Out	9,174,329	$0.001706	$ 15,651	9,174,329	$0.000715	$ 6,560	$0.000715	$ 6,560
Off-System Sales & PJM Cost Rider	8,664,180	$0.001838	$ 15,925	8,664,180	-$0.000897	$ (7,772)	-$0.000897	$ (7,772)
Life Cycle Management Rider	8,664,180	$0.000022	$ 191	8,664,180	$0.000000	$ -	$0.000000	$ -
Tax Rider	8,664,180	$0.000072	$ 624	8,664,180	-$0.000084	$ (728)	-$0.000084	$ (728)
Solar Power Rider	8,664,180	$0.000008	$ 69	8,664,180	$0.000005	$ 43	$0.000005	$ 43
Environmental Cost Rider	8,664,180	-$0.000754	$ (6,533)	8,664,180	$0.000106	$ 918	$0.000284	$ 2,461
Resource Adequacy Rider	8,664,180	-$0.000046	$ (399)	8,664,180	$0.000159	$ 1,378	-$0.000030	$ (260)
Phase in Rate	8,664,180	-$0.001618	$ (14,019)	8,664,180	$0.000366	$ 3,171	-$0.000044	$ (381)
Total			$ 420,955			$ 378,870		$ 375,222

OUTDOOR LIGHTING (090, 092, 093, 094, 095, 097, 098, 100, 101, 102, 103, 105, 106, 107, 108, 109, 110, 112, 114, 115, 116, 119, 120, 121, 130, 143, 146)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description (1)	Total (2)	Rate (3)	Revenue (4)=(2)x(3)	Total (5)	Rate (6)	Revenue (7)=(5)x(6)	Rate (8)	Revenue (9)=(5)x(8)
Overhead Lighting Service								
Incandescent								
2,500 Lumens (090)	57	$10.40	$ 593	57	$9.25	$ 527	$9.25	$ 527
High Pressure Sodium								
100 watts, 9,500 Lumens (094)	204,035	$9.45	$ 1,928,131	204,035	$8.40	$ 1,713,894	$8.40	$ 1,713,894
200 watts, 22,000 Lumens (097)	56,063	$12.60	$ 706,394	56,063	$11.25	$ 630,709	$11.25	$ 630,709
400 watts, 50,000 Lumens (098)	18,659	$20.25	$ 377,845	18,659	$18.05	$ 336,795	$18.05	$ 336,795
5,800 Lumens (106)	619	$8.10	$ 5,014	619	$7.20	$ 4,457	$7.20	$ 4,457
25,500 Lumens (108)	94	$16.45	$ 1,546	94	$14.65	$ 1,377	$14.65	$ 1,377
** 9,500 Lumens (120) Special Contract	924	$5.75	$ 5,313	924	$5.15	$ 4,759	$5.15	$ 4,759
100 watts, 9,500 Lumens Post Top (121)	1,188	$25.15	$ 29,878	1,188	$22.40	$ 26,611	$22.40	$ 26,611
Mercury Vapor								
175 watts, 7,000 Lumens (093)	54,003	$10.85	$ 585,933	54,003	$9.65	$ 521,129	$9.65	$ 521,129
400 watts, 20,000 Lumens (095)	5,995	$18.20	$ 109,109	5,995	$16.20	$ 97,119	$16.20	$ 97,119
50,000 Lumens (100)	93	$32.70	$ 3,041	93	$29.15	$ 2,711	$29.15	$ 2,711
50,000 Lumens TA (102)	11	$32.70	$ 360	11	$29.15	$ 321	$29.15	$ 321
3,850 Lumens (103)	23	$10.30	$ 237	23	$9.20	$ 212	$9.20	$ 212
20,000 Lumens TC (105)	12	$18.20	$ 218	12	$16.20	$ 194	$16.20	$ 194
LED								
57 watts, 5,700 Lumens (130)	812	$7.35	$ 5,968	812	$6.55	$ 5,319	$6.55	$ 5,319
Flood Lighting Service								
High Pressure Sodium								
50,000 Lumens TC (101)	113	$19.70	$ 2,226	113	$17.60	$ 1,989	$17.60	$ 1,989
22,000 Lumens (107)	33,764	$14.15	$ 477,761	33,764	$12.60	$ 425,426	$12.60	$ 425,426
50,000 Lumens (109)	61,718	$19.70	$ 1,215,845	61,718	$17.60	$ 1,086,237	$17.60	$ 1,086,237
22,000 Lumens TA (112)	43	$14.15	$ 608	43	$12.60	$ 542	$12.60	$ 542
9,500 Lumens (115)	517	$14.15	$ 7,316	517	$12.60	$ 6,514	$12.60	$ 6,514
Metal Halide								
17,000 Lumens (110)	3,379	$15.40	$ 52,037	3,379	$13.75	$ 46,461	$13.75	$ 46,461
28,800 Lumens (116)	17,900	$19.20	$ 343,680	17,900	$17.15	$ 306,985	$17.15	$ 306,985
Mercury Vapor								
20,000 Lumens (114)	2,893	$20.75	$ 60,030	2,893	$18.50	$ 53,521	$18.50	$ 53,521
50,000 Lumens (119)	957	$37.65	$ 36,031	957	$33.55	$ 32,107	$33.55	$ 32,107
LED								
150 watts, 18,800 Lumens (143)	203	$12.85	$ 2,609	203	$11.45	$ 2,324	$11.45	$ 2,324
297 watts, 37,800 Lumens (146)	945	$18.55	$ 17,530	945	$16.55	$ 15,640	$16.55	$ 15,640
Facilities Charge								
MH 28,800 Lumens TC (092)	0	($2.60)	$ -	0	($2.35)	$ -	($2.35)	$ -
MV 50,000 Lumens TA (102)	11	($4.45)	$ (49)	11	($4.00)	$ (44)	($4.00)	$ (44)
MV 20,000 Lumens TC (105)	12	($2.60)	$ (31)	12	($2.35)	$ (28)	($2.35)	$ (28)
HPSF 50,000 Lumens TC (101)	113	($2.75)	$ (311)	113	($2.45)	$ (277)	($2.45)	$ (277)
HPSF 22,000 Lumens TA (112)	43	($1.10)	$ (47)	43	($1.00)	$ (43)	($1.00)	$ (43)
Pole								
30 FT Wood	84,036	$1.60	$ 134,458	84,036	$1.60	$ 134,458	$1.60	$ 134,458
35 FT Wood	44,304	$2.35	$ 104,114	44,304	$2.35	$ 104,114	$2.35	$ 104,114
40 FT Wood	10,668	$3.30	$ 35,204	10,668	$3.30	$ 35,204	$3.30	$ 35,204
Span	149,305	$1.25	$ 186,631	149,305	$1.25	$ 186,631	$1.25	$ 186,631
Lateral	18,842	$6.05	$ 113,994	18,842	$6.05	$ 113,994	$6.05	$ 113,994
Base Revenue			$ 6,549,214			$ 5,897,889		$ 5,897,889
Fuel Clause	38,349,500		$ 4,640	38,349,500				
Total			$ 6,553,854			$ 5,897,889		$ 5,897,889
Off-System Sales & PJM Cost Rider	38,349,500	$0.001788	$ 68,569	38,349,500	-$0.000922	$ (35,358)	-$0.000922	$ (35,358)
Life Cycle Management Rider	38,349,500	$0.000021	$ 805	38,349,500	$0.000000	$ -	$0.000000	$ -
Tax Rider	38,349,500	$0.000068	$ 2,608	38,349,500	-$0.000081	$ (3,106)	-$0.000081	$ (3,106)
Solar Power Rider	38,349,500	$0.000009	$ 345	38,349,500	$0.000005	$ 192	$0.000005	$ 192
Environmental Cost Rider	38,349,500	-$0.000754	$ (28,916)	38,349,500	$0.000106	$ 4,065	$0.000282	$ 10,815
Resource Adequacy Rider	38,349,500	-$0.000044	$ (1,687)	38,349,500	$0.000153	$ 5,867	-$0.000029	$ (1,112)
Phase in Rate	38,349,500	-$0.003417	$ (131,040)	38,349,500	-$0.001351	$ (51,810)	-$0.000043	$ (1,649)
Total			$ 6,464,538			$ 5,817,738		$ 5,867,669

WATER AND SEWAGE SERVICE - SECONDARY (545)

Description	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description (1)	Total (2)	Rate (3)	Revenue (4)=(2)x(3)	Total (5)	Rate (6)	Revenue (7)=(5)x(6)	Rate (8)	Revenue (9)=(5)x(8)
Billing kWh - Standard	67,088,410			67,088,410				
- First 300 kWh per kW	49,435,406	$0.07523	$ 3,719,026	49,435,406	$0.07274	$ 3,595,931	$0.07274	$ 3,595,931
- Over 300 kWh per kW	17,653,004	$0.07333	$ 1,294,495	17,653,004	$0.07065	$ 1,247,185	$0.07065	$ 1,247,185
Metered kWh	67,636,445			67,636,445				
Minimum kW	0	$0.00	$ -	0	$0.000	$ -	$0.000	$ -
Customer Charge	5,059	$27.00	$ 136,593	5,059	$31.00	$ 156,829	$31.00	$ 156,829
Number of Customers	5,063			5,063				
Fuel			$ 8,118					
Subtotal			$ 5,158,231			$ 4,999,945		$ 4,999,945
DSM/EE Program Cost Rider - Non-Opt Out	67,253,077	$0.001706	$ 114,734	67,253,077	$0.000715	$ 48,086	$0.000715	$ 48,086
DSM/EE Program Cost Rider - Opt Out	2,165,543	$0.000011	$ 24	2,165,543	$0.000012	$ 26	$0.000012	$ 26
Off-System Sales & PJM Cost Rider - Energy	67,088,410	$0.016253	$ 1,090,388	67,088,410	$0.015882	$ 1,065,498	$0.015882	$ 1,065,498
Life Cycle Management Rider	67,088,410	$0.000253	$ 16,973	67,088,410	$0.000009	$ 604	$0.000009	$ 604
Tax Rider	67,088,410	$0.000846	$ 56,757	67,088,410	-$0.002133	$ (143,100)	-$0.002133	$ (143,100)
Solar Power Rider	67,088,410	$0.000109	$ 7,313	67,088,410	$0.000133	$ 8,923	$0.000133	$ 8,923
Environmental Cost Rider	67,088,410	-$0.000750	$ (50,316)	67,088,410	$0.000106	$ 7,111	$0.001230	$ 82,519
Resource Adequacy Rider	67,088,410	-$0.000544	$ (36,496)	67,088,410	$0.004034	$ 270,635	-$0.000754	$ (50,585)
Phase in Rate - Energy	67,088,410	-$0.000918	$ (61,587)	67,088,410	$0.001287	$ 86,343	-$0.001119	$ (75,072)
Total			$ 6,296,020			$ 6,344,071		$ 5,936,844

WATER AND SEWAGE SERVICE - SECONDARY TIME OF DAY (547)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description	Total	Rate	Revenue	Total	Rate	Revenue	Rate	Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
Billing kWh								
On-peak kWh	1,956,952	$0.09986	$ 195,421	1,956,952	$0.07925	$ 155,088	$0.07925	$ 155,088
Off-peak kWh	3,714,792	$0.05224	$ 194,061	3,714,792	$0.06118	$ 227,271	$0.06118	$ 227,271
Metered kWh	5,671,744			5,671,744				
Customer Charge	48	$27.00	$ 1,296	48	$31.00	$ 1,488	$31.00	$ 1,488
Number of Customers	48			48				
Fuel			$ 686					
Subtotal			$ 391,464			$ 383,847		$ 383,847
DSM/EE Program Cost Rider - Non-Opt Out	5,862,557	$0.001706	$ 10,002	5,862,557	$0.000715	$ 4,192	$0.000715	$ 4,192
Off-System Sales & PJM Cost Rider	5,671,744	$0.016253	$ 92,183	5,671,744	$0.015882	$ 90,079	$0.015882	$ 90,079
Life Cycle Management Rider	5,671,744	$0.000253	$ 1,435	5,671,744	$0.000009	$ 51	$0.000009	$ 51
Tax Rider	5,671,744	$0.000846	$ 4,798	5,671,744	-$0.002133	$ (12,098)	-$0.002133	$ (12,098)
Solar Power Rider	5,671,744	$0.000109	$ 618	5,671,744	$0.000133	$ 754	$0.000133	$ 754
Environmental Cost Rider	5,671,744	-$0.000750	$ (4,254)	5,671,744	$0.000106	$ 601	$0.001230	$ 6,976
Resource Adequacy Rider	5,671,744	-$0.000544	$ (3,085)	5,671,744	$0.004034	$ 22,880	-$0.000754	$ (4,276)
Phase in Rate	5,671,744	-$0.000918	$ (5,207)	5,671,744	$0.001287	$ 7,300	-$0.001119	$ (6,347)
Total			$ 487,954			$ 497,606		$ 463,178

WATER AND SEWAGE SERVICE - PRIMARY (546)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description	Total	Rate	Revenue	Total	Rate	Revenue	Rate	Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
Billing kWh - Standard	48,513,602							
- First 300 kWh per kW	31,747,707	$0.06671	$ 2,117,890	31,747,707	$0.06296	$ 1,998,740	$0.06296	$ 1,998,740
- Over 300 kWh per kW	16,765,895	$0.06484	$ 1,087,101	16,765,895	$0.06090	$ 1,021,043	$0.06090	$ 1,021,043
Metered kWh	49,420,825			49,420,825				
Minimum kW	0	$0.00	$ -	-	$0.00	$ -	$0.00	$ -
Customer Charge	169	$119.00	$ 20,111	169	$137.00	$ 23,153	$137.00	$ 23,153
Number of Customers	169			169				
Fuel			$ 5,870					
Subtotal			$ 3,230,971			$ 3,042,936		$ 3,042,936
DSM/EE Program Cost Rider - Non-Opt Out	35,464,416	$0.001706	$ 60,502	35,464,416	$0.000715	$ 25,357	$0.000715	$ 25,357
DSM/EE Program Cost Rider - Opt Out	14,732,041	$0.000011	$ 162	14,732,041	$0.000012	$ 177	$0.000012	$ 177
Off-System Sales & PJM Cost Rider - Energy	48,513,602	$0.016253	$ 788,492	48,513,602	$0.015882	$ 770,493	$0.015882	$ 770,493
Life Cycle Management Rider	48,513,602	$0.000253	$ 12,274	48,513,602	$0.000009	$ 437	$0.000009	$ 437
Tax Rider	48,513,602	$0.000846	$ 41,043	48,513,602	-$0.002133	$ (103,480)	-$0.002133	$ (103,480)
Solar Power Rider	48,513,602	$0.000109	$ 5,288	48,513,602	$0.000133	$ 6,452	$0.000133	$ 6,452
Environmental Cost Rider	48,513,602	-$0.000750	$ (36,385)	48,513,602	$0.000106	$ 5,142	$0.001230	$ 59,672
Resource Adequacy Rider	48,513,602	-$0.000544	$ (26,391)	48,513,602	$0.004034	$ 195,704	-$0.000754	$ (36,579)
Phase in Rate - Energy	48,513,602	-$0.000918	$ (44,535)	48,513,602	$0.001287	$ 62,437	-$0.001119	$ (54,287)
Total			$ 4,031,420			$ 4,005,656		$ 3,711,178

INDIANA MICHIGAN POWER COMPANY - INDIANA
PROFORMA
TEST YEAR ENDED DECEMBER 31, 2022

WATER AND SEWAGE SERVICE - SUBTRANSMISSION (542)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description (1)	Total (2)	Rate (3)	Revenue (4)=(2)x(3)	Total (5)	Rate (6)	Revenue (7)=(5)x(6)	Rate (8)	Revenue (9)=(5)x(8)
Billing kWh - Standard	9,286,324			9,286,324				
- First 300 kWh per kW	6,818,911	$0.05652	$ 385,405	6,818,911	$0.04983	$ 339,793	$0.04983	$ 339,793
- Over 300 kWh per kW	2,467,413	$0.05471	$ 134,992	2,467,413	$0.04784	$ 118,041	$0.04784	$ 118,041
Meter Voltage Adjustment	41,364			41,364				
Metered kWh	9,333,155			9,333,155				
Minimum kW	0	$0.00	$ -	0	$0.00	$ -	$0.00	$ -
Customer Charge	65	$119.00	$ 7,735	65	$137.00	$ 8,905	$137.00	$ 8,905
Number of Customers	65			65				
Fuel			$ 1,124					
Subtotal			$ 529,256			$ 466,739		$ 466,739
DSM/EE Program Cost Rider - Non-Opt Out	6,945,900	$0.001706	$ 11,850	6,945,900	$0.000715	$ 4,966	$0.000715	$ 4,966
DSM/EE Program Cost Rider - Opt Out	2,658,427	$0.000011	$ 29	2,658,427	$0.000012	$ 32	$0.000012	$ 32
Off-System Sales & PJM Cost Rider - Energy	9,286,324	$0.016253	$ 150,931	9,286,324	$0.015882	$ 147,485	$0.015882	$ 147,485
Life Cycle Management Rider	9,286,324	$0.000253	$ 2,349	9,286,324	$0.000009	$ 84	$0.000009	$ 84
Tax Rider	9,286,324	$0.000846	$ 7,856	9,286,324	-$0.002133	$ (19,808)	-$0.002133	$ (19,808)
Solar Power Rider	9,286,324	$0.000109	$ 1,012	9,286,324	$0.000133	$ 1,235	$0.000133	$ 1,235
Environmental Cost Rider	9,286,324	-$0.000750	$ (6,965)	9,286,324	$0.000106	$ 984	$0.001230	$ 11,422
Resource Adequacy Rider	9,286,324	-$0.000544	$ (5,052)	9,286,324	$0.004034	$ 37,461	-$0.000754	$ (7,002)
Phase in Rate - Energy	9,286,324	-$0.000918	$ (8,525)	9,286,324	$0.001287	$ 11,951	-$0.001119	$ (10,391)
Total			$ 682,742			$ 651,131		$ 594,763

ELECTRIC HEAT GENERAL (208)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description	Total	Rate	Revenue	Total	Rate	Revenue	Rate	Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
Billing kWh	4,489,291	$0.07869	$ 353,262	4,489,291	$0.06475	$ 290,682	$0.06475	$ 290,682
Metered kWh	4,489,291			4,489,291				
Billing kW	26,998	$6.241	$ 168,495	26,998	$7.548	$ 203,781	$7.55	$ 203,781
Customer Charge	1,623	$18.75	$ 30,431	1,623	$25.00	$ 40,575	$25.00	$ 40,575
Number of Customers	1,623			1,623				
Fuel			$ 543					
Subtotal			$ 552,731			$ 535,037		$ 535,037
DSM/EE Program Cost Rider - Non-Opt Out	5,820,056	$0.001970	$ 11,466	5,820,056	$0.000715	$ 4,161	$0.000715	$ 4,161
Off-System Sales & PJM Cost Rider - Energy	4,489,291	$0.000512	$ 2,299	4,489,291	-$0.001586	$ (7,120)	-$0.001586	$ (7,120)
Off-System Sales & PJM Cost Rider - Demand	26,998	$4.400	$ 118,791	26,998	$4.789	$ 129,293	$4.789	$ 129,293
Life Cycle Management Rider - Demand	26,998	$0.072	$ 1,944	26,998	$0.002	$ 54	$0.002	$ 54
Tax Rider - Demand	26,998	$0.236	$ 6,372	26,998	-$0.585	$ (15,794)	-$0.585	$ (15,794)
Solar Power Rider - Demand	26,998	$0.031	$ 837	26,998	$0.036	$ 972	$0.036	$ 972
Environmental Cost Rider - Energy	4,489,291	-$0.000755	$ (3,389)	4,489,291	$0.000106	$ 476	$0.000245	$ 1,100
Environmental Cost Rider - Demand	26,998	$0.002	$ 54	26,998	$0.000	$ -	$0.270	$ 7,289
Resource Adequacy Rider - Energy	4,489,291	$0.000000	$ -	4,489,291	$0.000000	$ -	$0.000000	$ -
Resource Adequacy Rider - Demand	26,998	-$0.153	$ (4,131)	26,998	$1.106	$ 29,860	-$0.207	$ (5,589)
Phase in Rate - Energy	4,489,291	-$0.000004	$ (18)	4,489,291	$0.001526	$ 6,851	$0.000000	$ -
Phase in Rate - Demand	26,998	-$0.270	$ (7,289)	26,998	-$0.153	$ (4,131)	-$0.307	$ (8,288)
Total			$ 679,665			$ 679,660		$ 641,117

IRRIGATION SERVICE (213)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description	Total	Rate	Revenue	Total	Rate	Revenue	Rate	Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)
Billing kWh	1,248,480	$0.19516	$ 243,653	1,248,480	$0.16667	$ 208,084	$0.16667	$ 208,084
Metered kWh	1,248,480			1,248,480				
Customer Charge	420	$0.00	$ -	420	$0.00	$ -	$0.00	$ -
Number of Customers	803			803				
Fuel			$ 151					
Subtotal			$ 243,804			$ 208,084		$ 208,084
DSM/EE Program Cost Rider - Non-Opt Out	740,112	$0.001970	$ 1,458	740,112	$0.000715	$ 529	$0.000715	$ 529
Off-System Sales & PJM Cost Rider	1,248,480	$0.015984	$ 19,956	1,248,480	$0.019800	$ 24,720	$0.019800	$ 24,720
Life Cycle Management Rider	1,248,480	$0.000251	$ 313	1,248,480	$0.000010	$ 12	$0.000010	$ 12
Tax Rider	1,248,480	$0.000831	$ 1,037	1,248,480	-$0.002611	$ (3,260)	-$0.002611	$ (3,260)
Solar Power Rider	1,248,480	$0.000112	$ 140	1,248,480	$0.000163	$ 204	$0.000163	$ 204
Environmental Cost Rider	1,248,480	-$0.000747	$ (933)	1,248,480	$0.000106	$ 132	$0.001452	$ 1,813
Resource Adequacy Rider	1,248,480	-$0.000535	$ (668)	1,248,480	$0.004939	$ 6,166	-$0.000923	$ (1,152)
Phase in Rate	1,248,480	-$0.002662	$ (3,323)	1,248,480	-$0.000766	$ (956)	-$0.001370	$ (1,710)
Total Revenue			$ 261,785			$ 235,632		$ 229,239

MUNICIPAL SERVICE (543, 544)

	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
Description (1)	Total (2)	Rate (3)	Revenue (4)=(2)x(3)	Total (5)	Rate (6)	Revenue (7)=(5)x(6)	Rate (8)	Revenue (9)=(5)x(8)
Billing kWh	22,107,814			22,107,814				
- First 4,500 kWh	8,691,621	$0.10678	$ 928,091	8,691,621	$0.10061	$ 874,473	$0.10061	$ 874,473
- Over 4,500 kWh	13,416,193	$0.07597	$ 1,019,228	13,416,193	$0.06673	$ 895,263	$0.06673	$ 895,263
Metered kWh	22,107,814			22,107,814				
Billing kW								
-Over 10kW	68,830	$6.241	$ 429,568	68,830	$7.548	$ 519,529	$7.548	$ 519,529
Customer Charge	3,680	$20.25	$ 74,520	3,680	$20.25	$ 74,520	$20.25	$ 74,520
Number of Customers	3,679			3,679				
Fuel			$ 2,675					
Subtotal			$ 2,454,082			$ 2,363,784		$ 2,363,784
DSM/EE Program Cost Rider - Non-Opt Out	29,357,217	$0.001706	$ 50,083	29,357,217	$0.000715	$ 20,990	$0.000715	$ 20,990
DSM/EE Program Cost Rider - Opt Out	0	$0.000011	$ -	0	$0.000012	$ -	$0.000012	$ -
Off-System Sales & PJM Cost Rider	22,107,814	$0.026196	$ 579,136	22,107,814	$0.023954	$ 529,571	$0.023954	$ 529,571
Life Cycle Management Rider	22,107,814	$0.000417	$ 9,219	22,107,814	$0.000013	$ 287	$0.000013	$ 287
Tax Rider	22,107,814	$0.001378	$ 30,465	22,107,814	-$0.003118	$ (68,932)	-$0.003118	$ (68,932)
Solar Power Rider	22,107,814	$0.000180	$ 3,979	22,107,814	$0.000194	$ 4,289	$0.000194	$ 4,289
Environmental Cost Rider	22,107,814	-$0.000745	$ (16,470)	22,107,814	$0.000106	$ 2,343	$0.001686	$ 37,274
Resource Adequacy Rider	22,107,814	-$0.000894	$ (19,764)	22,107,814	$0.005898	$ 130,392	-$0.001102	$ (24,363)
Phase in Rate	22,107,814	-$0.001555	$ (34,378)	22,107,814	$0.000953	$ 21,069	-$0.001637	$ (36,190)
Total			$ 3,056,352			$ 3,003,793		$ 2,826,710

PUBLIC VERSION

INDIANA MICHIGAN POWER COMPANY - INDIANA
PROFORMA
TEST YEAR ENDED DECEMBER 31, 2022
INTERRUPTIBLE (329, 330, 332, 375)

Description	Current			Proposed (May-1, 2022 - Dec-31, 2022)			Proposed (As of Jan-1, 2023)	
	Total	Rate	Revenue	Total	Rate	Revenue	Rate	Revenue
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)	(9)=(5)x(8)

Firm Usage
Demand - IP Primary
Demand - IP Subtrans
Demand - IP Trans
Billing Energy - IP Primary
- First 410 kWh per kVA
- Over 410 kWh per kVA
Billing Energy - IP Subtrans
- First 410 kWh per kVA
- Over 410 kWh per kVA
Billing Energy - IP Trans
- First 410 kWh per kVA
- Over 410 kWh per kVA

Met. kWh - Primary (IP)
Met. kWh - Subtrans (IP)
Met. kWh - Trans (IP)
Metered kWh

Customer Charge
- IP Primary
- IP Subtran
- IP Tran

Number of Customers

Fuel

Subtotal

DSM/EE Program Cost Rider - Non Opt Out
DSM/EE Program Cost Rider - Opt Out
Off-System Sales & PJM Cost Rider - Energy
Off-System Sales & PJM Cost Rider - Demand
Life Cycle Management Rider - Energy
Life Cycle Management Rider - Demand
Tax Rider - Demand
Solar Power Rider - Energy
Solar Power Rider - Demand
Environmental Cost Rider - Energy
Environmental Cost Rider - Demand
Resource Adequacy Rider - Energy
Resource Adequacy Rider - Demand
Phase in Rate - Energy
Phase in Rate - Demand

Total

Interruptible Usage
Demand - IP Pri
Demand - IP Trans

IRP Demand Credit
IRP Demand Credit
IRP Demand Credit

Billing Energy - IP Primary (First 410 kWh per kVA)
Billing Energy - IP Primary (Over 410 kWh per kVA)
Billing Energy - IP Transmission (First 410 kWh per kVA)
Billing Energy - IP Transmission (Over 410 kWh per kVA

Special Contract Energy Only
Special Contract Energy - TRAN (standard FAC)
Special Contract - SUB (standard FAC)
Buy-Thru
Discretionary Interruptible
Taxes and Assessments

Revenue Subtotal

Metered kWh

Customer Charge (QP Subtran)

Number of Customers

Fuel

Demand Subtotal
Energy Subtotal
Subtotal

DSM/EE Program Cost Rider - Non Opt Out
DSM/EE Program Cost Rider - Opt Out
Off-System Sales & PJM Cost Rider - Energy
Off-System Sales & PJM Cost Rider - Demand
Life Cycle Management Rider - Energy
Life Cycle Management Rider - Demand
Tax Rider - Demand
Solar Power Rider - Energy
Solar Power Rider - Demand
Environmental Cost Rider - Energy
Environmental Cost Rider - Demand
Resource Adequacy Rider - Energy
Resource Adequacy Rider - Demand
Phase in Rate - Energy
Phase in Rate - Demand
Imputed Revenue - Solar Power Rider
Imputed Revenue - Resource Adequacy Rider
Imputed Revenue - Life Cycle Mgt Rider
Imputed Revenue - ECR

Demand
Energy
Total

Total Usage
Metered kWh
Number of Customers
Base Billing Excluding Fuel
Fuel Billing
Base Billing
Riders Other Than Fuel
Total Billing

[redacted]

FAC Current Fuel Calculation

	Total Fuel (1)	FAC in Base Rates (2)	FAC Factor (3) = (1) - (2)
Indiana	0.0131100	0.0129890	0.000121

Sources:

(1) thru (3) / FAC Basing Point Calculation prepared by Company witness Heimberger
(2) / I&M Indiana Tariff Sheet No.44, Fuel Cost Adjustment Rider issued March 11, 2020

Indiana Jurisdiction
For the Forecasted Test Year Ended December 31, 2022
Summary of Billing Energy and Total Fuel Revenues

Tariff Class	Billing kWh	Total Fuel Rate (Base Fuel + FAC)	Total Fuel ($)
RS	4,213,912,529	0.013110	55,244,393
RS-Flat Bill	8,241,300	0.013110	108,043
RS TOD	26,452,128	0.013110	346,787
RS TOD 2	1,099,470	0.013110	14,414
OL	38,349,500	0.013110	502,762
GS SEC	1,028,509,503	0.013110	13,483,760
GS SEC-Flat B	738,051	0.013110	9,676
GS LMTOD	3,214,893	0.013110	42,147
GS TOD2	16,955	0.013110	222
GS NM	550,524	0.013110	7,217
GS TOD SEC	44,449,361	0.013110	582,731
GS TOD PRI	553	0.013110	7
GS PRI	27,866,219	0.013110	365,326
GS SUB	6,738,742	0.013110	88,345
GS TRAN	387,555	0.013110	5,081
LGS SEC	2,487,504,788	0.013110	32,611,188
LGS LMTOD	8,833,465	0.013110	115,807
LGS TOD SEC	66,503,602	0.013110	871,862
LGS TOD PRI	465,405	0.013110	6,101
LGS PRI	157,514,748	0.013110	2,065,018
LGS SUB	3,566,907	0.013110	46,762
IP SEC	479,177,550	0.013110	6,282,018
IP PRI	1,782,256,210	0.013110	23,365,379
IP SUB	699,468,909	0.013110	9,170,037
IP TRAN	199,973,775	0.013110	2,621,656
FW SL	22,506,643	0.013110	295,062
ECLS	19,633,062	0.013110	257,389
SLC	2,672,813	0.013110	35,041
SLS	2,737,356	0.013110	35,887
SLCM	8,664,180	0.013110	113,587
WSS SEC	67,088,410	0.013110	879,529
WSS TOD	5,671,744	0.013110	74,357
WSS PRI	48,513,602	0.013110	636,013
WSS SUB	9,286,324	0.013110	121,744
IS	1,248,480	0.013110	16,368
EHG	4,489,291	0.013110	58,855
MS	22,107,814	0.013110	289,833
IRP - FIRM	301,821,230	0.013110	3,956,876
IRP - INTERR	2,597,189,866	0.013110	34,049,159
Total Indiana	14,399,423,457		188,776,442

Indiana Michigan Power Company
State of Indiana
Distribution Allocator - Base Rate Revenue Requirement

Tariff (1)	*Base Revenue (2)	% of Total (3)	Transmission Customer Adjustment (4)	Base Rate Revenue Requirement Adjusted for Transmission Customers (5) = (2) + (4)	% of Total / Distribution Allocator (6)
Residential	$ 536,840,475	45.341%		$536,840,475	48.308%
OL Total (090 - 120)	$ 5,897,889	0.498%		$5,897,889	0.531%
GS Secondary	$ 131,310,739	11.090%		$131,310,739	11.816%
GS Primary	$ 2,836,929	0.240%		$2,836,929	0.255%
GS Subtransmission	$ 537,297	0.045%	($537,297)	$0	0.000%
GS Transmission	$ 35,126	0.003%	($35,126)	$0	0.000%
LGS Secondary	$ 232,742,629	19.657%		$232,742,629	20.944%
LGS Primary	$ 12,588,055	1.063%		$12,588,055	1.133%
LGS Subtransmission	$ 219,394	0.019%	($219,394)	$0	0.000%
IP Secondary	$ 40,689,127	3.437%		$40,689,127	3.661%
IP Primary	$ 132,230,671	11.168%		$132,230,671	11.899%
IP Subtransmission	$ 43,045,181	3.636%	($43,045,181)	$0	0.000%
IP Transmission	$ 28,427,716	2.401%	($28,427,716)	$0	0.000%
SL	$ 4,608,972	0.389%		$4,608,972	0.415%
WSS Secondary	$ 5,383,793	0.455%		$5,383,793	0.484%
WSS Primary	$ 3,042,936	0.257%		$3,042,936	0.274%
WSS Subtransmission	$ 466,739	0.039%	($466,739)	$0	0.000%
IS	$ 208,084	0.018%		$208,084	0.019%
EHG	$ 535,037	0.045%		$535,037	0.048%
MS	$ 2,363,784	0.200%		$2,363,784	0.213%
Total	$1,184,010,573	100%	($72,731,452)	$1,111,279,121	100%

* I&M Indiana Proforma Firm Revenues from Cause # 45576

Indiana Michigan Power Company
State of Indiana
Transmission Allocator - Base Rate Revenue Requirement

Tariff (1)	*Base Revenue (2)	% of Total / Transmission Allocator (3)
Residential	$536,840,475	45.341%
OL Total (090 - 120)	$5,897,889	0.498%
GS Secondary	$131,310,739	11.090%
GS Primary	$2,836,929	0.240%
GS Subtransmission	$537,297	0.045%
GS Transmission	$35,126	0.003%
LGS Secondary	$232,742,629	19.657%
LGS Primary	$12,588,055	1.063%
LGS Subtransmission	$219,394	0.019%
IP Secondary	$40,689,127	3.437%
IP Primary	$132,230,671	11.168%
IP Subtransmission	$43,045,181	3.636%
IP Transmission	$28,427,716	2.401%
SL	$4,608,972	0.389%
WSS Secondary	$5,383,793	0.455%
WSS Primary	$3,042,936	0.257%
WSS Subtransmission	$466,739	0.039%
IS	$208,084	0.018%
EHG	$535,037	0.045%
MS	$2,363,784	0.200%
Total	$1,184,010,573	100%

* I&M Indiana Proforma Firm Revenues from Cause # 45576

Indiana Michigan Power Company - Indiana
Typical Electric Bill Comparison

Line No.	Tariff	Demand	Metered Energy	Current Bill	Proposed Bill	Bill Increase	% Change
	RS						
1	Block 1 - up to 900 kWh	--	250	$50.87	$50.51	-$0.36	-0.7%
2	Block 2 - all other kWh	--	500	$86.75	$86.00	-$0.75	-0.9%
3		--	750	$122.61	$121.52	-$1.09	-0.9%
4		--	1,000	$157.82	$156.34	-$1.48	-0.9%
5		--	2,000	$294.56	$291.64	-$2.92	-1.0%
6		--	4,000	$568.08	$562.22	-$5.86	-1.0%
	RS-OPES						
7	On-Peak=30%	--	250	$47.16	$48.26	$1.10	2.3%
8	Off-Peak=70%	--	500	$77.82	$79.48	$1.66	2.1%
9		--	750	$108.46	$110.75	$2.29	2.1%
10		--	1,000	$139.12	$142.00	$2.88	2.1%
11		--	2,000	$261.72	$266.98	$5.26	2.0%
12		--	4,000	$506.95	$516.94	$9.99	2.0%
	RS-TOD						
13	On-Peak 30%	--	500	$77.82	$79.48	$1.66	2.1%
14	Off-Peak 70%	--	1,000	$139.12	$142.00	$2.88	2.1%
15		--	2,000	$261.72	$266.98	$5.26	2.0%
16		--	3,000	$384.35	$391.97	$7.62	2.0%
17		--	4,000	$506.95	$516.94	$9.99	2.0%
18		--	5,000	$629.59	$641.96	$12.37	2.0%
	RS-TOD2						
19	On-Peak 5%	--	500	$83.64	$85.22	$1.58	1.9%
20	Off-Peak 95%	--	1,000	$152.28	$153.47	$1.19	0.8%
21		--	2,000	$289.54	$289.94	$0.40	0.1%
22		--	3,000	$426.83	$426.39	-$0.44	-0.1%
23		--	4,000	$564.10	$562.84	-$1.26	-0.2%
24		--	5,000	$701.39	$699.33	-$2.06	-0.3%
	GS-SEC <10 kW						
25	*See Note 1*	3 kW	250	$55.53	$58.02	$2.49	4.5%
26		3 kW	500	$92.06	$91.01	-$1.05	-1.1%
27		5 kW	1,000	$165.13	$157.01	-$8.12	-4.9%
28		7 kW	2,500	$384.28	$355.03	-$29.25	-7.6%
29		9 kW	5,000	$731.49	$666.62	-$64.88	-8.9%
	GS-TOD2						
30	On-Peak 5%	--	1,000	$160.53	$155.58	-$4.95	-3.1%
31	Off-Peak 95%	--	2,500	$372.78	$351.43	-$21.35	-5.7%
32		--	5,000	$726.63	$677.88	-$48.75	-6.7%
33		--	7,500	$1,080.40	$1,004.30	-$76.10	-7.0%
	GS-OUSP						
34	Optional Unmetered	--	100	$22.42	$22.93	$0.51	2.3%
35	Service Provision	--	250	$44.04	$42.64	-$1.40	-3.2%
36		--	500	$80.07	$75.45	-$4.62	-5.8%
37		--	1,000	$152.16	$141.09	-$11.07	-7.3%
38		--	2,000	$296.29	$272.37	-$23.92	-8.1%
	GS-SEC						
39	*See Note 1*	10 kW	2,000	$311.23	$289.00	-$22.23	-7.1%
40		10 kW	3,000	$457.36	$421.03	-$36.33	-7.9%
41		10 kW	4,000	$603.47	$553.02	-$50.45	-8.4%
42		10 kW	5,000	$731.49	$666.62	-$64.88	-8.9%
43		100 kW	20,000	$2,941.33	$3,084.60	$143.27	4.9%
44		100 kW	25,000	$3,490.74	$3,560.45	$69.70	2.0%
45		100 kW	30,000	$4,040.11	$4,036.29	-$3.83	-0.1%
46		500 kW	100,000	$14,227.97	$15,100.12	$872.14	6.1%

Indiana Michigan Power Company - Indiana
Typical Electric Bill Comparison

Line No.	Tariff	Demand	Metered Energy	Current Bill	Proposed Bill	Bill Increase	% Change
	GS-TOD-SEC						
47	On-Peak 40%	--	100	$30.95	$36.62	$5.67	18.3%
48	Off-Peak 60%	--	250	$48.86	$54.07	$5.21	10.7%
49		--	500	$78.72	$83.11	$4.39	5.6%
50		--	1,000	$138.45	$141.22	$2.77	2.0%
51		--	2,000	$257.89	$257.42	-$0.47	-0.2%
52		--	4,000	$496.79	$489.85	-$6.94	-1.4%
	GS-LM-TOD						
53	On-Peak 30%	--	500	$73.99	$79.60	$5.61	7.6%
54	Off-Peak 70%	--	1,000	$128.99	$134.19	$5.20	4.0%
55		--	2,000	$238.96	$243.35	$4.39	1.8%
56		--	2,500	$293.93	$297.98	$4.05	1.4%
57		--	3,000	$348.94	$352.56	$3.62	1.0%
58		--	4,000	$458.91	$461.72	$2.81	0.6%
59		--	5,000	$568.92	$570.94	$2.02	0.4%
	GS-PRI						
60	*See Note 1*	300 kW	60,000	$7,970.48	$8,459.02	$488.54	6.1%
	GS-SUB						
61	*See Note 1*	100 kW	40,000	$4,662.26	$4,223.69	-$438.57	-9.4%
	GS-TRAN						
62	*See Note 1*	200 kW	17,500	$2,368.68	$3,234.55	$865.87	36.6%
	LGS-SEC						
63	*See Note 2*	100 kW	35,000	$3,853.99	$4,053.53	$199.54	5.2%
64		100 kW	40,000	$4,049.21	$4,216.52	$167.31	4.1%
65		100 kW	50,000	$4,439.63	$4,542.51	$102.88	2.3%
66		100 kW	60,000	$4,830.07	$4,868.50	$38.43	0.8%
67		500 kW	175,000	$19,152.02	$20,166.10	$1,014.08	5.3%
68		500 kW	200,000	$20,128.09	$20,981.07	$852.98	4.2%
69		500 kW	250,000	$22,080.24	$22,611.02	$530.78	2.4%
70		500 kW	300,000	$24,032.39	$24,240.97	$208.58	0.9%
	LGS-PRI						
71	*See Note 2*	500 kW	175,000	$17,869.19	$18,434.08	$564.89	3.2%
72		500 kW	200,000	$18,818.48	$19,210.55	$392.07	2.1%
73		500 kW	250,000	$20,717.08	$20,763.50	$46.42	0.2%
74		500 kW	300,000	$22,615.67	$22,316.45	-$299.22	-1.3%
	LGS-SUB						
75	*See Note 2*	900 kW	150,000	$17,857.10	$18,425.38	$568.28	3.2%
76		900 kW	250,000	$24,966.16	$25,676.28	$710.12	2.8%
77		900 kW	350,000	$30,206.60	$29,573.58	-$633.02	-2.1%
78		900 kW	450,000	$33,954.56	$32,632.48	-$1,322.08	-3.9%
	LGS-LM-TOD						
79	On-Peak 30%	--	15,000	$1,581.82	$1,662.79	$80.97	5.1%
80	Off-Peak 70%	--	25,000	$2,612.83	$2,754.64	$141.81	5.4%
81		--	35,000	$3,643.84	$3,846.49	$202.65	5.6%
	LGS-TOD-SEC						
82	On-Peak 45%	50 kW	20,000	$2,152.92	$2,241.66	$88.74	4.1%
83	Off-Peak 55%	100 kW	50,000	$5,044.35	$5,179.50	$135.15	2.7%
84		100 kW	60,000	$5,818.16	$5,899.68	$81.52	1.4%
	LGS-TOD-PRI						
85	On-Peak 40%	400 kW	150,000	$14,706.95	$14,998.85	$291.90	2.0%
86	Off-Peak 60%	400 kW	200,000	$18,318.00	$18,243.00	-$75.00	-0.4%
87		400 kW	250,000	$21,929.05	$21,487.15	-$441.90	-2.0%

Indiana Michigan Power Company - Indiana
Typical Electric Bill Comparison

Line No.	Tariff	Demand	Metered Energy	Current Bill	Proposed Bill	Bill Increase	% Change
	IP-SEC						
88	Block 1 - 1st 410 kWh/kVA	1,000 kW	250,000	$37,662.17	$39,996.75	$2,334.58	6.2%
89	Block 2 - all other kWh	1,000 kW	350,000	$43,089.04	$45,591.45	$2,502.41	5.8%
90		1,500 kW	550,000	$65,921.37	$69,708.35	$3,786.98	5.7%
91		1,500 kW	650,000	$71,348.25	$73,750.45	$2,402.20	3.4%
92		1,500 kW	750,000	$73,453.45	$74,909.15	$1,455.70	2.0%
	IP-PRI						
93	Block 1 - 1st 410 kWh/kVA	3,000 kW	1,000,000	$116,934.78	$122,601.00	$5,666.22	4.8%
94	Block 2 - all other kWh	3,000 kW	1,500,000	$136,557.82	$137,680.90	$1,123.08	0.8%
95		3,000 kW	2,000,000	$142,534.54	$143,289.40	$754.86	0.5%
	IP-SUB						
96	Block 1 - 1st 410 kWh/kVA	7,500 kW	2,000,000	$239,481.68	$251,959.00	$12,477.32	5.2%
97	Block 2 - all other kWh	7,500 kW	3,000,000	$290,411.48	$301,906.00	$11,494.52	4.0%
98		7,500 kW	4,000,000	$316,076.61	$315,898.25	-$178.36	-0.1%
	IP-TRAN						
99		7,500 kW	3,000,000	$289,400.91	$289,246.00	-$154.91	-0.1%
100		7,500 kW	4,000,000	$314,976.99	$302,869.50	-$12,107.49	-3.8%
101		10,000 kW	6,000,000	$427,682.59	$411,079.00	-$16,603.59	-3.9%
	MS						
102	Block 1 - up to 4,500 kWh	40 kW	8,000	$1,168.33	$1,162.71	-$5.62	-0.5%
103	Block 2 - all other kWh	40 kW	10,000	$1,373.87	$1,353.61	-$20.26	-1.5%
104		40 kW	12,000	$1,579.41	$1,544.51	-$34.90	-2.2%
	WSS-SEC						
105	Block 1 - First 300 kWh/kW	50 kW	15,000	$1,411.61	$1,422.61	$11.00	0.8%
106	Block 2 - all other kWh	50 kW	17,500	$1,637.62	$1,649.32	$11.70	0.7%
107		50 kW	20,000	$1,863.62	$1,876.01	$12.39	0.7%
	WSS-PRI						
108	Block 1 - First 300 kWh/kW	750 kW	250,000	$21,018.75	$20,833.08	-$185.67	-0.9%
109	Block 2 - all other kWh	750 kW	300,000	$25,114.55	$24,879.73	-$234.82	-0.9%
110		750 kW	400,000	$33,306.15	$32,973.03	-$333.12	-1.0%
	WSS-SUB						
111	Block 1 - First 300 kWh/kW	750 kW	250,000	$18,472.75	$17,553.23	-$919.52	-5.0%
112	Block 2 - all other kWh	750 kW	300,000	$22,062.05	$20,946.88	-$1,115.17	-5.1%
113		750 kW	400,000	$29,240.65	$27,734.18	-$1,506.47	-5.2%
	WSS-TOD-SEC						
114	On-Peak 30%	--	100,000	$8,387.20	$8,694.40	$307.20	3.7%
115	Off-Peak 70%	--	200,000	$16,747.40	$17,357.80	$610.40	3.6%
	IS						
116		--	1,000	$210.47	$189.03	-$21.44	-10.2%
117		--	2,500	$526.21	$472.58	-$53.63	-10.2%
118		--	4,000	$841.93	$756.11	-$85.82	-10.2%
	EHG						
119		25 kW	3,500	$564.61	$572.86	$8.25	1.5%
120		25 kW	4,000	$604.86	$605.61	$0.75	0.1%
121		25 kW	4,500	$645.13	$638.38	-$6.75	-1.0%

Note 1: GS - Current side energy blocking is Block 1 - up to 4,500 kWh, Block 2 - over 4,500 kWh. Proposed energy blocking same as current.

Note 2: LGS - Current side energy blocking is Block 1 -First 300 kWh per kVa, Block 2 - over 300 kWh per kVa. Proposed energy blocking is Block 1 - FIrst 300 kWh/kW, Block 2 - over 300 kWh/kW.

INDIANA MICHIGAN POWER COMPANY
NET PLANT: SETTLEMENT
AS OF DECEMBER 31, 2022
(Dollars)

(1) Line No.	(2) Description	(3) IN Retail Settlement
1	101 ELECTRIC PLANT IN SERVICE (a)	7,462,197,124
2	108 ACCUM. PROV. FOR DEPRECIATION (a)	(2,616,142,625)
3	NET PLANT	**4,846,054,499**
4	LESS TRANSMISSION	
5	101 ELECTRIC PLANT IN SERVICE (a)	**1,287,833,242**
6	108 ACCUM. PROV. FOR DEPRECIATION (a)	**(327,252,885)**
7	TRANSMISSION NET PLANT	**960,580,357**
8	FORECASTED NET PLANT (b)	**3,885,474,142**
	(a) Excludes leased assets (b)For Phase-in rate adjustment reconciliation	

INDIANA MICHIGAN POWER COMPANY
Computation of Gross Revenue Conversion Factor
For the Test Year Ended December 31, 2022

		Tax Rates	Percentage of Incremental Gross Revenues
1	Operating Revenues		100.00%
2	Less: Uncollectible Accounts Expense		0.3935%
3	Income Before Income Taxes		99.61%
4	Less: Indiana Utility Receipts Tax	1.4000%	
5	Public Utility Assessment Fee (IURC)	0.1274%	1.5214%
6	Base Subject to State Income Taxes		98.0851%
7	Less: State Income Taxes (Line 6 x Effective State Tax Rate)	4.9714%	4.8762%
8	Income Before Federal Income Taxes		93.2089%
9	Less: Federal Income Taxes (Line 8 x Federal Tax Rate)	21.00%	19.5739%
10	Operating Income Percentage		73.6350%
11	Gross Revenue Conversion Factor (100% / Line 10)		1.3580

INDIANA MICHIGAN POWER COMPANY
EFFECTIVE FEDERAL INCOME TAX RATE
TEST YEAR ENDED DECEMBER 31, 2022

Line No.	Description		Jurisdictional Amount
1	Adjusted Net Electric Operating Income	$	357,455,166
2	Plus: Federal Income Tax Expense		54,598,886
3	Pre-Tax Electric Operating Income	$	412,054,052
4	Less: Interest Expense - Synchronized		92,624,789
5	Pre-Tax Operating Income Before Federal Income Tax	$	319,429,263
6	Effective Tax Rate - Line 2 divided by Line 5		17.09%

INTERNAL REVENUE
BULLETIN

IRS

HIGHLIGHTS OF THIS ISSUE

Bulletin No. 2021–1
January 4, 2021

These synopses are intended only as aids to the reader in identifying the subject matter covered. They may not be relied upon as authoritative interpretations.

ADMINISTRATIVE

Rev. Proc. 2021-1, page 1.

This procedure contains revised procedures for letter rulings and information letters issued by the Associate Chief Counsel (Corporate), Associate Chief Counsel (Employee Benefits, Exempt Organizations, and Employment Taxes), Associate Chief Counsel (Financial Institutions and Products), Associate Chief Counsel (Income Tax and Accounting), Associate Chief Counsel (International), Associate Chief Counsel (Passthroughs and Special Industries), and Associate Chief Counsel (Procedure and Administration). This procedure also contains revised procedures for determination letters issued by the Large Business and International Division, Small Business/Self Employed Division, Wage and Investment Division, and Tax Exempt and Government Entities Division. Rev. Proc. 2020-1 superseded.

Rev. Proc. 2021-2, page 116.

This procedure explains when and how an Associate office within the Office of Chief Counsel provides technical advice, conveyed in technical advice memoranda (TAMs). It also explains the rights that a taxpayer has when a field office requests a TAM regarding a tax matter. Rev. Proc. 2020-2 superseded.

Rev. Proc. 2021-3, page 140.

The revenue procedure provides a revised list of areas of the Code under the jurisdiction of the Associate Chief Counsel (Corporate), the Associate Chief Counsel (Financial Institutions and Products), the Associate Chief Counsel (Income Tax and Accounting), the Associate Chief Counsel (Passthroughs and Special Industries), the Associate Chief Counsel (Procedure and Administration), and the Associate Chief Counsel (Employee Benefits, Exempt Organizations and Employment Taxes) relating to matters on which the Service will not issue letter rulings or determination letters. Rev. Proc. 2020-3, 2020-1 I.R.B. 131 is superseded.

Finding Lists begin on page ii.

EMPLOYEE PLANS

Rev. Proc. 2021-4, page 157.

This document updates Rev. Proc. 2020-4, 2020-1 I.R.B. 148, relating to the types of advice the IRS provides to taxpayers on issues under the jurisdiction of the Commissioner, Tax Exempt and Government Entities Division, Employee Plans Rulings and Agreements, and the procedures that apply to requests for determination letters and private letter rulings.

EXEMPT ORGANIZATIONS

Rev. Proc. 2021-5, page 250.

This revenue procedure sets forth procedures for issuing determination letters on issues under the jurisdiction of the Director, Exempt Organizations (EO) Rulings and Agreements. Specifically, it explains the procedures for issuing determination letters on tax-exempt status (in response to applications for recognition of exemption from Federal income tax under § 501 or § 521 other than those subject to Rev. Proc. 2021-4, this Bulletin (relating to pension, profit-sharing, stock bonus, annuity, and employee stock ownership plans)), private foundation status, and other determinations related to exempt organizations. These procedures also apply to revocation or modification of determination letters. This revenue procedure also provides guidance on the exhaustion of administrative remedies for purposes of declaratory judgment under § 7428. Finally, this revenue procedure provides guidance on applicable user fees for requesting determination letters.

INCOME TAX

Rev. Proc. 2021-7, page 290.

Areas in which rulings will not be issued, Associate Chief Counsel (International).

APPENDIX G
CHECKLISTS, GUIDELINE REVENUE PROCEDURES, NOTICES, SAFE HARBOR REVENUE PROCEDURES, AND AUTOMATIC CHANGE REVENUE PROCEDURES

Specific revenue procedures and notices supplement the general instructions for requests explained in section 7 of this revenue procedure and apply to requests for letter rulings or determination letters regarding the Code sections and matters listed in this section.

Checklists, guideline revenue procedures, and notices

.01 For requests relating to the following Code sections and subject matters, refer to the following checklists, guideline revenue procedures, and notices.

CODE OR REGULATION SECTION	*REVENUE PROCEDURE AND NOTICE*
103, 141 - 150, 1394, 1400L(d), 1400N(a), 1400U-1, 1400U-3, 7478, and 7871 Issuance of state or local obligations	Rev. Proc. 96-16, 1996-1 C.B. 630 (for a reviewable ruling under § 7478 and a nonreviewable ruling); Rev. Proc. 88-31, 1988-1 C.B. 832 (for approval of areas of chronic economic distress); and Rev. Proc. 82-26, 1982-1 C.B. 476 (for "on behalf of" and similar issuers). For approval of areas of chronic economic distress, Rev. Proc. 88-31 explains how this request for approval must be submitted to the Assistant Secretary for Housing/Federal Housing Commissioner of the Department of Housing and Urban Development.
1.166-2(d)(3) Uniform express determination letter for making election	Rev. Proc. 92-84, 1992-2 C.B. 489.
Subchapter C-Corporate Distributions, Adjustments, Transfers, and Reorganizations	Rev. Proc. 77-37, 1977-2 C.B. 568, as modified by Rev. Proc. 89-30, 1989-1 C.B. 895, and as amplified by Rev. Proc. 77-41, 1977-2 C.B. 574, Rev. Proc. 83-81, 1983-2 C.B. 598 (*see also* Rev. Proc. 2021-3, this Bulletin, Rev. Proc. 84-42, 1984-1 C.B. 521 (superseded, in part, as to no-rule areas by Rev. Proc. 2021-3, Rev. Proc. 86-42, 1986-2 C.B. 722, Rev. Proc. 89-50, 1989-2 C.B. 631, and Rev. Proc. 2017-52, 2017-41 I.R.B. 283 (relating to Transactional Rulings for Covered Transactions), and Rev. Proc. 2018-53, 2018-43 I.R.B. 667. *But see* section 3.01(59) of Rev. Proc. 2021-3, which states that the Service will not issue a letter ruling as to whether a transaction constitutes a reorganization within the meaning of § 368 (except as provided in section 6.03(2)(b) of this revenue procedure). However, the Service will issue a letter ruling addressing significant issues (within the meaning of section 3.01(59) of Rev. Proc. 2021-3) presented in a reorganization within the meaning of § 368. *See* section 6.03(2) of this revenue procedure. In addition, the Service will issue a Transactional ruling for a Covered Transaction, as described in Rev. Proc. 2017-52 (amplified and modified by Rev. Proc. 2018-53).
301 Nonapplicability on sales of stock of employer to defined contribution plan	Rev. Proc. 87-22, 1987-1 C.B. 718.
302, 311 Checklist questionnaire	Rev. Proc. 86-18, 1986-1 C.B. 551; and Rev. Proc. 77-41, 1977-2 C.B. 574.
302(b)(4) Checklist questionnaire	Rev. Proc. 81-42, 1981-2 C.B. 611.
311 Checklist questionnaire	Rev. Proc. 86-16, 1986-1 C.B. 546.
332 Checklist questionnaire	*See* section 3.01 of Rev. Proc. 2021-3, this Bulletin, which states that the Service will not issue a letter ruling on whether a corporate distribution qualifies for nonrecognition treatment under § 332. However, the Service will issue a letter ruling addressing significant issues (within the meaning of section 3.01 of Rev. Proc. 2021-3) presented in a transaction described in § 332. The information and representations described in Rev. Proc. 90-52, 1990-2 C.B. 626, should be included in a letter ruling request only to the extent that they relate to the significant issues with respect to which the letter ruling is requested. *See* section 6.03(3) of this revenue procedure.

338 Extension of time to make elections	Rev. Proc. 2003-33, 2003-1 C.B. 803, provides guidance as to how an automatic extension of time under § 301.9100-3 of the Treasury Regulations may be obtained to file elections under § 338. Rev. Proc. 2003-33 also informs taxpayers who do not qualify for the automatic extension of the information necessary to obtain a letter ruling.
351 Checklist questionnaire	*See* section 3.01 of Rev. Proc. 2021-3, this Bulletin, which states that the Service will not issue a letter ruling on whether certain transfers to controlled corporations qualify for nonrecognition treatment under § 351. However, the Service will issue a letter ruling addressing significant issues (within the meaning of section 3.01 of Rev. Proc. 2021-3) presented in a transaction described in § 351. The information and representations described in Rev. Proc. 83-59, 1983-2 C.B. 575, should be included in a letter ruling request only to the extent that they relate to the significant issues with respect to which the letter ruling is requested. *See* section 6.03(3) of this revenue procedure.
355 Checklist questionnaire	Rev. Proc. 2017-52, 2017-41 I.R.B. 283, and Rev. Proc. 2018-53, 2018-43 I.R.B. 667. *See also* section 6.03(2) of this revenue procedure.
368(a)(1)(E) Checklist questionnaire	*See* section 3.01 of Rev. Proc. 2021-3, this Bulletin, which states that the Service will not issue a letter ruling as to whether a transaction constitutes a reorganization, including a recapitalization within the meaning of § 368(a)(1)(E) (or a transaction that qualifies under § 1036). However, the Service will issue a letter ruling addressing significant issues (within the meaning of section 3.01 of Rev. Proc. 2021-3) presented in a transaction described in § 368(a)(1)(E) (or in a transaction described in § 1036). The information and representations described in Rev. Proc. 81-60, 1981-2 C.B. 680, should be included in a letter ruling request only to the extent that they relate to the significant issues. *See* section 6.03(3) of this revenue procedure.
412, 4971(b) Additional tax (on failure to meet minimum funding standards)	Rev. Proc. 81-44, 1981-2 C.B. 618, provides guidance for requesting a waiver of the 100 percent tax imposed under § 4971(b) on a pension plan that fails to meet the minimum funding standards of § 412.
412(c) Minimum funding standards	Rev. Proc. 2004-15, 2004-1 C.B. 490, provides guidance for requesting a waiver of the minimum funding standards.
412(c)(7)(B) Minimum funding standards - restrictions on plan amendments	Rev. Proc. 79-62, 1979-2 C.B. 576 provides guidance for requesting a determination that a plan amendment is reasonable and provides for only de minimis increases in plan liabilities in accordance with former § 412(f)(2)(A) (now § 412(c)(7)(B)(i)).
412(d)(2) Minimum funding standards - certain retroactive plan amendments	Rev. Proc. 94-42, 1994-1 C.B. 717, as modified by Rev. Proc. 2021-4 sets forth procedures under which a plan sponsor may file notice with and obtain approval for a retroactive amendment described in § 412(d)(2) (formerly § 412(c)(8)) and § 302(d)(2) of the Employee Retirement Income Security Act of 1974 (ERISA) that reduces prior accrued benefits.
414(e) Church plans	Rev. Proc. 2011-44, 2011-39 I.R.B. 445 provides supplemental procedures for requesting a ruling relating to church plans under section 414(e). Rev. Proc. 2011-44 provides that plan participants and other interested persons must receive a notice when a letter ruling is requested and a copy of the notice must be submitted as part of the ruling request. Rev. Proc. 2011-44 also provides procedures for the Service to receive and consider comments about the ruling request from interested persons. *See* Appendix E of this revenue procedure.
414(r) Qualified separate lines of business – administrative scrutiny	Rev. Proc. 93-41, 1993-2 C.B. 536, sets forth procedures relating to the issuance of an administrative scrutiny determination, which is a determination by the Service as to whether a separate line of business satisfies the requirement of administrative scrutiny, within the meaning of § 1.414(r)-6, for the testing year.
461(h) Alternative method for the inclusion of common improvement costs in basis	Rev. Proc. 92-29, 1992-1 C.B. 748.

482 Advance pricing agreements	Rev. Proc. 2015-40, 2015-35 I.R.B. 236, and Rev. Proc. 2015-41, 2015-35 I.R.B. 263.
521 Appeal procedure with regard to adverse determination letters and revocation or modification of exemption letter rulings and determination letters	Rev. Proc. 2021-5, this Bulletin.
817(h) Closing agreement for inadvertent failures of variable contracts	Rev. Proc. 2008-41, 2008-2 C.B. 155.
860 Self Determination of Deficiency Dividend	Rev. Proc. 2009-28, 2009-20 I.R.B. 1011.
877, 2107, and 2501(a)(3) Individuals who lose U.S. citizenship or cease to be taxed as long-term U.S. residents with a principal purpose to avoid U.S. taxes	Notice 97-19, 1997-1 C.B. 394, as modified by Notice 98-34, 1998-2 C.B. 29, and as obsoleted in part by Notice 2005-36, 2005-1 C.B. 1007.
1059(c)(4) Fair market value of stock for purposes of election	Rev. Proc. 86-33, 1987-29 C.B. 402, provides guidance to corporate taxpayers on how to make the election under section 1059(c)(4) and establish the fair market value of stock for purposes of that election. It provides an automatic procedure to value publicly traded stock and valuation procedures for other stock.
1362(b)(5) and 1362(f) Relief for late S corporation and related elections under certain circumstances	Rev. Proc. 2013-30, 2013-36 I.R.B. 173.
1362(b)(5) and 301.7701-3 Automatic extensions of time for late S corporation election and late corporate entity classification	Rev. Proc. 2013-30, 2013-36 I.R.B. 173.
1.1502-13(e)(3) Consent to treat intercompany transactions on a separate entity basis and revocation of this consent	Rev. Proc. 2009-31, 2009-27 I.R.B. 107.
1.1502-75(b) Consent to Be Included in a Consolidated Income Tax Return	Rev. Proc. 2014-24, 2014-13 I.R.B. 879, provides a determination that certain subsidiary corporations are treated as if they had filed a Form 1122, *Authorization and Consent of Subsidiary Corporation To Be Included in a Consolidated Income Tax Return*, even though they failed to do so. Rev. Proc. 2014-24 also informs taxpayers who do not qualify for the automatic determination of the procedure for requesting such determination.
1.1502-76(a)(1) Consent to file a consolidated return where member(s) of the affiliated group use a 52-53 week taxable year	Rev. Proc. 89-56, 1989-2 C.B. 643, as modified by Rev. Proc. 2006-21, 2006-1 C.B. 1050.

1504(a)(3)(A) and (B) Waiver of application of § 1504(a)(3)(A) for certain corporations	Rev. Proc. 2002-32, 2002-1 C.B. 959, as modified by Rev. Proc. 2006-21, 2006-1 C.B. 1050.
1552 Consent to elect or change method of allocating affiliated group's consolidated Federal income tax liability	Rev. Proc. 90-39, 1990-2 C.B. 365, as clarified by Rev. Proc. 90-39A, 1990-2 C.B. 367, and as modified by Rev. Proc. 2006-21, 2006-1 C.B. 1050.
2642 Allocations of generation-skipping transfer tax exemption	Rev. Proc. 2004-46, 2004-2 C.B. 142, provides an alternative method for requesting relief to make a late allocation of the generation-skipping transfer tax exemption. Rev. Proc. 2004-46 also informs taxpayers who are denied relief or who are outside the scope of the revenue procedure of the information necessary for obtaining a letter ruling.
2652(a)(3) Reverse qualified terminable interest property elections	Rev. Proc. 2004-47, 2004-2, C.B. 169, provides an alternative method for certain taxpayers to obtain an extension of time to make a late reverse qualified terminable interest property election under § 2652(a)(3). Rev. Proc. 2004-47 also informs taxpayers who are denied relief or who are outside the scope of the revenue procedure of the information necessary to obtain a letter ruling.
4980B Failure to satisfy continuation coverage requirements of group health plans	Rev. Proc. 87-28, 1987-1 C.B. 770 (treating references to former § 162(k) as if they were references to § 4980B).
7701 Relief for a late initial classification election for a newly formed entity	Rev. Proc. 2009-41, 2009-39 I.R.B. 439.
7701(a)(40) and 7871(d) Indian tribal governments and subdivision of Indian tribal governments	Rev. Proc. 84-37, 1984-1 C.B. 513, as modified by Rev. Proc. 86-17, 1986-1 C.B. 550, and this revenue procedure (provides guidelines for obtaining letter rulings recognizing Indian tribal government or tribal government subdivision status; also provides for inclusion in list of federally recognized Indian tribes published annually by the Department of the Interior, Bureau of Indian Affairs, or in list of recognized subdivisions of Indian tribal governments in revised versions of Rev. Proc. 84-36, 1984-1 C.B. 510, as modified and made permanent by Rev. Proc. 86-17).
301.7701-2(a) Classification of undivided fractional interests in rental real estate	Rev. Proc. 2002-22, 2002-1 C.B. 733 (specifies the conditions under which the Service will consider a letter ruling request that an undivided fractional interest in rental real property (other than a mineral property as defined in § 614) is not an interest in a business entity).
301.7701-3 Automatic extensions of time for late S corporation election and late corporate entity classification	Rev. Proc. 2013-30, 2013-36 I.R.B. 173.
301.9100-3 Extension of time to make entity classification election	Rev. Proc. 2009-41, 2009-39 I.R.B. 439.
7702 Closing agreement for failure to account for charges for qualified additional benefits	Rev. Proc. 2008-38, 2008-2 C.B. 139.
7702 Closing agreement for failed life insurance contracts	Rev. Proc. 2008-40, 2008-2 C.B. 151.

7702A Closing agreement for inadvertent non-egregious failure to comply with modified endowment contract rules	Rev. Proc. 2008-39, 2008-2 C.B. 143.
7704(g) Revocation of election	Notice 98-3, 1998-1 C.B. 333.
SUBJECT MATTERS	*REVENUE PROCEDURE*
Accounting periods; changes in period	Rev. Proc. 2002-39, 2002-1 C.B. 1046, as clarified and modified by Notice 2002-72, 2002-2 C.B. 843, as modified by Rev. Proc. 2003-34, 2003-1 C.B. 856, and modified by Rev. Proc. 2003-79, 2003-2 C.B. 1036; and this revenue procedure, for which sections 1, 2.01, 2.02, 2.05, 3.04, 5.02, 6.03, 6.05, 6.07, 6.11, 7.01(1), 7.01(2), 7.01(3), 7.01(4), 7.01(5), 7.01(6), 7.01(9), 7.01(10), 7.01(11), 7.01(14), 7.01(15), 7.01(16), 7.02(2), 7.02(4), 7.02(5), 7.02(6), 7.04, 7.05, 7.06, 7.08, 8.01, 8.03, 8.04, 8.05, 8.06, 10, 11, 15, 17, 18, Appendix A, and Appendix G are applicable.
Classification of liquidating trusts	Rev. Proc. 82-58, 1982-2 C.B. 847, as modified and amplified by Rev. Proc. 94-45, 1994-2 C.B. 684, and as amplified by Rev. Proc. 91-15, 1991-1 C.B. 484 (checklist questionnaire), as modified and amplified by Rev. Proc. 94-45.
Earnings and profits determinations	Rev. Proc. 75-17, 1975-1 C.B. 677; this revenue procedure, sections 2.05, 3.04, 7, 8, and 10.05; and Rev. Proc. 2021-3, this Bulletin, section 3.01.
Estate, gift, and generation-skipping transfer tax issues	Rev. Proc. 91-14, 1991-1 C.B. 482 (checklist questionnaire).
Intercompany transactions; election not to defer gain or loss	Rev. Proc. 2009-31, 2009-27 I.R.B. 107.
Leveraged leasing	Rev. Proc. 2001-28, 2001-1 C.B. 1156, and Rev. Proc. 2001-29, 2001-1 C.B. 1160.
Rate orders; regulatory agency; normalization	A letter ruling request that involves a question of whether a rate order that is proposed or issued by a regulatory agency will meet the normalization requirements of § 168(f)(2) (pre-Tax Reform Act of 1986, § 168(e)(3)) and former §§ 46(f) and 167(l) ordinarily will not be considered unless the taxpayer states in the letter ruling request whether— (1) the regulatory authority responsible for establishing or approving the taxpayer's rates has reviewed the request and believes that the request is adequate and complete; and (2) the taxpayer will permit the regulatory authority to participate in any Associate office conference concerning the request. If the taxpayer or the regulatory authority informs a consumer advocate of the request for a letter ruling and the advocate wishes to communicate with the Service regarding the request, any such communication should be sent to: Internal Revenue Service, Associate Chief Counsel (Procedure and Administration), Attn: CC:PA:LPD:TSS, P.O. Box 7604, Ben Franklin Station, Washington, DC 20044 (or, if a private delivery service is used: Internal Revenue Service, Associate Chief Counsel (Procedure and Administration), Attn: CC:PA:LPD:TSS, Room 5336, 1111 Constitution Ave., NW, Washington, DC 20224). These communications will be treated as third party contacts for purposes of § 6110.
Unfunded deferred compensation	Rev. Proc. 71-19, 1971-1 C.B. 698, as amplified by Rev. Proc. 92-65, 1992-2 C.B. 428. *See* Rev. Proc. 92-64, 1992-2 C.B. 422, as modified by Notice 2000-56, 2000-2 C.B. 393, for the model trust for use in Rabbi Trust Arrangements.

Safe harbor revenue procedures

.02 For requests relating to the following Code sections and subject matters, refer to the following safe harbor revenue procedures.

CODE OR REGULATION SECTION	*REVENUE PROCEDURE*
23 and 36C Adoption credit for foreign adoptions	Rev. Proc. 2010-31, 2010-40 I.R.B. 413.
103 and 141-150 Issuance of state or local obligations	Rev. Proc. 2017-13, 2017-6 I.R.B. 787 (management contracts); and Rev. Proc. 2007-47, 2007-2 C.B. 108 (research agreements).
61 Utility Cost Recovery Securitization Transactions	Rev. Proc. 2005-62, 2005-2 C.B. 507.
137 Exclusion for Employer Reimbursements	Rev. Proc. 2010-31, 2010-40 I.R.B. 413.
162 Restaurant Small Wares Costs	Rev. Proc. 2002-12, 2002-1 C.B. 374.
165 Losses from corrosive drywall	Rev. Proc. 2010-36, 2010-42 I.R.B. 439.
165 Theft losses from fraudulent investment arrangements	Rev. Proc. 2009-20, 2009-14 I.R.B. 749, as modified by Rev. Proc. 2011-58, 2011-50 I.R.B. 849.
167 and 168 Primary use of certain cable network assets described in asset class 48.42 of Rev. Proc. 87-56, 1987-2 C.B. 674	Section 9 of Rev. Proc. 2015-12, 2015-2 I.R.B. 266.
168 Depreciation of original and replacement tires for certain vehicles	Rev. Proc. 2002-27, 2002-1 C.B. 802.
168 Depreciation of fiber optic node and trunk line of a cable system operator	Section 8 of Rev. Proc. 2015-12, 2015-2 I.R.B. 266.
168 Recovery periods of certain tangible assets used by wireless telecommunication carriers	Rev. Proc. 2011-22, 2011-18 I.R.B. 737
263, 471 Treatment of rotable spare parts as inventory or depreciable property	Rev. Proc. 2007-48, 2007-2 C.B. 110

263 Safe harbor methods for track structure expenditures	Rev. Proc. 2002-65, 2002-2 C.B. 700; Rev. Proc. 2001-46, 2001-2 C.B. 263.
263 Determination whether expenditures to maintain, replace or improve wireline network assets must be capitalized	Rev. Proc. 2011-27, 2011-18 I.R.B. 740.
263 Determination whether expenditures to maintain, replace or improve wireless network assets must be capitalized	Rev. Proc. 2011-28, 2011-18 I.R.B. 743.
263 Allocating success-based fees paid in business acquisitions or reorganizations	Rev. Proc. 2011-29, 2011-18 I.R.B. 746.
263 Electric trade and distribution property assets	Rev. Proc. 2011-43, 2011-37 I.R.B. 326.
263A Safe harbor methods for certain motor vehicle dealerships	Rev. Proc. 2010-44, 2010-49 I.R.B. 811.
280A Safe harbor method to determine the amount of deductible expenses attributable to certain business use of a residence	Rev. Proc. 2013-13, 2013-6 I.R.B. 478.
280B Certain structural modifications to a building not treated as a demolition	Rev. Proc. 95-27, 1995-1 C.B. 704.
446 Film producer's treatment of certain creative property costs	Rev. Proc. 2004-36, 2004-1 C.B. 1063.
446 Bank's treatment of uncollected interest	Rev. Proc. 2007-33, 2007-1 C.B. 1289.
448 Nonaccrual-experience method - book safe harbor method	Rev. Proc. 2011-46, 2011-42 I.R.B. 518.
451 Safe harbor for capital cost reduction payments	Rev. Proc. 2002-36, 2002-1 C.B. 993.

451 Treatment of gift cards issued to customers in exchange for returned merchandise	Rev. Proc. 2011-17, 2011-5 I.R.B. 441.
451 Safe harbor for certain minors' trusts established under the Indian Gaming Regulatory Act (U.S.C. §§ 2701-2721)	Rev. Proc. 2011-56, 2011-49 I.R.B. 834.
461 Safe harbor method for payroll tax liabilities for compensation	Rev. Proc. 2008-25, 2008-1 C.B. 686.
471 Estimating inventory shrinkage	Rev. Proc. 98-29, 1998-1 C.B. 857.
471 Valuation of automobile dealer vehicle parts inventory	Rev. Proc. 2002-17, 2002-1 C.B. 676.
471 Valuation of remanufactured cores	Rev. Proc. 2003-20, 2003-1 C.B. 445.
471 Valuation of heavy equipment dealer parts inventory	Rev. Proc. 2006-14, 2006-1 C.B. 350.
471 Rolling-average method of accounting for inventories	Rev. Proc. 2008-43, 2008-2 C.B. 186.
475 Eligible positions	Rev. Proc. 2007-41, 2007-1 C.B. 1492.
584(a) Qualification of a proposed common trust fund plan	Rev. Proc. 92-51, 1992-1 C.B. 988.
642(c)(5) Qualification of trusts as pooled income funds	Rev. Proc. 88-53, 1988-2 C.B. 712.
664 Charitable remainder trusts	Rev. Proc. 2005-24, 2005-1 C.B. 909, as modified by Notice 2006-15, 2006-1 C.B. 501.
664(d)(1) Qualification of trusts as charitable remainder annuity trusts	Rev. Proc. 2003-53, 2003-2 C.B. 230; Rev. Proc. 2003-54, 2003-2 C.B. 236; Rev. Proc. 2003-55, 2003-2 C.B. 242; Rev. Proc. 2003-56, 2003-2 C.B. 249; Rev. Proc. 2003-57, 2003-2 C.B. 257; Rev. Proc. 2003-58, 2003-2 C.B. 262; Rev. Proc. 2003-59, 2003-2 C.B. 268; Rev. Proc. 2003-60, 2003-2 C.B. 274.
664(d)(2) and (3) Qualification of trusts as charitable remainder unitrusts	Rev. Proc. 2005-52, 2005-2 C.B. 326; Rev. Proc. 2005-53, 2005-2 C.B. 339; Rev. Proc. 2005-54, 2005-2 C.B. 353; Rev. Proc. 2005-55, 2005-2 C.B. 367; Rev. Proc. 2005-56, 2005-2 C.B. 383; Rev. Proc. 2005-57, 2005-2 C.B. 392; Rev. Proc. 2005-58, 2005-2 C.B. 402; Rev. Proc. 2005-59, 2005-2 C.B. 412.

832 Insurance company premium acquisition expenses	Rev. Proc. 2002-46, 2002-2 C.B. 105.
856(c) Certain loans treated as real estate assets	Rev. Proc. 2003-65, 2003-2 C.B. 336.
1031(a) Qualification as a qualified exchange accommodation arrangement	Rev. Proc. 2000-37, 2000-2 C.B. 308, as modified by Rev. Proc. 2004-51, 2004-2 C.B. 294.
1031 Safe harbor with respect to exchanges of residential real property	Rev. Proc. 2008-16, 2008-1 C.B. 547.
1031 Safe harbor for reporting gain or loss on failed exchanges	Rev. Proc. 2010-14, 2010-12 I.R.B. 456.
1272(a)(6) Proportional method of accounting for original issue discount on pools of credit card receivables	Rev. Proc. 2013-26, 2013-22 I.R.B. 1160.
1286 Determination of reasonable compensation under mortgage servicing contracts	Rev. Proc. 91-50, 1991-2 C.B. 778.
1362(f) Automatic inadvertent termination relief to certain corporations	Rev. Proc. 2013-30, 2013-36 I.R.B. 173.
2056A Qualified Domestic Trust	Rev. Proc. 96-54, 1996-2 C.B. 386.
2702(a)(3)(A) and 25.2702-5(c) Qualified Personal Residence Trust	Rev. Proc. 2003-42, 2003-1 C.B. 993.
4051(a)(2) Imposition of tax on heavy trucks and trailers sold at retail	Rev. Proc. 2005-19, 2005-1 C.B. 832.
1.7704-2(d) New business activity of existing partnership is closely related to pre-existing business	Rev. Proc. 92-101, 1992-2 C.B. 579.
SUBJECT MATTERS	*REVENUE PROCEDURE*
Certain rent-to-own contracts treated as leases	Rev. Proc. 95-38, 1995-2 C.B. 397.

Automatic change in accounting period revenue procedures

.03 For requests for an automatic change in accounting period, refer to the following automatic change revenue procedures.

Rev. Proc. 2006-45, 2006-2 C.B. 851, as clarified and modified by Rev. Proc. 2007-64, 2007-2 C.B. 818 (certain corporations); Rev. Proc. 2006-46, 2006-2 C.B. 859 (certain partnerships, subchapter S corporations, personal service corporations, and trusts); and Rev. Proc. 2003-62, 2003-2 C.B. 299 (individuals seeking a calendar year).

The Commissioner's consent to an otherwise qualifying automatic change in accounting period is granted only if the taxpayer timely complies with the applicable automatic change revenue procedure.

INDIANA MICHIGAN POWER COMPANY

SCHEDULE OF TARIFFS AND TERMS AND
CONDITIONS OF SERVICE
GOVERNING
SALE OF ELECTRICITY
IN THE STATE OF INDIANA

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 2**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

LOCALITIES WHERE ELECTRIC SERVICE IS AVAILABLE

LOCALITY	COUNTY
Aboite Township	Allen
Adams Township	Allen
Albany	Randolph
Albion	Noble
Albion Township	Noble
Alexandria	Madison
Allen Township	Noble
Anderson Township	LaPorte
Baugo Township	Elkhart
Bear Creek Township	Jay
Bear Creek Township	Adams
Benton Township	Elkhart
Berne	Adams
Blountsville	Henry
Blue Creek Township	Adams
Boone Township	Madison
Bryant	Jay
Bryant Township	Wells
Butler	DeKalb
Butler Township	DeKalb
Cedar Creek Township	Allen
Center Township	Delaware
Center Township	Grant
Center Township	LaPorte
Center Township	Marshall
Centre Township	St. Joseph
Chester Township	Wells
Chesterfield	Madison
Churubusco	Whitley
Clay Township	St. Joseph
Clear Creek	Huntington
Cleveland Township	Elkhart
Cleveland Township	Whitley
Cool Spring Township	LaPorte
Columbia Township	Whitley
Concord Township	DeKalb
Concord Township	Elkhart
Decatur	Adams
Delaware Township	Delaware
Dunkirk	Jay
	Blackford
Duck Creek Township	Madison
Eaton	Delaware
Eel River Township	Allen
Elkhart	Elkhart
Elwood	Madison
Fall Creek Township	Henry
Fairfield Township	DeKalb
Fairmount	Grant
Farmland	Randolph
Fort Wayne	Allen
Fowlerton	Grant
Franklin Township	DeKalb
Franklin Township	Grant
Franklin Township	Randolph
French Township	Adams
Galena Township	LaPorte
Gas City	Grant
Gaston	Delaware
Geneva	Adams
German Township	St. Joseph
Grabill	Allen
Grant Township	DeKalb
Green Township	Noble
Green Township	Randolph
Greene Township	Grant
Greene Township	Jay
Greene Township	St. Joseph
Greens Fork Township	Randolph
Hamilton	DeKalb
Hamilton Township	Steuben
Hamilton Township	Delaware
Harris Township	St. Joseph
Harrison Township	Blackford

(Cont'd on Sheet No. 2.1)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 2.1**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

LOCALITIES WHERE ELECTRIC SERVICE IS AVAILABLE

(Cont'd from Sheet No. 2)

LOCALITY	COUNTY	LOCALITY	COUNTY
Harrison Township	Delaware	Lakeville	St. Joseph
Harrison Township	Wells	Lancaster Township	Huntington
Harrison Township	Elkhart	Lancaster Township	Wells
Hartford Township	Adams	LaPaz	Marshall
Hartford City	Blackford	Liberty Township	Delaware
Hudson Township	LaPorte	Liberty Township	Grant
Huntertown	Allen	Liberty Township	St. Joseph
		Liberty Township	Wabash
Indian Village	St. Joseph	Liberty Township	Wells
		Licking Township	Blackford
Jackson Township	Blackford	Ligonier	Noble
Jackson Township	Howard	Lincoln Township	LaPorte
Jackson Township	Madison	Losantville	Randolph
Jackson Township	Miami	Lynn	Randolph
Jackson Township	Jay		
Jackson Township	Randolph	Madison Township	Allen
Jackson Township	Wells	Madison Township	Jay
Jackson Township	DeKalb	Madison Township	St. Joseph
Jackson Township	Huntington	Madison Township	Tipton
Jefferson Township	Grant	Marion Township	Allen
Jefferson Township	Huntington	Marion	Grant
Jefferson Township	Jay	Matthews	Grant
Jefferson Township	Adams	Maumee Township	Allen
Jefferson Township	Allen	Michigan Township	LaPorte
Jefferson Township	Henry	Milan Township	Allen
Jefferson Township	Elkhart	Mill Township	Grant
Jefferson Township	Noble	Mishawaka	St. Joseph
Jefferson Township	Wells	Modoc	Randolph
Jefferson Township	Whitley	Monroe Township	Adams
Jonesboro	Grant	Monroe	Adams
		Monroe Township	Allen
Kankakee Township	LaPorte	Monroe Township	Delaware
Kendallville	Noble	Monroe Township	Grant
Keyser Township	DeKalb	Monroe Township	Madison
Kirkland Township	Adams	Monroe Township	Randolph
Knox Township	Jay	Monroeville	Allen
		Montpelier	Blackford
Lafayette Township	Allen	Mt. Etna	Huntington
Lafayette Township	Madison	Mt. Pleasant	Delaware
Lake Township	Allen	Muncie	Delaware

(Cont'd on Sheet No. 2.2)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 2.2**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

LOCALITIES WHERE ELECTRIC SERVICE IS AVAILABLE

(Cont'd from Sheet No. 2.1)

LOCALITY	COUNTY	LOCALITY	COUNTY
New Carlisle	St. Joseph	Roanoke	Huntington
New Haven	Allen	Rock Creek Township	Huntington
Newville Township	DeKalb	Rock Creek Township	Wells
Niles Township	Delaware	Root Township	Adams
Noble Township	Jay	Roseland	St. Joseph
Noble Township	Noble	Redkey	Jay
North Township	Marshall		
Nottingham Township	Wells	Salamonia	Jay
		Salamonia Township	Huntington
Olive Township	Elkhart	Salem Township	Delaware
Olive Township	St. Joseph	Saratoga	Randolph
Orestes	Madison	Scipio Township	Allen
Osceolo	St. Joseph	Scott Township	Steuben
Osolo	Elkhart	Selma	Delaware
Ossian	Wells	Shamrock Lakes	Blackford
Otsego Township	Steuben	Sims Township	Grant
		South Bend	St. Joseph
Parker	Randolph	Smith Township	Whitley
Penn Township	Jay	Smithfield Township	DeKalb
Penn Township	St. Joseph	Sparta Township	Noble
Pennville	Jay	Spencer Township	DeKalb
Perry Township	Allen	Springfield Township	Allen
Perry Township	Delaware	Springfield Township	LaPorte
Perry Township	Noble	Stafford Township	DeKalb
Pike Township	Jay	St. Joe Township	Allen
Pipe Creek Township	Madison	St. Marys Township	Adams
Pleasant Township	Allen	Stony Creek Township	Henry
Pleasant Township	Grant	Stony Creek Township	Madison
Polk Township	Huntington	Stony Creek Township	Randolph
Poneto	Wells	Summitville	Madison
Portage Township	St. Joseph	Swan Township	Noble
Preble Township	Adams	Swayzee	Grant
Portland	Jay	Sweetser	Grant
Richland Township	Grant	Thorncreek Township	Whitley
Richland Township	Jay	Troy Township	DeKalb
Richland Township	Madison		
Richland Township	Steuben	Union Township	Adams
Richland Township	Whitley	Union Township	Delaware
Ridgeville	Randolph	Union Township	DeKalb

(Cont'd on Sheet No. 2.3)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

LOCALITIES WHERE ELECTRIC SERVICE IS AVAILABLE

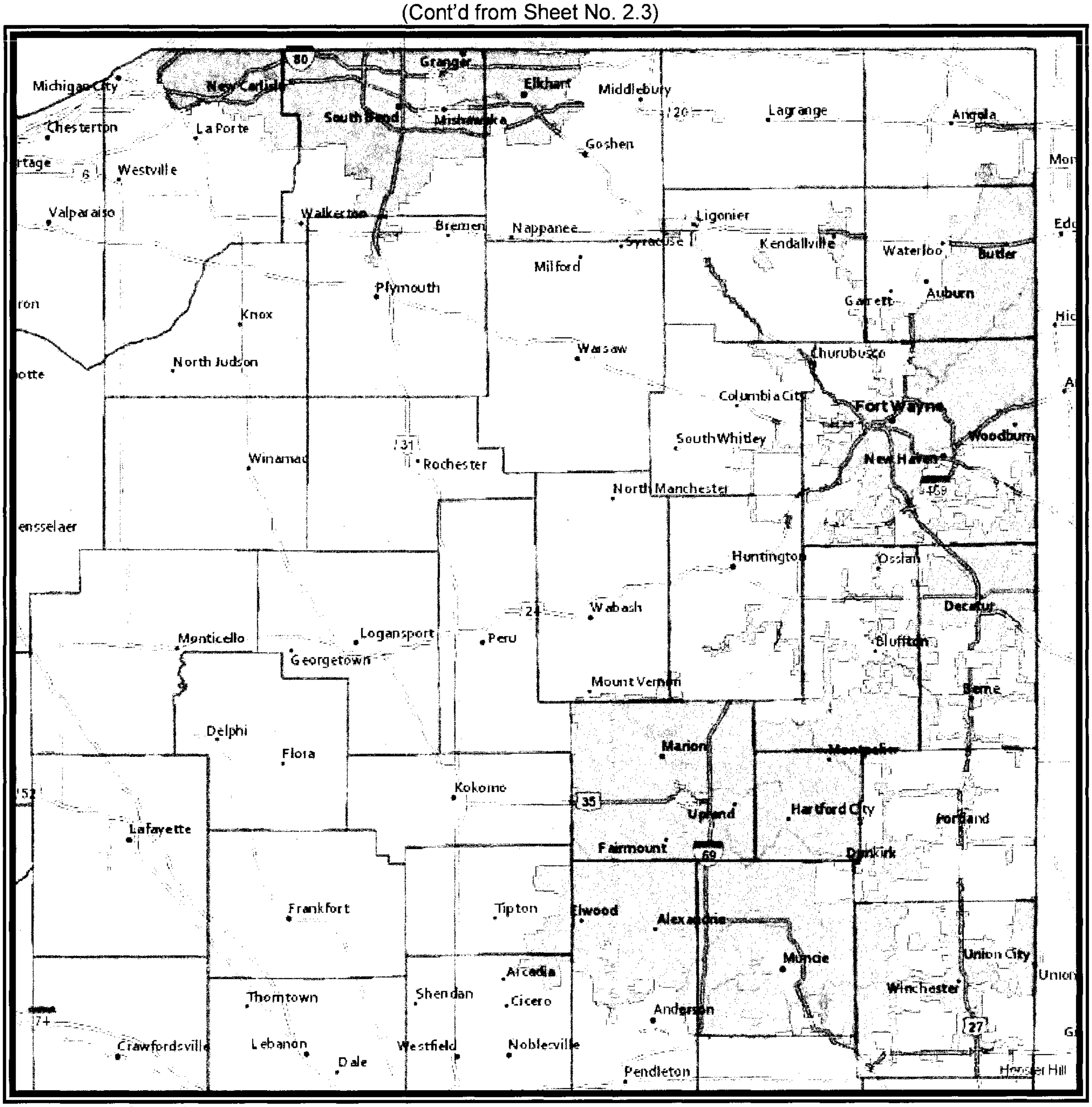
(Cont'd from Sheet No. 2.2)

LOCALITY	COUNTY	LOCALITY	COUNTY
Union Township	Hamilton	York Township	Noble
Union Township	Howard	York Township	Steuben
Union Township	Madison	Yorktown	Delaware
Union Township	Randolph		
Union Township	St. Joseph		
Union Township	Wells		
Union Township	Whitley		
Union City	Randolph		
Uniondale	Wells		
Upland	Grant		
Van Buren	Grant		
Van Buren Township	Madison & Grant		
Vera Cruz	Wells		
Wabash Township	Adams		
Wabash Township	Jay		
Waltz Township	Wabash		
Ward Township	Randolph		
Warren Township	St. Joseph		
Washington Township	Adams		
Washington Township	Allen		
Washington Township	Blackford		
Washington Township	Delaware		
Washington Township	Elkhart		
Washington Township	Grant		
Washington Township	Whitley		
Wayne Township	Allen		
Wayne Township	Huntington		
Wayne Township	Jay		
Wayne Township	Noble		
Wayne Township	Randolph		
White River	Hamilton		
White River Township	Randolph		
Wildcat	Tipton		
Wills Township	LaPorte		
Wilmington Township	DeKalb		
Winchester	Randolph		
Woodburn	Allen		

(Cont'd on Sheet No. 2.4)

AREA MAP OF LOCALITIES WHERE ELECTRIC SERVICE IS AVAILABLE

(Cont'd from Sheet No. 2.3)



Source: IURC Website - August 2016

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ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

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I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 2.6**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

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I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 2.7**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

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ABBREVIATIONS, TECHNICAL TERMS AND DEFINITIONS

ABBREVIATIONS

IURC – Indiana Utility Regulatory Commission

I&M – Indiana Michigan Power Company

kVA – Kilovolt-ampere(s)

kW – Kilowatt(s)

kWh – Kilowatt-hour(s)

PJM – PJM Interconnection, LLC

RKVAH – Reactive Kilovolt-ampere(s) Hour

UG – Underground

TECHNICAL TERMS AND DEFINITIONS

"Applicant" – Any person, firm, corporation, municipality or other government agency which has applied for a new rate schedule with 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 or kVA (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.

"Cogeneration Facility" – A facility that simultaneously generates electricity and useful thermal energy and meets the energy efficiency standards established for a cogeneration facility by the Federal Energy Regulatory Commission (FERC) under 16 U.S.C. 824a-3, in effect November 9, 1978.

"Commercial and industrial customers" – any customer not classified as residential.

"Commission" – means the Indiana Utility Regulatory 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 or kVA for which Customer contracts and Company is obligated to supply.

(Cont'd on Sheet No. 2.9)

(Cont'd from Sheet No. 2.8)

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

"Customer" – Any person, firm, corporation, municipality or other government agency which has agreed, orally or otherwise, to pay for electric service from the Company.

"Customer in Good Standing" – Unless specifically stated, a customer is considered to be in good standing unless they have been issued disconnect notices for 2 consecutive months or any 3 months within the preceding 12-month period, or had service involuntarily disconnected for any reason other than safety during that same period.

"Delinquent Bill" – A Customer Bill that has remained unpaid for the period set forth in the IURC Rules (170 IAC 4-1-13).

"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 or kVA, 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.

"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.

"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.

(Cont'd on Sheet No. 2.10)

(Cont'd from Sheet No. 2.9)

"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.

"Other Sources of Energy Supply" – shall mean "other sources of electric energy supply" except where the Company provides service as standby or partial standby for a source of energy other than electric energy.

"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.

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

"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.

"Remote Disconnection or Restoration Capability" – the ability to terminate or restore service to a premise from another location.

"Residential Customer" – a customer receiving service for a dwelling unit, defined as one or more rooms including kitchen in a building 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 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 services from the Company under a Commission approved rate schedule.

(Cont'd on Sheet No. 2.11)

(Cont'd from Sheet No. 2.10)

"Subtransmission Voltage" – typically 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.

TERMS AND CONDITIONS OF SERVICE

1. Tariffs, Terms and Conditions of Service.

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

A copy of all Tariffs and Terms and Conditions of Service is on file with the Indiana Utility Regulatory 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, as specified by tariff or contract, upon written application to the Company. A customer may not change from one tariff to another in less than 12 months or during the term of contract except with the consent of 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.

2. Application.

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.

When the customer desires delivery of energy at more than one point, a separate agreement may be required for each separate point of delivery. Service delivered at each point of delivery will be billed separately under the applicable tariff.

3. Bills for Electric Service.

Bills for electric service will be rendered monthly at intervals of approximately 30 days in accordance with the tariff applicable to the customer's service and must be paid for in U.S. Dollars.

All bills are rendered as "net" bills which will be subject to a late payment charge if not paid within 17 days after the bill is mailed; provided, however, that 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. The late payment charge to be added to bills of $3 or less shall be 10 percent of the amount of the bill, and to bills in excess of $3, the amount to be added to the bill shall be 10 percent of the first $3 plus 3 percent of the amount of the bill in excess of $3.

(Cont'd on Sheet No. 3.1)

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3)

A customer shall be charged $20 for any dishonored, negotiable instrument received in payment for a bill rendered by the Company, unless the customer shows that the financial institution was in error.

Failure to receive a bill shall not entitle the customer to pay the net bill after the designated payment date has passed. 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.

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. 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, the customer will be charged or credited for such period on an estimated consumption based upon his use of energy in a similar period of like use. This estimation shall include adjustments for changes in customer's load during the period the meter was not registering properly. All such billing errors will be adjusted to the known date of error or for a period of one year, whichever is shorter.

Residential customers using electric service shall have the option of paying bills under the Company's Average Monthly Payment Plan (AMPP). Residential customers enrolled under the Company's Equal Payment Plan (EPP) as of February 28, 2013 shall have the option of continuing under the EPP. Both of the Company's budget billing plans, AMPP and EPP are described below.

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, the amount of such over payment shall, at the option of the Company, be either refunded or credited to the customer at the end of the period.

(Cont'd on Sheet No 3.2)

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.1)

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 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.

(Cont'd on Sheet No. 3.3)

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.2)

4. ~~Flex Pay Program~~

~~Availability of Service~~

~~This payment option is available on a voluntary basis to all residential customers who have an Advanced Metering Infrastructure (AMI) meter rated up to 200 amps installed at their residence. The Flex Pay option is not available to customers with medical, life threatening, or life support conditions; customers having on-site generation operated in parallel with the Company's system; or customers on Tariff EZB, the Average Monthly Payment (AMP) plan or Equal Payment Plan (Budget). This option is not available to customers without a valid and operable electronic communication method (*i.e.*, text messaging or electronic mail). The Flex Pay option is also not available to any customer scheduled for a disconnection of service for nonpayment and who has initiated the process for enrollment in this payment option two or more times within a thirty (30) day period without completing all of the requirements for enrollment.~~

~~Program Description.~~

~~I&M's Flex Pay Program, is a voluntary payment option that allows customers to prepay for electric service.~~

~~**Terms and Conditions of Service**~~

~~Service under the Flex Pay Program will be offered to customers under the customer's otherwise applicable standard residential rate schedule. Billing will be based on a customer's actual daily usage, the effective base rate, and all applicable riders and fees. Fixed charges will be applied to the account on a daily basis based on 1/30 of the total fixed charges and will be subtracted daily from the customer's Flex Pay account balance.~~

~~To enroll in the Flex Pay Program, a customer must make an initial payment of at least $40.00. Any deposit that an existing customer has previously paid to the Company will be applied to the customer's current account balance, with the remaining credit/debit balance from the customer's existing account, if any, transferred to the customer's Flex Pay account balance. A customer with an outstanding current balance or final account balance from a previous account may carry-over up to $1,500 of the account balance to their Flex Pay account balance to be paid off through the Flex Pay Program. Any payments to the Flex Pay account will first have a 20% portion of the payment applied to the arrears balance, with the remaining portion of the payment credited to the customer's Flex Pay account until the arrears balance is fully paid.~~

~~The customer is responsible for monitoring usage under this program and ensuring that the account balance is sufficient to continue electric service. The customer must maintain an account balance greater than zero, not including any arrears amount carried over from another account, to continue electric service under this program. The customer will be notified when the account reaches the customer selected low balance amount or the amount of $25.00, whichever is greater. Notification will occur through the customer's selected form of communication, including email, and/or text message. A customer web portal will be available to view the customer's usage information.~~

(Cont'd on Sheet No. 3.4)

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 3.4**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.3)

~~Should a customer's balance reach zero, the customer will be notified via the customer's chosen communication method. The customer will have until the beginning of the next business day to re-establish a positive balance or the customer's meter will automatically be disconnected during normal business hours regardless of weather or temperature as the customer is responsible for ensuring that the Flex Pay account is adequately funded. Normal business hours are 8:00 a.m. to 3:00 p.m. ET, Monday through Friday, excluding Company observed holidays and moratoriums. Customers will be required to pay in full any accrued balance for usage during weekends, holidays and moratoriums before service will be restored. Once the customer's payment is received and accepted, and the customer's Flex Pay account balance is greater than zero, service will be restored by the Company in a timely manner.~~

~~Financial assistance received for a Flex Pay account will be credited to the balance of the Flex Pay account upon receipt of the funds.~~

~~Customers requesting a $10 Financial Hardship Reconnect, enrollment in Life Support Program or a Medical Certificate will be removed from the Flex Pay Program and placed on the tariff that is otherwise applicable to the customer's service.~~

~~No deposit, reconnect, or late fee charges shall be assessed to customers enrolled in the Flex Pay Program.~~

~~When the Company receives a dishonored negotiable instrument (i.e. returned check), any account credits associated with that instrument will be removed from the customer's account. If the removal of the credits results in the customer's balance reaching zero, the customer will be notified and will have until the beginning of the next business day to reestablish a positive balance or the customer's meter will automatically be disconnected during normal business hours.~~

~~Actual billing will continue to be based upon the applicable rate and meter readings obtained to determine consumption. Flex Pay customers are required to participate in and receive their information through the Company's paperless billing program. Customers will continue to receive an online monthly statement summary containing all of the charges, usage and payments applied during their normal 30-day billing cycle.~~

~~Customer accounts must be funded through a Company authorized payment channel, including immediate payment via telephone or website using electronic check, debit or credit cards, or any in-person pay station. Each authorized payment method is subject to Company guidelines. Timing of payments to accounts cannot be guaranteed if payment is made through an unauthorized pay agent or by mail.~~

~~The customer may cancel service under this payment option at any time and will be returned to the applicable traditional post-pay billing option in accordance with I&M's approved tariffs.~~

(Cont'd on Sheet No. 3.5)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

TERMS AND CONDITIONS OF SERVICE
(Cont'd from Sheet No. 3.4)

~~Account settlement shall occur when participation in the plan is terminated. Termination occurs when an account is final billed or if the customer requests termination. If the account terminates off-cycle during the billing period, the remaining monthly fixed charges and fees that have not yet been collected will be applied to the final bill. After settlement of the Flex Pay account, any remaining unused balance will be transferred to the customer's other active account(s), if any. If the customer does not have any other active accounts the Company shall refund the remaining unused balance by one of the following means: a prepaid card, a check or electronic funds transfer (EFT).~~

4~~5~~. Deposits - Residential

A new applicant for residential service shall not be required to make a cash deposit as a condition of receiving service if the applicant satisfies the following criteria:

(a) Applicant (i) has been a customer of any utility within the last two years, (ii) owes no outstanding bills for service rendered by any such utility, (iii) did not have, during the last 12 consecutive months that the service was provided, more than two bills which were delinquent to any utility or, if service has been rendered for a period for less than 12 months, has not had more than one delinquent bill in such period, and (iv) within the last 2 years did not have a service disconnected by a utility for nonpayment of a bill for services rendered by that utility.

(b) If applicant has not been a customer of a utility during the previous two years and any two of the following three criteria are met:

i. Either applicant (a) has been employed by his present employer for two years, or (b) has been employed by his present employer for less than two years but has been employed by only one other employer during the past two years, or (c) has been employed by the present employer for less than two years and has no previous employment due to having recently graduated from a school, university, vocational program, or has recently been discharged from military service.

ii. Applicant either (a) owns or is buying his or her home or (b) is renting a home or an apartment and has occupied the premises for more than two years.

iii. Applicant has credit cards, charge accounts, or has been extended credit by a bank, commercial concern, or individual; unless a credit check shows that the applicant has been in default on any such account more than twice within the last 12 months.

(c) If an applicant or current customer is a LIHEAP participant or is LIHEAP eligible, the deposit amount will be limited to $50.00.

(Cont'd on Sheet No. 3.6)

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.5)

If the Company denies service or requires a cash deposit as a condition of providing service, then it must immediately send a written notice to the applicant stating the precise facts upon which it bases its decision and provide the applicant with an opportunity to rebut such facts and show other facts demonstrating his creditworthiness.

The Company may require a cash deposit from an existing customer when the customer has been mailed disconnect notices for 2 consecutive months or any 3 months within the preceding 12-month period, or when the service has been disconnected pursuant to the rules for nonpayment.

The amount of such deposit may not exceed an amount equal to one-sixth of the expected annual billings for the customer at the address at which service is rendered. Deposits required under the rules for nonpayment in amounts less than or equal to $70, shall be paid in full prior to restoration of service. If the deposit required under the rules for nonpayment exceeds $70, a minimum of $70 shall be required prior to restoration of service. The remaining amount of the required deposit will be split equally between the next two (2) monthly billing cycles (approximately 60 days). Deposits shall earn interest as follows:

(1) When the deposit is refunded within 12 months from the date of deposit, no interest is payable.

(2) Deposits held more than 12 months shall earn interest from the date of deposit to the date of refund at an annual interest rate of 2%.

(3) The deposit shall not earn interest after the date it is mailed, personally delivered to the customer, or otherwise lawfully disposed of.

Any deposit and/or accrued interest shall be refunded upon satisfactory payment by a residential customer for a period of either 9 successive months or 10 out of any 12 consecutive months (provided that the customer did not make late payment for any 2 consecutive months) or upon the customer demonstrating his creditworthiness by any other means. Refund of deposits and/or accrued interest on accounts that are disconnected for nonpayment will occur within 60 days if all outstanding balances have been resolved. Deposits and/or accrued interest will be refunded following customer-requested termination of service.

Company may refund such deposits by applying the deposit and/or accrued interest to the bill, and such application shall constitute a lawful disposition of such deposits. Upon specific request from the customer, the utility shall refund the deposit and/or accrued interest within 15 days after payment of the final bill. A deposit may be used by the utility to cover any unpaid balance following disconnection of service pursuant to Rule 5; provided, however, that any surplus be returned to the customer as provided above.

(Cont'd on Sheet No. 3.7)

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 3.7

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.6)

Nonresidential

The Company shall determine the creditworthiness of new and existing nonresidential customers in an equitable and nondiscriminatory manner.

A new or existing nonresidential customer will be deemed non-creditworthy if either (a) it has three delinquent payments, two consecutive delinquent payments, or been disconnected for nonpayment within the last 24 months; or (b) its credit rating is B+ or below for S&P or B1 or below for Moody's

For the purposes of this rule, a new customer does not include a customer who changes its corporate name or corporate structure, or an existing customer who establishes a new account.

The Company may require a deposit from a non-creditworthy customer as a condition of providing or continuing to provide service.

In the event that the Company requires a deposit as a condition of providing or continuing to provide service, then the Company must: (a) provide notice to the new or existing customer stating the precise facts upon which the Company based its decision, (b) provide the new or existing customer with an opportunity to rebut the Company's decision including, but not limited to, the presentation of information such as payment history to other utilities and verifiable data such as independently audited financial statements, analyses of leverage, liquidity, profitability, cash flow and other credit related information: and (c) monitor the customer's account annually (or upon customer request), for deposit requirements validating customer's creditworthiness with prompt repayment upon customer request once the customer meets the criteria for creditworthiness set forth in this rule. This provision, including the right to contest the need for a deposit, is without prejudice to the customer's right to challenge the deposit requirements before the Indiana Utility Regulatory Commission

Any deposit demanded under this rule will be equal to no more than 1/6th the annual billing for a current customer or 1/6th expected annual billings of a new customer The Company shall not aggregate customer accounts for purposes of calculating a deposit, but shall instead calculate a deposit based only on annual billings of an existing customer's delinquent account.

Deposits may be paid in cash, through the provision of a Surety Bond or Irrevocable Letter of Credit, through another method of security approved by the Company or in three (3) equal monthly payments unless the customer is delinquent, in which case the full deposit is due.

Deposits shall earn interest as follows:

(1) Deposits held more than twelve (12) months shall earn interest from date of deposit to the date of refund at an annual interest rate to be determined by the Indiana Utility Regulatory Commission. Current approved rate is 2% annually.

(2) The deposit shall not earn interest after the date it is mailed, personally delivered to the customer, or otherwise lawfully disposed of.

(Cont'd on Sheet No. 3.8)

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 3.8**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.7)

In addition to refunds upon the annual review of a customer's creditworthiness by the Company, deposits will be refunded:

(1) Upon the customer's written request, made not more than once a year, and upon establishment of creditworthiness as defined above: or

(2) Within sixty (60) days following termination of service with the deposit applied to any delinquent bills and the remainder paid to the customer.

In the event a customer disputes a portion of a bill in writing to I&M, provided the customer pays all undisputed portions before the bill is delinquent as defined above, the bill shall not be considered delinquent. I&M will promptly review the dispute, and the disputed portion of the bill will not be considered delinquent while the bill remains subject to review (including any complaint process initiated at the Indiana Utility Regulatory Commission).

For customer who have made arrangements with the I&M for electronic billing, the date the bill will be considered delinquent shall be calculated from the date of electronic transmission of the bill, or such other date as agreed to by the Company and the customer.

I&M shall be able to decline imposition of a deposit that may otherwise be required under this rule based on the individual circumstances of the customer.

5~~6~~. Denial or Discontinuance of Service.

General

The Company reserves the right after at least 14 days' notice in writing to discontinue to serve any customer (1) who is indebted to the Company for any service theretofore rendered at any location (on other than equal payment plan accounts having a credit balance), (2) for failure to provide and maintain adequate security for the payment of bills as requested by the Company, or (3) for failure to comply with these Terms and Conditions. The Company also reserves the right to refuse electric service to any applicant if the applicant is indebted to the Company for any charge theretofore rendered at any location, provided Company shall advise applicant to such effect.

(Cont'd on Sheet No. 3.9)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.8)

Any discontinuance of service shall be in accordance with rule IAC 4-1-16 including a visit to the premise to notify the customer of pending disconnection of service. This would not apply to customers that have an AMI meter with remote functionality in which a waiver to these rules has been approved or the customer has threatened to or has caused endangerment to an employee's personal safety. In which case such visit to the premise will be replaced by a phone call notification and remote disconnection / reconnection will be utilized where applicable. The Company will not remotely disconnect a customer who has demonstrated a safety risk to Company personnel and is otherwise subject to disconnection if the temperature is forecasted to be below 25 degrees or above 95 degrees during the following 24 hour period. Examples of activities that threaten or cause endangerment to employees' personal safety include, but are not limited to:

- Verbal and physical abuse;
- Use of vicious animals;
- Brandishing or referencing use of weapons; and
- Purposefully creating unsafe working environment on premise

Disconnection of service shall not terminate the contract between the Company and the customer nor shall it abrogate any minimum service charge or other monthly charge as specified in the applicable tariff.

The customer shall notify the Company at least three days in advance of the day disconnection is desired. The customer shall remain responsible for all service used and the billings therefore until service is disconnected pursuant to such notice.

Upon request by a customer to disconnect service, the Company shall disconnect the service within three working days following the required disconnection date. The customer shall not be liable for any service rendered to such address or location after the expiration of three such days.

(Cont'd on Sheet No. 3.10)

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.9)

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.

(Cont'd on Sheet No. 3.11)

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 3.11**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.10)

6~~7~~. Service, Reconnect and Trip Charges.

In cases where the Company has discontinued service for nonpayment of bills, customer convenience and/or other causes stipulated herein, the right is reserved to charge the customer an amount in accordance with the following schedule of charges. The Company will endeavor to comply with customer requested work subject to a minimum of three business days' prior notification and/or manpower availability.

SCHEDULE OF CHARGES	AMOUNT
1. AMI Opt-Out Customers - Reconnect during regular business hours.	$83
2. AMI Opt-Out Customers - Reconnect during workday overtime hours and all day Saturday.	$93
3. AMI Opt-Out Customers - Reconnect on Sundays or holidays.	$177
4. AMI Opt-Out Customers - Trip Charge where Company employees are sent to customer premises to specifically notify the customer that bill payment is due or disconnection for non-pay is scheduled but not performed due to access, field promise or other related issue at customer site.	$41
5. Reconnect when disconnect is required to be made from a vault, manhole, or service box in a confined space.	$1341
6. Reconnect during regular business hours when disconnect is required to be made at pole.	$119
7. Reconnect during workday overtime hours and all day Saturday when disconnect is required to be made at pole.	$132
8. Reconnect on Sunday or holidays when disconnect is required to be made at pole.	$245
9. Trip Charge for No-power service call when the customer's facilities are clearly at fault or in cases where a Company employee is sent to the customer premises for scheduled work and the customer is not ready and the customer was advised of the charge.	$41
10. Meter test or change when charge is permitted in accordance with the provision of Item No. 21 of the Terms and Conditions of Service.	$84

(Cont'd on Sheet No. 3.12)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

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IN CAUSE NO. 45576

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 3.12

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.11)

7~~8~~. 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, the cost of equipment to safely secure metering and other Company equipment, a $50 tampering fee and the cost of making repairs necessitated by such use and/or tampering. In any event, the Company may make a charge for such out-of-pocket costs, but in no case will the total charge for tampering be less than $100. Under such circumstances, the Company may disconnect service without notice, and the Company is not required to reconnect the service until a deposit and all of the aforementioned enumerated charges are paid in full and all hazards are repaired and inspected (subject to any provision of Commission Rule 16 to the contrary).

8~~9~~. 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.

Where a customer's premises are located in an area not governed by local inspection laws or ordinances, wiring shall be installed in accordance with the requirements of the National Electrical Code. Before furnishing service, Company may require a certificate or notice of approval from a duly-recognized authority stating that customer's wiring has been installed in accordance with the requirements of the National Electrical Code.

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

(Cont'd on Sheet No. 3.13)

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.12)

9~~10~~. Service Connections.

The Company will, when requested to furnish service, designate the location of its service connection.

At the Company's discretion, loads greater than 2500 kVA may be served by more than one transformer set in parallel and adjacent, and therefore by more than one set of metering. Where energy is delivered in this manner, the monthly billing demand will be calculated as if the customer is served by a single delivery point.

A customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the 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 these Terms and Conditions of Service.

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.

All customer's 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 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.

(Cont'd on Sheet No. 3.14)

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 3.14

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.13)

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 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 exterior building wall to the meter location; however, all right and title to the cable shall remain with the Company.

10~~11~~. 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.

11~~12~~. 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 when the Company has carried on a program of maintenance consistent with the general practices prevailing in the industry. 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 a predetermined plan and only in situations that threaten massive curtailments of service on the Company's system. Notwithstanding any other provisions of the terms of these Tariffs and Terms and Conditions of Service, the Company may shut off service temporarily for reasons of health, safety, maintenance of Company facilities, infrastructure improvements, and new construction of Company facilities. To the extent possible, the Company will make a reasonable attempt to inform all affected customers in advance of such events.

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 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.

(Cont'd on Sheet No. 3.15)

ISSUED BY
STEVEN F. BAKER
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FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

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IN CAUSE NO. 45576

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.14)

The customer shall provide and maintain suitable protective devices on customer-owned 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 fluctuations or irregularity in the supply of energy which could have been prevented by the use of such protective devices.

The Company will provide and maintain the necessary line or service connections, transformers (when same are required by conditions of contract between the parties thereto), meters, and other apparatus which 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.

12~~13~~. 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 employees or agents of the Company shall make any internal or external adjustment to or shall otherwise interfere with or break the seals of meters or other equipment of the Company installed on the customer's premises.

The Company shall have the right at all reasonable hours to enter 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 the termination of the 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.

The customer shall provide and maintain suitable protective devices on customer-owned 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 fluctuations or irregularity in the supply of energy which could have been prevented by the use of such protective devices. The Company may disconnect service without request by the customer and without prior notice if in the Company's sole judgment, the customer's continued service will be detrimental to the Company's general service.

(Cont'd on Sheet No. 3.16)

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.15)

13~~14~~. Contracts.

Contract for Service

The Company shall not be required to make extensions of service, as provided for in Item 14 below, unless the customer or customers to be initially served by such extensions of service enter into an agreement with the Company, prior to the beginning of construction that sets forth the obligations and commitments of the parties to the contract. The terms of the contract may require the customer to provide a satisfactory guarantee to the Company for the performance of the customer's obligations thereunder.

By receiving service under a specific tariff or rider, the customer or his or its heirs, successors and assigns 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.

14~~15~~. Extension of Service.

The Company shall, upon proper application for service from overhead and/or underground distribution facilities, provide necessary facilities for rendering adequate service, without charge for such facilities, when the estimated total revenue for a period of two and one-half years to be realized by the Company from permanent and continuing customers on such extension is at least equal to the estimated cost of such extension. If the estimated cost of the extension required to furnish adequate service is greater than the total estimated revenue from such extension, such an extension shall be made by the Company under the following conditions:

(a) Upon proper applications for such extension and adequate provision for payment to the Company by such applicants of that part of the estimated cost of such extension over and above the amount which would have qualified as provided for above, the Company shall proceed with such extension, or

(b) If, in the opinion of the Company, the estimated cost of such extension and the prospective revenue to be received from it is so meager as to make it doubtful whether the revenue from the extension would ever pay a fair return on the investment involved in such extension; or in a case of real estate development with slight or no immediate demand for service; or in the case of an installation requiring extensive equipment with

(Cont'd on Sheet No. 3.17)

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.16)

slight or irregular service; then, in any of the above cases, the Company shall submit the same to the Commission for investigation and determination as to the public convenience and necessity of such extension, and if so required, the conditions under which it shall be made, and

(c) For each customer, exclusive of the initial applicants considered in the making of an extension, connected to such an extension within the period of six years from the completion of such extension, the Company shall refund to such initial applicants, in proportion to their respective contributions toward the cost of such extension, an amount equal to two and one-half times the estimated annual revenue from such new customer, less the cost to service such new customer, but the total of all refunds to any such applicant shall in no event exceed the aforesaid contribution of such applicant, and

(d) If the Company has reason to question the financial stability of the customer and/or the life of the operation is uncertain or temporary in nature, such as construction projects, oil and gas well drilling, sawmills and mining operations, the customer shall pay a contribution in aid of construction, consisting of the estimated labor cost to install and remove the facilities required plus the cost of unsalvageable material, before the facilities are installed. In making determinations under this provision, the Company will consider relevant information such as financial statements, annual reports and other information provided by the customer. The Company will copy the Commission and the OUCC staff on any customer correspondence regarding the application of this provision to a customer. Should a dispute arise concerning the application of this provision, either the Company or the customer may submit such dispute to the Commission for investigation and determination as to the conditions under which such extension shall be made.

The applicants shall also agree to pay their portion of such estimated costs for primary facilities.

For service (defined as the conductors and equipment for delivering energy, not to exceed 600 volts, from the electrical supply system to the wiring system of the premises served) the applicant shall have the right to install same subject to such reasonable specifications and inspections as might be prescribed by the Company.

(Cont'd on Sheet No. 3.18)

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.17)

The Company may require the applicant to submit to the Company sufficient designs and/or plans for the service lines before proceeding. If the Company provides the designs and/or plans for the service lines, the Company may require the applicant to reimburse the Company its costs. The Company shall have no responsibility for service lines installed by the applicant.

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.

The Company shall notify customers seeking extension of service that any dispute arising concerning the application of this provision may be submitted to the Commission for investigation and determination.

15~~16~~. Service that Replaces Inadequate Facilities.

The Company will, upon proper notification of increased load to be served, provide the necessary facilities for rendering adequate service, without charge for such facilities, when the estimated increase in revenue for a period of two and one-half years to be realized by the Company is at least equal to the estimated net cost to improve such facilities. There will be no retirement charge in this situation.

If the estimated net cost of the improved facilities required to furnish adequate service is greater than the estimated increase in revenue to be realized by the Company over two and one-half years, the customer shall make adequate provision for payment to the Company for the difference.

16~~17~~. 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 specified by the Company for such purpose, as required to serve such customer. The customer shall provide suitable space for the installation of Company's measuring instruments so that the latter will be protected from injury by the elements or through the negligence or deliberate acts of the customer or any other person who is not an agent or employee of the Company.

(Cont'd on Sheet No. 3.19)

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.18)

17~~18~~. 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 except as provided herein. Service will not be furnished under any schedule 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. This prohibition precludes customer participation, either directly or indirectly through a third party, in a wholesale demand response program offered by an RTO or other entity unless such program has been reviewed and approved by the Commission.

It shall be understood that upon the termination of a contract, the customer may elect to renew the contract upon the same or another tariff published by the Company and applicable to the customer's requirements, except that 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 electric supply under the terms of the tariff elected by the customer.

A customer may not change from one tariff to another in less than 12 months or during the term of contract except with the consent of 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 which are suitable for operation with the character of the service supplied by the Company, and 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 Company may disconnect service without request by the customer and without prior notice if in the Company's sole judgment, the customer's continued service will be detrimental to the Company's general service.

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.

(Cont'd on Sheet No. 3.20)

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.19)

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 be 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 his connected load.

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

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.

The Company shall collect and manage customer data in providing service to its customers. The Company shall take appropriate measures to protect this data in its possession against loss, theft, and unauthorized access. For more information regarding the Privacy Policy visit the Company website at https://www.indianamichiganpower.com/Privacy.aspx

18~~19~~. Residential Service.

Individual residences shall be served individually under the residential service tariff. Customer may not take service for two or more separate residences 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 building or trailer court with a number of individual residential units where the service is currently taken through a single meter, such service will be supplied under the appropriate general service tariff.

Where customer is presently receiving service through such master meter, the fair allocation, through submetering, of each dwelling unit's electrical consumption shall not constitute the reselling of such service.

All electricity delivered to a new building at which units of such premises are separately rented, leased, or owned, shall be sold on the basis of individual meter measurement for each such occupancy unit, except for electricity used in hotels, motels, and other similar transient lodging, or where the service applicant establishes in writing, furnished to the utility before commencement of construction of the new building, that costs of purchasing and installing separate meters in such building exceed the long run benefits of individual metering of units.

(Cont'd on Sheet No. 3.21)

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.20)

Where a single-family house, constructed prior to April 2, 1980, is converted to include separate living quarters or dwelling units for more than one family, or where two or more families occupy a single-family house with separate cooking facilities, the owner may, instead of providing separate wiring for each dwelling unit, take service through a single meter under the residential service tariff Single-family homes, constructed subsequent to April 2, 1980, are not allowed to be sub-divided and served through a single meter under any applicable tariff. The owner of a single-family house considering sub-dividing such dwellings must provide each dwelling unit with a separate meter in accordance with the Indiana Utility Regulatory Commission's Order in Cause No. 35781.

The residential service tariff shall cease to apply to that portion of a residence which becomes regularly used for business or other gainful purposes; however, where the principal use of energy will be for residential purposes but a small amount of energy will be used for nonresidential purposes, such nonresidential use will be permitted only when the equipment for such use is within the capacity of a single 3,000-watt branch circuit and the nonresidential consumption is less than the residential use on the premises. When the nonresidential equipment exceeds the above stated maximum limit, the entire nonresidential wiring must be separated from the residential wiring so that it may be metered separately, and the nonresidential load will be billed under the appropriate general service tariff or the entire service will be billed 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.

19~~20~~. Temporary Service.

Temporary service is electric service that is required during the construction phase of a project. 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 the installation of temporary service. The Company reserves the right to require a written contract for temporary service, at its option.

(Cont'd on Sheet No. 3.22)

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
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ORIGINAL SHEET NO. 3.22

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.21)

20~~21~~. Voltages.

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

Secondary		Primary
Single Phase	Three Phase	Three Phase
120/240 Volts	120/208 Volts	4160/2400 Volts
120/208 Volts	120/240 Volts	12470/7200 Volts
240/480 Volts	277/480 Volts	34500/19950 Volts
	480 volts	

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

Subtransmission Single or Three Phase	Transmission Three Phase	EHV Transmission Three Phase
13.8 kV	138 kV	345 kV
27.6 kV		765 kV
34.5 kV		
69 kV		

Voltages listed above are not available at all locations. The Company must be consulted regarding their availability at any particular location. Subtransmission service at 13.8 kV and 27.6 kV is withdrawn except for present installations of customers receiving service at premises served prior to July 11, 1986.

21~~22~~. Meter Testing.

The Company will test meters used for billing customers in accordance with rules as currently approved by the Indiana Utility Regulatory Commission. A copy of these rules is on file at the Company's office.

The Company shall test the accuracy of registration of a meter upon written request by a customer. A second test of this meter may be requested after twelve (12) months. The first and second tests of a customer's meter shall be at no cost to the customer.

(Cont'd on Sheet No. 3.23)

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
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ORIGINAL SHEET NO. 3.23

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.22)

The customer will pay the cost of any subsequent tests of the customer's meter in accordance with Item No. 6 of the Terms and Conditions of Service if (1) the meter was tested within the prior thirty-six (36) months at the customer's request and was found to be registering within the Commission-approved limits at that time; (2) the test is made at the customer's request or due to a billing dispute and (3) the meter is found to be registering within the approved limits.

22~~23~~. Employees Discount.

Regular employees who have been in the Company employ for six months or more and are the head of the family or mainly responsible for maintenance of the premises they occupy may, at the discretion of the Company, secure a reduction in their residential electric bills. The rate for standard electric service (017) shall consist of a monthly service charge of $15.00~~20.00~~ plus 10.138~~11.407~~ ¢ per kWh for the first 900 kWh consumed monthly and 9.466~~10.934~~ ¢ per kWh over 900, plus adjustments as required under the Applicable Riders. Employees who install a Company-approved storage water-heating system will be subject to a rate of 5.635~~6.594~~ ¢ per kWh under the conditions set forth in the storage water-heating provision or load management water-heating provision of Tariff R.S (80-052, 100-053, and 120-054). Employees who meet eligibility criteria are able to participate in PEV programs.

Employees who use energy-storage or other load-management devices with time-differentiated load characteristics approved by the Company may receive service under the provisions of Tariff R.S.-OPES (036). The TOD rate shall be 15.520~~17.333~~ ¢ per /kWh for all consumption during the on-peak period and 5.635~~6.594~~ ¢ per kWh for all consumption during the off-peak period. The service charge is $17.00~~20.25~~ per customer per month.

Employees who take service under the conditions set forth in Tariff R.S.-TOD (034) will be subject to a rate of 15.520~~17.333~~ ¢ per kWh for all consumption during the on-peak period and 5.635 ~~6.594~~ ¢ per kWh for all consumption during the off-peak period. The service charge is $17.00~~20.25~~ per customer per month.

Employees who take service under the conditions set forth in Tariff R.S.-TOD2 (041) will be subject to a rate of 34.098~~39.893~~ ¢ per kWh for all consumption during the on-peak period and 8.330 ~~9.355~~ ¢ per kWh for all consumption during the off-peak period. The service charge is $17.00~~20.00~~ per customer per month.

23~~24~~. Utility Residential Weatherization Program (URWP).

Upon customer request, Indiana Michigan Power Company (Company) may provide financial assistance in the form of loans to residential customers for the cost of certain energy conservation measures.

(Cont'd on Sheet No. 3.24)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.23)

Such loans will be limited to existing customer-owned, single-family houses, duplexes, triplexes, or four-family residences that use electricity for space heating or air conditioning. Such loans will be provided only after (a) the Company deems the customer's credit rating satisfactory, (b) the customer enters into a financing agreement with the Company, and (c) the premises have had a Residential Conservation Service Program audit.

The Company will not itself sell or install energy conservation measures, but may assist the customer in this regard by financing the cost of such conservation measures in amounts up to $1,500 with a maximum repayment period of three years.

Repayment of URWP loans will be in equal monthly installments over a period up to 36 months with the first payment due no later than one month after completion of the work. Where the customer elects to finance the cost of energy conservation measures, interest will be charged at an effective annual percentage rate of 6 percent per year on the monthly unpaid balance.

The Company will not charge interest if the loan is repaid in 90 days.

24~~25~~. Customer Initiated Power Quality Investigations.

When requested by the customer to investigate any power quality issues not related to "no power" service calls, that affect service to customer owned facilities that are connected to the Company's system, the Company will conduct an initial investigation at no charge to the customer. The Company will make a reasonable attempt to resolve any problems when the Company is found to be at fault. After notifying the customer of a no-fault finding, 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 costs incurred.

25~~26~~. Advanced Meter Infrastructure (AMI) Meter Opt-out Provision (Residential Customers Only).

Customers served on a residential tariff can opt-out of receiving an AMI meter and continue to be served from an Automated Meter Reading (AMR) meter.

To be eligible to receive or retain an AMR meter, the customer shall have no documented instances, within the past 24 months, of known unauthorized use, theft, or fraud. Further, the customer will have zero instances of threats of violence toward Company employees or its agents.

Customers selecting an AMR meter as an AMI opt-out, shall have the option to provide the Company with accurate and timely monthly meter readings, at no additional charge, or pay the following charges per premise:

I&M Indiana Residential Customer AMI Opt-out Charges

Up Front Charge	$80.30	A one-time charge per meter only if the request is received after the AMI meter is already installed
Monthly Charge	$16.48	Per month at each premise

Customers will be given reasonable notice of the AMI opt-out option.

Customers electing this provision will not be able to access the benefits of having an AMI meter. All charges and provisions of the customer's applicable tariff shall apply.

(Cont'd on Sheet No. 3.25)

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 3.25

TERMS AND CONDITIONS OF SERVICE
(Cont'd from Sheet No. 3.24)

26~~27~~. Customer Requested Disconnection / Reconnection at Station Transformer

Whenever, at the customer's request, the Company is required to perform a disconnection and / or reconnection at a customer or Company owned station transformer, switch or breaker, the customer shall reimburse the Company for the entire cost incurred in making such connections which shall include all labor costs, transportation and equipment costs and any materials used not to exceed $1,500. In the event that such costs are expected to exceed $1,500, the Company shall provide the Customer with a binding estimate detailing the scope of work and associated costs to perform such work prior to the date on which the work is scheduled to commence.~~.~~

27~~28~~. Plug-in Electrical Vehicle Pilot Program

Notwithstanding other rules stated within these Terms and Conditions of Service, the Company is offering a pilot Plug-in Electric Vehicle (PEV) Program to promote PEV off-peak charging. This pilot provides incentive rebates for residential and small commercial customers with the purchase of eligible PEV's for the installation of charging ports. The pilot program is also aimed at removing some of the barriers that keep commercial and industrial customers from installing chargers for various types of electric vehicles and equipment. Additional incentives for these customers and multi-unit dwellings may include the choice of $250 per port installed rebate OR 5 (five) years of revenue credits to apply against construction costs of new Company facilities to serve these charging stations.

ISSUED BY
STEVEN F. BAKER
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FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

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INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

TARIFF R.S.
(Residential Electric Service)

Availability of Service.

Available for residential electric service through one single-phase meter to individual residential customers including rural residential customers engaged principally in agricultural pursuits. Limited three phase service may be available upon approval by the Company.

Rate. (Tariff Codes 015 - 016)

Service Charge: $15.00 ~~20.00~~ per customer per month

Energy Charge:

First 900 kWh	11.136 ~~12.405~~ ¢ per kWh
All Over 900 kWh	10.464 ~~11.932~~ ¢ per kWh

Minimum Charge.

This tariff is subject to a minimum monthly charge equal to the monthly service charge.

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

Storage Water-Heating Provision.

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

(Cont'd on Sheet No. 4.1)

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 4.1

TARIFF R.S.
(Residential Electric Service)

(Cont'd from Sheet No. 4)

If the customer installs a Company-approved storage water-heating system which consumes electrical energy only during off-peak hours 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 6.095 ~~7.173~~ ¢ per kWh.

013 (b) For Minimum Capacity of 100 gallons, the last 400 kWh of use in any month shall be billed at 6.095 ~~7.173~~ ¢ per kWh.

014 (c) For Minimum Capacity of 120 gallons or greater, the last 500 kWh of use in any month shall be billed at 6.095 ~~7.173~~ ¢ per kWh.

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 "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, Monday through Friday. The off-peak billing period is defined as those hours not designated as on-peak hours.

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 judgment 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.

Load Management Water-Heating Provision. (Tariff Code 011)

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 6.095 ~~7.173~~ ¢ per kWh.

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 "Rate" as set forth above.

(Cont'd on Sheet No. 4.2)

ISSUED BY
STEVEN F. BAKER
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FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

TARIFF R.S.
(Residential Electric Service)

(Cont'd from Sheet No. 4.1)

For the purpose of this provision, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, Monday through Friday. The off-peak billing period is defined as those hours not designated as on-peak hours.

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 judgment 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.

Contract.

A written agreement may, at the Company's option, be required to fulfill the provisions of Items 2, 14~~5~~, and/or 17~~8~~ of the Terms and Conditions of Service.

Special Terms and Conditions.

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

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS (Net Metering Service Rider), Tariff COGEN/SPP or by special agreement with the Company.

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 5.0**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF R.S.D.
(Residential Service – Demand Metered)

Availability of Service.

Available for residential electric service through one single-phase demand meter to individual residential customers. Availability is limited to the first 4,000 customers applying for service under this tariff.

Rate. (Tariff Code 018)

Service Charge: $17.00 ~~15.20~~ per customer per month

Energy Charge: 9.699 ~~11.389~~ ¢ per kWh for all kWh

Demand Charge: $1.846 ~~2.617~~ per kW for all on-peak kW

For the purpose of this tariff, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, Monday through Friday. The off-peak billing period is defined as those hours not designated as on-peak hours.

Minimum Charge.

This tariff is subject to a minimum monthly charge equal to the monthly service charge.

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

Contract.

A written agreement may, at the Company's option, be required to fulfill the provisions of Items 2, 14~~5~~, and/or 17~~8~~ of the Terms and Conditions of Service.

Special Terms and Conditions.

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

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS (Net Metering Service Rider), Tariff COGEN/SPP or by special agreement with the Company.

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION
DATE
IN CAUSE NO. 45576

TARIFF R.S. – OPES
(Residential Off-Peak Energy Storage)

Availability of Service.

Available to customers eligible for Tariff R.S. (Residential Service) who use energy-storage devices with time-differentiated load characteristics approved by the Company, such as electric thermal storage space-heating and/or cooling systems 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.

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 the on-peak and off-peak billing periods. Customer-specific information will be held as confidential and the data presented in any analysis will protect the identity of the individual customer.

Rate. (Tariff Code 032)

Service Charge: $17.00 ~~20.25~~ per customer per month

Energy Charge: 17.222 ~~18.855~~ ¢ per kWh for all on-peak kWh
6.095 ~~7.173~~ ¢ per kWh for all off-peak kWh

For the purpose of this tariff, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, Monday through Friday. The off-peak billing period is defined as those hours not designated as on-peak hours.

Minimum Charge.

This tariff is subject to a minimum monthly charge equal to the monthly service charge.

Conservation and Load Management Credit.

For the combination of an approved electric thermal storage space-heating and/or cooling system and water heater, all of which are designed to consume electrical energy only during the off-peak billing period as previously described in this tariff, each residence will be credited 1.044¢ per kWh for all kWh used during the off-peak billing period for a total of 60 monthly billing periods following the installation and use of these devices in such residence.

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

(Cont'd on Sheet No. 6.1)

TARIFF R.S. – OPES
(Residential Off-Peak Energy Storage)

(Cont'd from Sheet No. 6)

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus three percent of the amount of the bill in excess of $3.

Contract.

A written agreement may, at the Company's option, be required to fulfill the provisions of Items 2, 14~~5~~, and/or 17~~8~~ of the Terms and Conditions of Service.

Separate Metering Provision.

Customers shall have the option of receiving service under Tariff R.S. for general-use load by separately wiring such load to a standard, residential meter.

Special Terms and Conditions.

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

The Company reserves the right to inspect at all reasonable times the energy storage devices and load management devices which qualify the residence for service and conservation and load management credits 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 judgment the availability conditions of this tariff are being violated, it may discontinue billing the customer under this tariff and commence billing under the appropriate tariff.

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS (Net Metering Service Rider), Tariff COGEN/SPP or by special agreement with the Company.

TARIFF R.S. – PEV
(Residential Service Plug-in Electric Vehicle)

Availability of Service.

Available to customers eligible for Tariff RS (Residential Service) who use Plug-In Electric Vehicles (PEV) and are in good standing with the Company. Customers under this tariff may not operate distributed generation resources or participate in the Company's Net Metering Service Rider.

A standard meter will measure total residence kWh usage and an additional submeter capable of measuring electrical energy consumption during on-peak and off-peak billing periods will be installed to separately measure PEV kWh usage. No second meter charge for submeter if monthly PEV usage is 250 kWh or greater. Total residence usage will be billed under Tariff RS Monthly Rates. A credit will be applied to the customer's bill for all off-peak PEV kWh usage measured at the submeter and the credit will be issued under Tariff (029). There is no billing adjustment for on-peak PEV usage which will be billed at the normal Tariff RS rate.

Rate.

All household usage (Tariff RS):	Tariff RS rates and service charge apply
PEV Submeter (Tariff 029):	-3.364 ~~4.192~~ ¢ (credit) per kWh for all off-peak hours $1.60 ~~1.65~~ second meter charge if monthly PEV usage is < 250 kWh

For the purpose of this tariff, the daily on-peak billing period is defined as 6 a.m. to 11 p.m., local time. The off-peak billing period is defined as those hours not designated as on-peak hours.

Pilot Incentive Rebate.

Customers participating in this tariff may be eligible to receive a one-time enrollment rebate of $500 for 240 volt wiring and / or level 2 EV charger with proof of qualifying PEV purchase. Incentives are limited to the first 1,000 customers enrolling in PEV tariffs annually.

Minimum Charge.

This tariff is subject to a minimum monthly charge equal to the monthly service charge(s). The second meter charge for the PEV submeter is waived each month the PEV usage is 250 kWh or greater.

Applicable Riders.

Monthly charges computed for usage under the Tariff RS shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44. Riders will not be applied to usage measured by the PEV Submeter.

(Continued on Sheet 7.1)

TARIFF R.S. – PEV
(Residential Service Plug-in Electric Vehicle)

(Cont'd from Sheet No. 7)

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

Contract.

A written agreement may, at the Company's option, be required to fulfill the provisions of Items 2, 14~~5~~, and/or 17~~8~~ of the Terms and Conditions of Service.

Special Terms and Conditions.

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

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 8

TARIFF R.S. – TOD
(Residential Service Time-of-Day)

Availability of Service.

This tariff is withdrawn except for the present installations of customers receiving service hereunder at premises served prior to the first cycle in the billing month of June 2022. When new or upgraded facilities are required to maintain service to a Tariff R.S. TOD customer after this date, the customer will be removed from Tariff R.S. TOD and be required to take service under an appropriate Residential Service tariff for which the customer qualifies.

Rate. (Tariff Code 030)

Service Charge: $17.00 ~~20.25~~ per customer per month

Energy Charge: 17.222 ~~18.855~~ ¢ per kWh for all on-peak kWh
6.095 ~~7.173~~ ¢ per kWh for all off-peak kWh

For the purpose of this tariff, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, Monday through Friday. The off-peak billing period is defined as those hours not designated as on-peak hours.

Minimum Charge.

This tariff is subject to a minimum monthly charge equal to the monthly service charge.

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

(Cont'd on Sheet No. 8.1)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 8.1

TARIFF R.S. – TOD
(Residential Time-of-Day Service)

(Cont'd from Sheet No. 8)

Contract.

A written agreement may, at the Company's option, be required to fulfill the provisions of Items 2, 14~~5~~, and/or 17~~8~~ of the Terms and Conditions of Service.

Special Terms and Conditions.

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

Customer with cogeneration and/or small power production facilities shall take service under Rider NMS (Net Metering Service Rider), Tariff COGEN/SPP or by special agreement with the Company.

TARIFF R.S. – TOD2
(Residential Service Time-of-Day 2)

Availability of Service.

Available to individual residential customers on a voluntary basis for residential electric service through one single-phase, multi-register meter capable of measuring electrical energy consumption during variable pricing periods. Limited three phase service may be available upon approval by the Company. Residential customers that do not currently have an AMI meter may request one in order to participate in this tariff.

Rate. (Tariff Code: 021)

Service Charge: $17.00 ~~20.00~~ per customer per month

Energy Charge: 9.185 ~~10.176~~ ¢ per kWh for all low-cost hours
37.097 ~~43.396~~ ¢ per kWh for all high-cost hours

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.

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

(Cont'd on Sheet No. 9.1)

TARIFF R.S. – TOD2
Residential Service Time-of-Day 2)

(Cont'd from Sheet No. 9)

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

Contract.

A written agreement may, at the Company's option, be required to fulfill the provisions of Items 2, 14~~5~~, and/or 17~~8~~ of the Terms and Conditions of Service.

Special Terms and Conditions.

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

Existing customers may initially choose to take service under this tariff without satisfying any requirement to remain on their current tariff for at least 12 months.

Customer with cogeneration and/or small power production facilities shall take service under Rider NMS (Net Metering Service Rider), Tariff COGEN/SPP or by special agreement with the Company.

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER

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DATED
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TARIFF R.S. - EZB
(Residential EZ Bill)

Tariff Codes (045), (046) and (047)

Availability of Service

Available on a voluntary limited basis for customers receiving residential electric service, who have lived in their current residence for at least the previous twelve (12) months, have had their electricity priced on Tariff R.S. (Residential Electric Service) 015, 016, 017 or Tariff R.S.- EZB (Residential EZ Bill) for at least the previous twelve (12) months, have twelve (12) months of actual meter readings, have a load profile that can, at the sole discretion of the Company, be modeled with reasonable predictability, and are a customer in good standing as defined in the I&M Tariff Book.

Tariff R.S. - EZB offers will not be made to accounts where the monthly calculated billing amount is less than twenty-five ($25) dollars.

Conditions of Service

The Company will offer to eligible customers the opportunity to receive residential electric service at an agreed to Monthly EZ Bill Charge for twelve (12) consecutive billing months with no true-up in customers' bills at the end of the twelve (12) consecutive billing months. To participate, customers must enter into a 12-month Service Agreement. The Monthly EZ Bill Charge will be calculated starting with twelve (12) or more months of past Actual kWh Usage data adjusted for weather normalization and any applicable Usage Adjustment Factor, using the following formula:

$$\frac{1}{12}\sum_{1}^{12}[\mathit{Expected\ Monthly\ Usage}(\mathit{Energy\ Charges} + \mathit{Rider\ Charges})(1 + \mathit{Program\ Fee}) + \mathit{Monthly\ Service\ Charge}]$$

Applicable taxes and amounts owed for other services will be added to the Monthly EZ Bill Charge.

Term of Service Agreement

Service hereunder shall be for a period of twelve (12) months. All eligible EZ Bill offers will be updated annually with the previous year's usage plus any applicable Usage Adjustment Factor and sent to the customer. Service Agreements will automatically renew unless the customer notifies the Company otherwise before the end of the Grace Period.

A customer who withdraws from the EZ Bill program prior to the end of the 12-month period may be required to pay a Removal Charge and an Administrative Fee. If the amount of electricity such customer actually used results in a billing amount under Tariff R.S. that is greater than the amount for which they have been billed under Tariff R.S. - EZB, such customers must pay that difference. Customer will not receive any refund or credit for amounts paid under Tariff R.S. - EZB if the amount of electricity actually used results in a billing amount under Tariff R.S. that is less than the amount for which such customer has been billed.

If the customer's actual monthly kWh usage is at least 15% greater than the revised expected monthly kWh usage, excluding the effects of weather, then the Company will send the customer a warning letter. After two warning letters, the Company has the right to remove the customer from the program, return the customer to the customer's previous standard service tariff and apply a Removal Charge and Administrative Fee.

(Continued on Sheet No. 10.1)

TARIFF R.S. - EZB
(Residential EZ Bill)
(Cont'd from Sheet No. 10)

Definitions

Actual kWh Usage: The actual amount of energy (kWh) consumed by the customer during the month.

Administrative Fee: A $50.00 fee to compensate Company for costs associated with customers leaving the program prior to the end of the EZ Bill 12-month participation period.

Applicable Taxes: Taxes applicable to Company's Tariff R.S.

Energy Charges: The per-kWh rates forecasted to be applicable to Tariff R.S. during the participation period projected for the EZ Bill 12-month offering period.

Expected Monthly kWh Usage: Customer's projected monthly kWh usage adjusted for normal weather and any expected changes in usage.

Grace Period: The 45 days after the customer's annual renewal date during which the customer may withdraw from the program without payment of the Removal Charge and Administrative Fee.

Monthly EZ Bill Charge: A monthly charge offered to customers applicable over a specific 12-month period with no true-up in customers' bills at the end of twelve (12) consecutive billing months.

Monthly Service Charge: Monthly Service Charge as indicated in Tariff R.S.

Removal Charge: The charges the customer may be assessed for removal from the program. The charge represents the difference between the amount the customer paid on the EZ Bill Program and the amount the customer would have paid under Tariff R.S.

Revised Expected Monthly kWh Usage: Customer's expected monthly kWh usage adjusted for weather and any expected changes in usage.

Rider Charges: All rider charges forecasted to be applicable to residential service during the participation period projected for the EZ Bill 12-month offering period.

Program Fee: A charge up to 9%, used to mitigate the Company's risk for weather and price fluctuations associated with the EZ Bill program offering.

Usage Adjustment Factor: Includes usage adjusted for any expected changes in usage. First year usage adjustment is three and sixth-tenths percent (3.6%), the second year is eight-tenths of a percent (0.8%) and zero percent (0.00%) thereafter.

Special Terms and Conditions

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

The customer shall enter into a Service Agreement with the Company that shall specify the Monthly EZ Bill Charge amount that the customer will be required to pay.

(Continued on Sheet No. 10.2)

TARIFF R.S. - EZB
(Residential EZ Bill)

(Cont'd from Sheet No. 10.1)

The term of the Service Agreement will be for twelve (12) months. Each year, before the 12-month EZ Bill period is over, the Company will calculate a new Monthly EZ Bill Charge for the following year and notify the customer of the new Monthly EZ Bill Charge amount. The customer will automatically renew at the new Monthly EZ Bill Charge amount for the following year, unless the customer notifies the Company of the customer's desire to be removed before the end of the Grace Period.

Removal from EZ Bill service:

(a) ***Move from Current Residence –*** If customer has moved from his or her current residence so that there is a tenant change, before the 12-month Service Agreement period expires, Company will calculate what the customer would have paid under Tariff R.S., including applicable riders and taxes during the EZ Bill Service Agreement period. If the customer has paid less than Tariff R.S. charges, the customer will be charged a Removal Charge for the difference. If the customer has paid more than the Tariff R.S. charges, the customer will not be refunded or credited with the difference. The Administration Fee will be waived for customers who change locations.
(b) ***Disconnection from EZ Bill Service–*** If a customer becomes delinquent in EZ Bill payments, Company will follow the standard procedures for Tariff R.S. customers. If customer is involuntarily disconnected for any reason other than safety, customer will be removed from EZ Bill service, and applicable Removal Charges and Administrative Fee may apply.
(c) ***Increased Actual kWh Usage over Revised Expected Monthly kWh Usage*** – If, after two warning letters of excess usage, the customer has actual monthly kWh usage that is at least 15% greater than revised expected monthly kWh usage, then the Company has the right to remove the customer from the program and return them to their previous standard service tariff. Applicable Removal Charges and Administrative Fee may apply.
(d) ***Customer Voluntary Removal*** – If customer chooses to leave EZ Bill service prior to the end of the 12-month Service Agreement period, customer will be removed from EZ Bill service, and applicable Removal Charges and Administrative Fee may apply. No Administrative Fee will be charged to customers moving to another non-standard tariff offering. After the end of each Service Agreement period, eligible customers will automatically renew for the next EZ Bill Service Agreement period unless the customer indicates the customer's intention to return to Tariff R.S. service. If the Tariff R.S. election is made within the Grace Period, no Removal Charges and Administrative Fee will apply.
(e) ***Grace Period*** – If customer mistakenly fails to withdraw from EZ Bill service prior to their automatic renewal, customer will be allowed to withdraw for up to 45 days from their renewal date without payment of the Removal Charge and Administrative Fee.
(f) ***Other Reason*** – If customer leaves or is removed from EZ Bill service before the end of the Service Agreement period for any other reason, applicable Removal Charges and Administrative Fee may apply.

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 11**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF R.S. – CPP
(Residential Service Critical Peak Pricing)

Availability of Service.

Available on a voluntary basis to individual residential customers who receive service from the Company. Customers must have an advanced meter installed to be eligible for service under this tariff.

Customers electing to take service under the Critical Peak Pricing Tariff are expected to remain on this schedule for a minimum of one (1) year. If the customer terminates service under this schedule, the customer will not be eligible to receive service under this schedule for a period of one (1) year from termination date. Customers receiving service under Rider NMS or other AMI based demand response or time of use programs or tariffs are not eligible for service under RS-CPP.

Monthly Rate (Tariff Codes 060).

Winter (Off Peak Season) Months: October 1 through April 30	Billing Hours	Rates
Monthly Service Charge ($)		15.00 ~~20.00~~
Energy Charge (¢ per kWH)	All Except Critical Peak	10.464 ~~11.932~~
Critical Peak Hours (¢ per kWH)	When Notified	50.000

Summer (On Peak Season) Months: May 1 through September 30	Billing Hours	Rates
Monthly Service Charge ($)		15.00 ~~20.00~~
		Energy Charges (¢ per kWH)
Low Cost Hours	Midnight – 7 AM and 9 PM - Midnight	5.727 ~~5.700~~
Medium Cost Hours	7 AM – 1 PM and 7 PM – 9 PM	6.095 ~~7.173~~
High Cost Hours	1 PM – 7 PM	24.113 ~~28.207~~
Critical Peak Hours	When Notified	50.000

NOTE: Unless a critical peak event is called, all kWh consumed on weekends (all hours of the day on Saturdays and Sundays) are billed at the low cost level.

Critical Peak Events.

Critical peak events shall be called at the sole discretion of the Company. Critical peak events shall not exceed five (5) hours per day and 15 events per calendar year.

(Cont'd on Sheet No. 11.1)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

TARIFF R.S. CPP
(Residential Service Critical Peak Pricing)

(Cont'd from Sheet No. 11)

Critical Peak Event Notification.

Customers will be notified by the Company by 7 PM the evening prior to a critical peak event. Receipt of the price notification is the customers' responsibility. The Company has the ability to cancel a scheduled event with at least two (2) hours-notice prior to the start of an event due to unforeseen changes in conditions.

In the event of an emergency, the Company may invoke a critical peak event at any time during the year, and will use best efforts to provide notice two (2) hours prior to the start of the event. Such emergency events will not count toward the total number of critical peak events, as defined above.

The Company will offer email notification and may also offer text messaging and/or other technologies approved by the Company. Any customer owned technology equipment utilized for notification shall be subject to Company review and approval.

Minimum Charge.

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

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Term of Contract.

A written agreement may, at the Company's option, be required to fulfill the provisions of Items 2, 14~~5~~, and/or 17~~8~~ of the Terms and Conditions of Service.

Special Terms and Conditions.

This tariff is subject to the Company's Terms and Conditions of Service. This tariff is available for single-phase service only.

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 12**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF G.S.
(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 demand exceeds 1,000 kW.

Tariff Code	Service Voltage	Greater than 10 kW demand	First 4,500 kWh	Over 4,500 kWh	Monthly Service Charge
		($/kW)	(¢/kWh)	(¢/kWh)	($)
215, 218, ~~240, 241, 242~~	Sec.	3.019 ~~3.237~~	10.510 ~~13.330~~	9.441 ~~10.851~~	25.00
217, ~~244, 245, 246~~	Primary	1.892 ~~2.039~~	9.714 ~~12.412~~	8.674 ~~10.057~~	180.00
236~~, 248~~	Subtran.	0.000	8.852 ~~11.457~~	7.827 ~~9.125~~	180.00
239~~, 250~~	Trans.	0.000	8.789 ~~11.376~~	7.775 ~~9.036~~	180.00

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

Credit Modifying Rate.

Bills computed under the rate set forth herein will be modified by credits as follows:

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.(Cont'd on Sheet No. 12.1)

ISSUED BY
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FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

TARIFF G.S.
(General Service)

(Cont'd from Sheet No. 12)

Monthly Billing Demand.

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 corrected to the nearest kW. For accounts over 100 kW, monthly billing demand established hereunder shall not be less than 60 percent of the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 kW. If more than 50 percent of the customer's connected load is for electric space heating purposes, the minimum monthly billing demand will be 25 percent of the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 kW for the billing months of June through October. The Metered Voltage adjustment, as set forth above, shall not apply to the customer's minimum monthly billing demand. The Monthly Billing Demand shall be rounded to the nearest kW. The Demand Charge shall be applied to monthly demands in excess of 10 kW.

The Company reserves the right to install a demand meter on any customer receiving service under this tariff although any customer with an average monthly kWh usage of 4,500 kWh or greater a demand meter will be installed by the Company.

Off-Peak Hour Provision.

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 percent of the maximum demand created during the billing month nor less than 60 percent of the customer's highest previously established monthly billing demand during the past 11 months, or 100 kW. Availability is limited to the first 50 customers applying for service under this provision.

For the purpose of this provision, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, Monday through Friday. The off-peak billing period is defined as those hours not designated as on-peak hours.

Contract.

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 2, 14~~5~~, and/or 17~~8~~ of the Terms and Conditions of Service.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods of one year or greater for all customers served under 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.

The Company may not be required to supply capacity in excess of that contracted for except by mutual agreement.

(Cont'd on Sheet No. 12.2)

TARIFF G.S.
(General Service)

(Cont'd from Sheet No. 12.1)

Special Terms and Conditions.

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

This tariff is also available to customers having other sources of 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 10 kW. The Company shall not be obligated to supply demands in excess of that contracted for.

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS (Net Metering Service Rider), Tariff COGEN/SPP or by special agreement with the Company.

Load Management Time-of-Day Provision.

Available to customers who use energy-storage devices with time-differentiated load characteristics approved by the Company, such as electric thermal storage space-heating and/or cooling systems 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.

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

Rate. (Tariff Code 223~~, 251~~)

Service Charge:	$25.00	per customer per month
Energy Charge:	13.150 ~~15.226~~ ¢	per kWh for all on-peak kWh
	6.118 ~~7.198~~ ¢	per kWh for all off-peak kWh

For the purpose of this provision, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, Monday through Friday. The off-peak billing period is defined as those hours not designated as on-peak hours.

The customer shall be responsible for all local facilities required to take service under this provision.

(Cont'd on Sheet No. 12.3)

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 12.3

TARIFF G.S.
(General Service)

(Cont'd from Sheet No. 12.2)

Optional Unmetered Service Provision.

This tariff provision is withdrawn except for the present installations of customers receiving service hereunder at premises served prior to May 1, 2020. When new or upgraded facilities are required to maintain service to an existing customer, the customer shall be removed from the unmetered provision and placed on a standard metered, general service tariff for which the customer qualifies.

Available to customers with 12-month average demands less than 10 kW, and who use the Company's service for commercial purposes consisting of small, fixed electric load 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 on the basis of the increased load for the full period such load was connected or for a period of one year, whichever period is shorter, pursuant to 170 IAC 4-1-14(B).

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. Such calculated energy shall then be billed at the following rate:

Rate. (Tariff Codes 204 and 214)

Service Charge:	$9.80 ~~9.45~~ per customer per month
Energy Charge:	10.510 ~~13.330~~ ¢ per kWh

If the company determines, at its sole option, that unmetered service can be provided to a customer without the use of a line transformer or service drop, the above unmetered service provisions shall apply, except that the monthly service charge shall be $5.25 per customer per month.

This provision is subject to the Terms and Conditions of Tariff G.S.

ISSUED BY
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EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER

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INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 13

Tariff G.S. – TOD
(General Service – Time-of-Day)

Availability of Service.

This tariff is withdrawn except for the present installations of customers receiving service hereunder at premises served prior to the first cycle in the billing month of June 2022. When new or upgraded facilities are required to maintain service to a Tariff GS-TOD customer, the customer shall be removed from Tariff GS-TOD and be required to take service under an appropriate General Service tariff for which the customer qualifies.

Rate.

Tariff Code	Service Voltage	On-Peak Energy Charge (¢/KWH)	Off-Peak Energy Charge (¢/KWH)	Monthly Service Charge ($)
229	Secondary	13.150 ~~15.226~~	6.118 ~~7.198~~	25.00
227	Primary	10.061 ~~12.068~~	6.062 ~~7.140~~	180.00

For the purpose of this tariff, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, Monday through Friday. The off-peak billing period is defined as those hours not designated as on-peak hours.

Minimum Charge.

This tariff is subject to a minimum monthly charge equal to the monthly service charge.

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

(Cont'd on Sheet No. 13.1)

ISSUED BY
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EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

Tariff G.S. – TOD
(General Service – Time-of-Day)

(Cont'd from Sheet No. 13)

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 values will be adjusted for billing purposes. If the Company elects to adjust kWh 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.

Contract.

A written agreement may, at the Company's option, be required to fulfill the provisions of Items 2, 14~~5~~, and/or 17~~8~~ of the Terms and Conditions of Service.

Special Terms and Conditions.

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

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS (Net Metering Service Rider), Tariff COGEN/SPP or by special agreement with the Company.

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 14

TARIFF G.S. – TOD2
(General Service Time-of-Day 2)

Availability of Service.

Available on a voluntary basis for general service customers with 12-month average demands less than 10 kW through one multi-register meter capable of measuring electrical energy consumption during variable pricing periods. General Service customers that do not currently have an AMI meter may request one in order to participate in this tariff

Rate. (Tariff Code: 221)

Service Charge:	$25.00	per customer per month
Energy Charge:	9.230 ~~9.929~~ ¢ per kWh for all low-cost hours 31.954 ~~35.510~~ ¢ per kWh for all high-cost hours	

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.

(Cont'd on Sheet No. 14.1)

ISSUED BY
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EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

TARIFF G.S. – TOD2
(General Service Time-of-Day 2)

(Cont'd from Sheet No. 14)

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

Contract.

A written agreement may, at the Company's option, be required to fulfill the provisions of Items 2, 14~~5~~, and/or 17~~8~~ of the Terms and Conditions of Service.

Special Terms and Conditions.

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

Existing customers may initially choose to take service under this tariff without satisfying any requirement to remain on their current tariff for at least 12 months.

Customer with cogeneration and/or small power production facilities shall take service under Rider NMS (Net Metering Service Rider), Tariff COGEN/SPP or by special agreement with the Company.

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 15

TARIFF G.S. - EZB
(General Service EZ Bill)

Tariff Code (216) G.S. – EZB

Availability of Service

Available on a voluntary limited basis for customers receiving general electric service, who have occupied their current location for at least the previous twelve (12) months, have had their electricity priced on Tariff G.S. 215 (General Service) or Tariff G.S. - EZB (General Service EZ Bill) for at least the previous twelve (12) months, have twelve (12) months of actual meter readings, have a load profile that can, at the sole discretion of the Company, be modeled with reasonable predictability, have an expected monthly kWh usage over the previous twelve (12) months of 3,000 kWh or less, demand of less than 10 kW, and are a customer in good standing as defined in the I&M Rate Book.

Tariff G.S. - EZB offers will not be made to accounts where the monthly calculated billing amount is less than twenty-five ($25) dollars.

Conditions of Service

The Company will offer to eligible customers the opportunity to receive general electric service at an agreed to Monthly EZ Bill Charge for twelve (12) consecutive billing months with no true-up in customers' bills at the end of the twelve (12) consecutive billing months. To participate, customers must enter into a 12-month Service Agreement. The Monthly EZ Bill Charge will be calculated starting with twelve (12) or more months of past Actual kWh Usage data adjusted for weather normalization and any applicable Usage Adjustment Factor, using the following formula:

$$\frac{1}{12}\sum_{1}^{12}[Expected\ Monthly\ Usage(Energy\ Charges + Rider\ Charges)(1 + Program\ Fee) + Monthly\ Service\ Charge]$$

Applicable taxes and amounts owed for other services will be added to the Monthly EZ Bill Charge.

Term of Service Agreement

Service hereunder shall be for a period of twelve (12) months. All eligible EZ Bill offers will be updated annually, with the previous year's usage plus any applicable Usage Adjustment Factor and sent to the customer. Service Agreements will automatically renew unless the customer notifies the Company otherwise before the end of the Grace Period.

A customer who withdraws from the EZ Bill program prior to the end of the 12-month period may be required to pay a Removal Charge and an Administrative Fee. If the amount of electricity such customer actually used results in a billing amount under Tariff G.S. that is greater than the amount for which they have been billed under Tariff G.S. - EZB, such customers must pay that difference. Customer will not receive any refund or credit for amounts paid under Tariff G.S. - EZB if the amount of electricity actually used results in a billing amount under Tariff G.S. that is less than the amount for which such customer has been billed.

If the customer's actual monthly kWh usage is at least 15% greater than the revised expected monthly kWh usage, excluding the effects of weather, then the Company will send the customer a warning letter. After two warning letters, the Company has the right to remove the customer from the program and return them to their previous standard service tariff and apply a Removal Charge and Administrative Fee.

(Continued on Sheet No. 15.1)

ISSUED BY
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EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

TARIFF G.S. - EZB
(General Service EZ Bill)

(Continued from Sheet No. 15)

Definitions

Actual kWh Usage: The actual amount of energy (kWh) consumed by the customer during the month.

Administration Fee: A $50.00 fee to compensate Company for costs associated with customers leaving the program prior to the end of the EZ Bill 12-month participation period.

Applicable Taxes: Taxes applicable to Company's Tariff G.S.

Energy Charges: The per-kWh rates forecasted to be applicable to Tariff G.S. during the participation period projected for the EZ Bill 12-month offering period.

Expected Monthly kWh Usage: Customer's projected monthly kWh usage adjusted for normal weather and any expected changes in usage.

Grace Period: The 45 days after the customer's annual renewal date during which the customer may withdraw from the program without payment of the Removal Charge and Administrative Fee.

Monthly EZ Bill Charge: A monthly charge offered to customers applicable over a specific 12-month period with no true-up in customers' bills at the end of twelve (12) consecutive billing months.

Monthly Service Charge: Monthly Service Charge as indicated in Tariff G.S.

Removal Charge: The charges the customer may be assessed for removal from the program. The charge represents the difference between the amount the customer paid on the EZ Bill Program and the amount the customer would have paid under Tariff G.S.

Revised Expected Monthly kWh Usage: Customer's expected monthly kWh usage adjusted for observed weather.

Rider Charges: All rider charges forecasted to be applicable to Tariff G.S. during the participation period projected for the EZ Bill 12-month offering period.

Program Fee: A charge up to 9%, used to mitigate the Company's risk for weather and price fluctuations associated with the EZ Bill program offering.

Usage Adjustment Factor: Includes usage adjusted for any expected changes in usage. First year usage adjustment is three and sixth-tenths percent (3.6%), the second year is eight-tenths of a percent (0.8%) and zero percent (0%) thereafter.

Special Terms and Conditions

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

The customer shall enter into a Service Agreement with the Company that shall specify the Monthly EZ Bill Charge amount that the customer will be required to pay.

(Continued on Sheet No. 15.2)

TARIFF G.S. - EZB
(General Service EZ Bill)

(Continued from Sheet No. 15.1)

The term of the Service Agreement will be for twelve (12) months. Each year, before the 12-month EZ Bill period is over, the Company will calculate a new Monthly EZ Bill Charge for the following year and notify the customer of the new Monthly EZ Bill Charge amount. The customer will automatically renew at the new Monthly EZ Bill Charge amount for the following year, unless the customer notifies the Company of the customer's desire to be removed before the end of the Grace Period.

Removal from EZ Bill service:

(a) ***Move from Current Location*** – If customer has moved from his or her current location so that there is a tenant change, before the 12-month Service Agreement period expires, Company will calculate what the customer would have paid under Tariff G.S., including applicable riders and taxes during the EZ Bill Service Agreement period. If the customer has paid less than Tariff G.S. charges, the customer will be charged a Removal Charge for the difference. If the customer has paid more than the Tariff G.S. charges, the customer will not be refunded or credited with the difference. The Administration Fee will be waived for customers who change locations.
(b) ***Disconnection from EZ Bill Service*** – If a customer becomes delinquent in EZ Bill payments, Company will follow the standard procedures for Tariff G.S. customers. If customer is involuntarily disconnected for any reason other than safety, customer will be removed from EZ Bill service and returned to their previous standard service tariff. Applicable Removal Charges and Administrative Fee may apply.
(c) ***Increased Actual kWh Usage over Revised Expected Monthly kWh Usage*** – If, after two warning letters of excess usage, the customer has actual monthly kWh usage that is at least 15% greater than revised expected monthly kWh usage, then the Company has the right to remove the customer from the program and return them to their previous standard service tariff. Applicable Removal Charges and Administrative Fee may apply.
(d) ***Customer Voluntary Removal*** – If customer chooses to leave EZ Bill service prior to the end of the 12-month Service Agreement period, customer will be removed from EZ Bill service, and applicable Removal Charges and Administrative Fee may apply. No Administrative Fee will be charged to customers moving to another non-standard tariff offering. After the end of each Service Agreement period, eligible customers will automatically renew for the next EZ Bill Service Agreement period unless the customer informs the Company of the customer's intention to change tariffs. If a valid tariff election is made within the Grace Period, no Removal Charges will apply.
(e) ***Grace Period*** – If customer mistakenly fails to withdraw from EZ Bill service prior to their automatic renewal, customer will be allowed to withdraw for up to 45 days from their renewal date without payment of the Removal Charge and Administrative Fee.
(f) ***Other Reason*** – If customer leaves or is removed from EZ Bill service before the end of the Service Agreement period for any other reason, applicable Removal Charges and Administrative Fee may apply.

TARIFF G.S. – PEV
(General Service Plug-in Electric Vehicle)

Availability of Service.

Available to customers on Tariff GS, in good standing with the Company, having averaged less than 4,500 kWh use per month in the previous 12 months and use Plug-in Electric Vehicles (PEV). Customers under this tariff may not operate distributed generation resources or participate in the Company's Net Metering Service Rider.

Customers electing service under this tariff may choose from two available options. Option 1 allows for a stand-alone PEV service in addition to their existing Tariff GS service. Option 2 allows for a PEV Submeter placed to separately meter PEV usage within their existing GS service.

Option 1 – Stand-alone PEV Service: All PEV usage shall be metered through one, multi-register meter capable of measuring electrical energy consumption during on-peak and off-peak billing periods. All PEV kWh usage will be billed at the following Monthly Rates in addition to the customers qualifying Tariff GS account.

Rate: (Tariff 219)

Monthly Service Charge	$ 25.00
All PEV Off – Peak kWh	7.100 ~~7.740~~ ¢ per kWh
All PEV On – Peak kWh	11.883 ~~12.853~~ ¢ per kWh

For the purpose of this tariff, the daily on-peak billing period is defined as 6 a.m. to 11 p.m. Off-peak billing period is defined as those hours not designated as on-peak hours

Option 2 – Submetered PEV Time-of-Day: A submeter capable of measuring electrical energy consumption during on-peak and off-peak billing periods will be installed to separately measure PEV kWh usage. Total General Service usage will be billed at the customers Tariff GS Monthly Rates. A credit will be applied to the customer's bill for all off-peak PEV kWh usage measured at the submeter and billed under Tariff (220). There is no billing adjustment for PEV on-peak usage. No second meter charge for the PEV Submeter applies when monthly PEV usage is 250 kWh or greater.

Rate. (Tariff 220)

All General Service Usage	Current Tariff GS rate and Service Charge apply
PEV Usage	-3.410 ~~5.590~~ ¢ (Credit) per kWh Off-Peak
	$ 1.60 ~~1.65~~ second meter charge if monthly PEV use is < 250 kWh

For the purpose of this tariff, the daily on-peak billing period is defined as 6 a.m. to 11 p.m. Off-peak billing period is defined as those hours not designated as on-peak hours.

(Continued on Sheet No. 16.1)

TARIFF G.S. – PEV
(General Service Plug-in Electric Vehicle)

(Continued from Sheet No. 16)

Pilot Incentive Rebates.

Customers participating in this tariff may be eligible to receive a one-time enrollment rebate of $500 for 240 volt wiring and / or level 2 EV charger with proof of qualifying PEV purchase. Incentives are limited to the first 1,000 customers enrolling in PEV tariffs annually.

Minimum Charge.

This tariff is subject to a minimum monthly charge equal to the monthly service charge(s). The second meter charge for the PEV submeter Option 2 is waived each month the PEV usage is 250 kWh or greater.

Applicable Riders.

Monthly charges computed for both services under Option 1 shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44. For Option 2, the applicable riders will be charged on usage metered under the customers Tariff GS account, not for usage measured by the PEV Submeter.

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

Contract.

A written agreement may, at the Company's option, be required to fulfill the provisions of Items 2, 14~~5~~, and/or 17~~8~~ of the Terms and Conditions of Service.

Special Terms and Conditions.

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

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 17

TARIFF G.S. – CPP
(General Service Critical Peak Pricing)

Availability of Service.

Available on a voluntary basis for general service to customers with 12-month average metered demands of less than 10 kW who take service under an applicable tariff from the Company. Customers must have an advanced meter installed to be eligible for service under this tariff.

Customers electing to take service under the Critical Peak Pricing Tariff are expected to remain on this schedule for a minimum of one (1) year. If the customer terminates service under this schedule, the customer will not be eligible to receive service under this schedule for a period of one (1) year from termination date. Customers receiving service under Rider NMS or other AMI based demand response or time of use programs or tariffs are not eligible for service under GS-CPP.

Monthly Rate (Tariff Code 260).

Winter (Off Peak Season) Months: October 1 through April 30	Billing Hours	Rates
Monthly Service Charge ($)		25.00
Energy Charge (¢ per KWH)	All Except Critical Peak	10.463 ~~13.286~~
Critical Peak Hours (¢ per KWH)	When Notified	50.000

Summer (On Peak Season) Months: May 1 through September 30	Billing Hours	Rates
Monthly Service Charge		$ 25.00
		Energy Charges (¢ per KWH)
Low Cost Hours	Midnight – 7 AM and 9 PM - Midnight	5.990 ~~4.498~~
Medium Cost Hours	7 AM – 1 PM and 7 PM – 9 PM	6.118 ~~7.198~~
High Cost Hours	1 PM – 7 PM	24.764 ~~19.531~~
Critical Peak Hours	When Notified	50.000

NOTE: Unless a critical peak event is called, all kWh consumed on weekends (all hours of the day on Saturdays and Sundays) are billed at the low cost level.

Critical Peak Events.

Critical peak events shall be called at the sole discretion of the Company. Critical peak events shall not exceed five (5) hours per day and 15 events per calendar year.

(Cont'd on Sheet No. 17.1)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 17.1

TARIFF G.S. CPP
(General Service Critical Peak Pricing)

(Cont'd from Sheet No. 17)

Critical Peak Event Notification.

Customers will be notified by the Company by 7 PM the evening prior to a critical peak event. Receipt of the price notification is the customers' responsibility. The Company has the ability to cancel a scheduled event with at least two (2) hours-notice prior to the start of an event due to unforeseen changes in conditions.

In the event of an emergency, the Company may invoke a critical peak event at any time during the year, and will use best efforts to provide notice two (2) hours prior to the start of the event. Such emergency events will not count toward the total number of critical peak events, as defined above.

The Company will offer email notification and may also offer text messaging and/or other technologies approved by the Company. Any customer owned technology equipment utilized for notification shall be subject to Company review and approval.

Minimum Charge.

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

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Term of Contract.

A written agreement may, at the Company's option, be required to fulfill the provisions of Items 2, 14~~5~~, and/or 17~~8~~ of the Terms and Conditions of Service.

Special Terms and Conditions.

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

Customer with cogeneration and/or small power production facilities shall take service under Rider NMS (Net Metering Service Rider), Tariff COGEN/SPP or by special agreement with the Company.

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 18**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

Tariff L.G.S.
(Large General Service)

Availability of Service.

Available for general service customers ~~with 12-month average metered demands less than 1,000 kW. Customer's monthly billing demands under this tariff shall not be less than 60 kVA.~~ Customers may continue to qualify for service under this tariff until their 12-month average billing demand exceeds 1,000 kW~~VA~~.

Rate.

Tariff Code	Service Voltage	Demand Charge ($/KW~~VA~~)	First 300 kWh per kW (¢/KWH)	Over 300 kWh per kW (¢/KWH)	Monthly Service Charge ($)
240-242	Secondary	7.548 ~~6.241~~	7.523	3.184 ~~3.888~~	25.00 ~~35.30~~
244-246	Primary	4.730 ~~4.229~~	7.270 ~~7.310~~	3.030 ~~3.777~~	180.00 ~~159.20~~
248	Subtransmission	0 ~~1.220~~	7.175 ~~7.209~~	2.983 ~~3.726~~	180.00 ~~159.20~~
250	Transmission	0 ~~1.205~~	7.124 ~~7.133~~	2.968 ~~3.687~~	180.00 ~~159.20~~

Excess kVA Demand Charge

The monthly kVA demand shall be determined by dividing the maximum metered kW demand by the average monthly power factor. The excess kVA demand, if any, shall be the amount by which the monthly kVA demand exceeds the greater of (a) 101 % of the maximum metered kW demand or (b) 60 kVA. The metered voltage adjustment, as set forth below, shall apply to the customers excess kVA demand.

The Excess kVA Charge under this tariff shall be as follows:

Tariff Code	Service Voltage	Excess kVA Demand Charge ($ / kVA)
240 - 242	Secondary	7.548
244 - 246	Primary	4.730
248	Subtransmission	4.730
250	Transmission	4.730

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44~~42~~.

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

(Cont'd on Sheet No. 18.1)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

Tariff L.G.S.
(Large General Service)

(Cont'd from Sheet No. 18)

Monthly Billing Demand.

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 corrected to the nearest kW. For accounts over 100 kW, monthly billing demand established hereunder shall not be less than 60 percent of the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 kW. If more than 50 percent of the customer's connected load is for electric space heating purposes, the minimum monthly billing demand will be 25 percent of the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 kW for the billing months of June through October. The Metered Voltage adjustment, as set forth below, shall not apply to the customer's minimum monthly billing demand. The Monthly Billing Demand shall be rounded to the nearest kW.

Off-Peak Hour Provision.

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 percent of the maximum demand created during the billing month nor less than 60 percent of the customer's highest previously established monthly billing demand during the past 11 months, or 100 kW~~VA~~. Availability is limited to the first 50 customers applying for service under this provision.

For the purpose of this provision, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, Monday through Friday. The off-peak billing period is defined as those hours not designated as on-peak hours.

Adjustments to Rate.

Bills computed under the rate set forth herein will be adjusted as follows:

~~A. Power Factor~~

~~The rate set forth in this tariff is subject to power factor based upon the maintenance by the customer of an average monthly power factor of 85 percent, leading or lagging, as measured by integrating meters. When the average monthly power factor is above or below 85 percent, leading or lagging, the kWh as metered will, for billing purposes, be multiplied by the constant, rounded to the nearest 0.0001, derived from the following formula:~~

$$\cancel{\text{Constant} = 0.9510 + \left[0.1275\left[\frac{\text{RKVAH}}{\text{KWH}}\right]^{2}\right]}$$

(Cont'd on Sheet No. 18.2)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

Tariff L.G.S.
(Large General Service)

(Cont'd from Sheet No. 18.1)

~~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 and excess kVA values will be adjusted for billing purposes. If the Company elects to adjust kWh, ~~and~~ kW~~VA~~ and excess kVA 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.

Terms of Contract.

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 2, 14, and/or 17 of the Terms and Conditions of Service.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods of one year or greater for all customers served under 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.

The Company may not be required to supply capacity in excess of that contracted for except by mutual agreement.

(Cont'd on Sheet No. 18.3)

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 18.3**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

Tariff L.G.S.
(Large General Service)

(Cont'd from Sheet No. 18.2)

Special Terms and Conditions.

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

This tariff is also available to customers having other sources of 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~~VA~~ which the Company might be required to furnish, but not less than 100 kW~~VA~~. The Company shall not be obligated to supply demands in excess of that contracted for.

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS (Net Metering Service Rider), Tariff COGEN/SPP or by special agreement with the Company.

Load Management Time-of-Day Provision.

Available to customers who use energy-storage devices with time-differentiated load characteristics approved by the Company, such as electric thermal storage space-heating and/or cooling systems 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.

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

Rate. (Tariff Code 251)

Service Charge:	$25.00 ~~35.30~~ per customer month
Energy Charge:	13.150 ~~14.691~~¢ per kWh for all on-peak kWh
	6.118 ~~5.224~~¢ per kWh for all off-peak kWh

For the purpose of this provision, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, Monday through Friday. The off-peak billing period is defined as those hours not designated as on-peak hours.

The customer shall be responsible for all local facilities required to take service under this provision.

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 19**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

Tariff L.G.S. – TOD
(Large General Service – Time-of-Day)

Availability of Service.

Available for general service customers. Customers may continue to qualify for service under this tariff until their 12-month average metered demand exceeds 1,000 kW. Availability is limited to the first 500 customers applying for service under this tariff.

Rate.

Tariff Code	Service Voltage	Demand Charge ($/KW)	On-Peak Energy Charge (¢/KWH)	Off-Peak Energy Charge (¢/KWH)	Monthly Service Charge ($)
253	Secondary	7.548 ~~8.092~~	9.580 ~~10.294~~	5.118 ~~7.198~~	25.00
255	Primary	4.731 ~~5.096~~	8.438 ~~9.188~~	5.062 ~~7.140~~	180.00

For the purpose of this tariff, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, Monday through Friday. The off-peak billing period is defined as those hours not designated as on-peak hours.

Minimum Charge.

This tariff is subject to a minimum monthly charge equal to the monthly service charge.

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

(Cont'd on Sheet No. 19.1)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

Tariff L.G.S. – TOD
(Large General Service – Time-of-Day)

(Cont'd from Sheet No. 19)

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.

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 corrected to the nearest kW. For accounts over 100 kW, monthly billing demand established hereunder shall not be less than 60 percent of the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 kW. If more than 50 percent of the customer's connected load is for electric space- heating purposes, the minimum monthly billing demand will be 25 percent of the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 kW for the billing months of June through October. The Metered Voltage adjustment, as set forth above, shall not apply to the customer's minimum monthly billing demand.

Contract.

A written agreement may, at the Company's option, be required to fulfill the provisions of Items 2, 14~~5~~, and/or 17~~8~~ of the Terms and Conditions of Service.

Special Terms and Conditions.

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

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS (Net Metering Service Rider), Tariff COGEN/SPP or by special agreement with the Company.

RESERVED FOR FUTURE USE

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 21

TARIFF I.P.
(Industrial Power)

Availability of Service.

Available for general service customers. Customer's monthly billing demands under this tariff shall not be less than 600 kW. The customer shall contract for a sufficient capacity to meet normal maximum requirements with written contracts being required for capacity levels of 1,500 kW and greater.

Rate.

Tariff Code	Service Voltage	Demand Charge ($/kW)	First 410 kWh per kW (¢/kWH)	Over 410 kWh per kW (¢/kWH)	Monthly Service Charge ($)
327	Secondary	15.645 ~~15.591~~	5.540 ~~6.906~~	1.104 ~~1.181~~	155.00
322	Primary	13.113 ~~13.012~~	5.185 ~~6.675~~	1.067 ~~1.143~~	235.00
323	Subtransmission	10.034 ~~9.131~~	4.940 ~~6.586~~	1.053 ~~1.128~~	235.00
324	Transmission	9.918 ~~9.065~~	4.547 ~~6.540~~	1.045 ~~1.113~~	235.00

Reactive Demand Charge

Reactive demand charge for each kVAr of leading or lagging reactive demand in excess of 50% of the kW metered demand will be charged at $1.50 / kVAr.

Minimum Charge.

This tariff is subject to a minimum monthly charge equal to the sum of the Monthly Service Charge, the product of the Minimum Demand Charge and the monthly billing demand, and all applicable riders.

The Minimum Demand Charge under this tariff shall be as follows:

Tariff Code	Service Voltage	Minimum Demand Charge ($/kW)
327	Secondary	20.250 ~~18.292~~
322	Primary	17.559 ~~15.632~~
323	Subtransmission	14.541 ~~11.716~~
324	Transmission	14.374 ~~11.628~~

(Cont'd on Sheet No. 21.1)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

TARIFF I.P.
(Industrial Power)

(Cont'd from Sheet No. 21)

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3, there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

Monthly Billing Demand.

The billing demands in kW for each plant shall be taken each month as the single-highest 15-minute integrated peak in kW, as registered at such plant during the month by a demand meter or indicator, subject to the off-peak hour provision, but the monthly demand so established shall in no event be less than 60 percent 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) 1,000 kW. The Metered Voltage adjustment, as set forth below, shall not apply to the customer's minimum monthly billing demand.

Off-Peak Hour Provision.

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 percent of the maximum demand created during the billing month nor less than 60 percent of either (a) the contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

For the purpose of this provision, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, Monday through Friday. The off-peak billing period is defined as those hours not designated as on-peak hours.

(Cont'd on Sheet No. 21.2)

TARIFF I.P.
(Industrial Power)

(Cont'd from Sheet No. 21.1)

Adjustments to Rate.

Bills computed under the rates set forth herein will be adjusted as follows:

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, kVAr values will be adjusted for billing purposes. If the Company elects to adjust kWh, kW and kVAr 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.

Terms 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. Where new facilities are required, the Company reserves the right to require initial contracts for periods of greater than two years.

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.

The Company shall not be required to supply capacity in excess of that contracted for except by mutual agreement.

(Cont'd to Sheet No. 21.3)

TARIFF I.P.
(Industrial Power)

(Cont'd from Sheet No. 21.2)

Special Terms and Conditions.

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

This tariff is also available to customers having other sources of 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 1,000 kW. The Company shall not be obligated to supply demands in excess of that contracted for.

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS (Net Metering Service Rider), Tariff COGEN/SPP or by special agreement with the Company.

TARIFF C.S. – IRP2
(Contract Service Interruptible Power)

Availability of Service.

Available to customers having interruptible demands of 1,000 kW or greater, who contract for 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 235,000 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 for approval. 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. Any such test or verification may require actual physical interruption or curtailment, to the extent such testing or interruption is required under PJM's Emergency Load Response Program.

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.

(Cont'd on Sheet No. 22.1)

TARIFF C.S. – IRP2
(Contract Service Interruptible Power)

(Cont'd from Sheet No. 22)

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.

Confidentiality.

All terms and conditions of any written contract under this schedule shall be protected from disclosure as confidential, proprietary trade secrets pursuant to Indiana Code 5-14-3 if:

a. either the customer or the Company requests a Commission determination of confidentiality, and

b. the Commission finds that the party requesting such protection has shown good cause, by affidavit, 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 Service shall apply to service under this tariff.

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 23

TARIFF M.S.
(Municipal and School Service)

This tariff is withdrawn except for the present installations of customers receiving service hereunder at premises served prior to April 6, 1981. When new or upgraded facilities are required to maintain service to a Tariff M.S. customer, the customer shall be removed from Tariff M.S. 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 Indiana, 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.

Tariff Codes	Demands Greater than 10 kW ($)	First 4,500 kWh (¢/kWh)	Over 4,500 kWh (¢/kWh)	Monthly Service Charge ($)
543 / 544	7.548 ~~3.237~~	10.061 ~~13.101~~	6.673 ~~9.713~~	20.25

Minimum Charge.

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

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Monthly Demand.

The monthly demand in kW shall be the metered demand taken each month as the single-highest 15-minute integrated peak in kW, as registered during the month by a 15-minute integrating demand meter or indicator. Monthly demand charges will apply to customers with demands greater than 10 kW.

(Cont'd on Sheet No. 23.1)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

TARIFF M.S.
(Municipal and School Service)

(Cont'd from Sheet No. 23)

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3. 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.

Terms of Contract.

Contracts under this tariff will be made for not less than one year with self-renewal provisions to extend the term of the contract for successive periods of one year until either party shall give at least 60 days' notice to the other of the intention to discontinue at the end of any yearly period. The Company will have the right to require contracts for periods of longer than one year.

Special Terms and Conditions.

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

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS (Net Metering Service Rider), Tariff COGEN/SPP or by special agreement with the Company.

TARIFF W.S.S.
(Water and Sewage Service)

Availability of Service.

Available for the supply of electric energy to waterworks systems and sewage disposal systems.

Rate.

Tariff Code	Service Voltage	First 300 kWh Per kW (¢/kWh)	Over 300 kWh Per kW (¢/kWh)	Monthly Svc Charge $
545	Secondary	7.274 ~~8.760~~	7.065 ~~8.551~~	31.00
546	Primary	6.296 ~~7.686~~	6.090 ~~7.479~~	137.00
542	Subtransmission	4.983 ~~6.261~~	4.784 ~~6.062~~	137.00

Minimum Charge.

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

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

(Cont'd on Sheet No. 24.1)

TARIFF W.S.S.
(Water and Sewage Service)

(Cont'd from Sheet No. 24)

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3. 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.

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.

Terms of Contract.

For customers with 12-month average demands greater than 1,000 kW, contracts under this tariff will be made 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. For customers with demands less than 1,000 kW, a written agreement may, at the Company's option, be required to fulfill the provisions of Items 2, 14~~5~~, and/or 17~~8~~ of the Terms and Conditions of Service.

(Cont'd on Sheet No. 24.2)

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 24.2

TARIFF W.S.S.
(Water and Sewage Service)

(Cont'd from Sheet No. 24.1)

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.

Special Terms and Conditions.

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

This tariff is also available to customers having other sources of 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. The Company shall not be obligated to supply demands in excess of that contracted for.

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS (Net Metering Service Rider), Tariff COGEN/SPP or by special agreement with the Company.

Optional Time-of-Day Provision.

Customers have the option to receive service on the following rate:

Rate.

Tariff Code	Service Voltage	On-Peak Energy Charge (¢/kWh)	Off-Peak Energy Charge (¢/kWh)	Monthly Service Charge ($)
547	Secondary	7.925 ~~9.881~~	6.118 ~~7.198~~	31.00
549	Primary	6.998 ~~8.846~~	5.840 ~~6.880~~	137.00
551	Subtransmission	5.798 ~~7.539~~	5.641 ~~6.657~~	137.00

For the purpose of this provision, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, Monday through Friday. The off-peak billing period is defined as those hours not designated as on-peak hours.

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

TARIFF E.H.G.
(Electric Heating General)

This tariff is withdrawn except for the present installations of customers receiving service hereunder at premises served prior to April 6, 1981. When new or upgraded facilities are required to maintain service to a Tariff E.H.G. customer, the customer shall be removed from Tariff E.H.G. and be required to take service under an appropriate general service tariff for which the customer qualifies.

Availability of Service.

Available for the entire requirements of general service customers who have electric-heating equipment installed and in regular active use as the primary means of space heating on the customer's premises.

Rate. (Tariff Code 208)

Service Charge:	$ 25.00	per customer per month
Energy Charge:	6.475 ~~11.240~~ ¢ per kWh	
Demand Charge	$ 7.548 ~~3.237~~ per kW	

Minimum Charge.

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

Monthly Demand.

The monthly demand in kW shall be the metered demand taken each month as the single-highest 15-minute integrated peak in kW, as registered during the month by a 15-minute integrating demand meter or indicator.

(Cont'd on Sheet No. 25.1)

TARIFF E.H.G.
(Electric Heating General)

(Cont'd from Sheet No. 25)

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

Terms of Contract.

Annual.

Special Terms and Conditions.

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

This tariff is available only to customers where at least 50 percent of the electrical load is located inside of buildings, which are electrically heated.

Energy supplied hereunder will be delivered through not more than one single-phase or polyphase meter.

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS (Net Metering Service Rider), Tariff COGEN/SPP or by special agreement with the Company.

TARIFF O.L.
(Outdoor Lighting)

Availability of Service.

Available for outdoor lighting to individual customers, including community associations and real estate developers located in areas not covered by municipal streetlighting systems. This tariff is not available for municipal street lighting.

Customers requesting the installation of a new light shall have the obligation to insure that the requested location for the light will not be objectionable to other property owners in the immediate vicinity. In the event of a dispute that results in the removal or relocation of the installation, the customer will be responsible for the costs of removal or relocation. LED lamp wattages and lumens are approximate and actual values may vary due to the rapidly changing LED market.

Customers requesting a light that requires the installation of a new pole on their property may designate the location of the new pole, provided that the pole location is approved by the Company.

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.

Rate.

For each lamp with luminaire and an upsweep arm not over 6 feet in length, controlled by a photoelectric relay, where service is supplied from an existing pole and secondary facilities of Company:

Tariff Code						Rate Per Lamp Per Month		
						On Wood Pole with Overhead Circuitry		Post-top Lamp on Fiberglass Pole with UG Circuitry*
Standard Luminaire	Floodlight	Post Top	Nominal Lamp Wattage	Approx. Lamp Lumens	Type of Lamp	Standard Luminaire	Floodlight	
						$	$	$
094	---	121	100	9,500	HPS	8.40 ~~9.45~~	---	22.40 ~~25.10~~
097	107	---	200	22,000	HPS	11.25 ~~12.60~~	12.60 ~~14.15~~	---
098	109	---	400	50,000	HPS	18.05 ~~20.20~~	17.60 ~~19.70~~	---
---	110	---	250	17,000	MH	---	13.75 ~~15.40~~	---
---	116	---	400	28,800	MH	---	17.15 ~~19.20~~	---
129	---	---	41	4,800	LED	7.10 ~~7.95~~	---	---
130	---	---	57	5,700	LED	6.55 ~~7.35~~	---	---
---	---	152	85	8,300	LED	---	---	21.75 ~~24.40~~
131	---	---	88	8,500	LED	8.35 ~~9.35~~	---	---
135	---	---	139	14,000	LED	10.20 ~~11.45~~	---	---
138	---	---	219	23,000	LED	13.40 ~~15.05~~	---	---
---	143	---	150	18,800	LED	---	11.45 ~~12.85~~	---
---	146	---	297	37,800	LED	---	16.55 ~~18.55~~	---

* Monthly rate includes Company providing one lamp, one seventeen-foot fiberglass pole and one span of underground wire lateral not over 50 Feet in length.

(Cont'd on Sheet No. 26.1)

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 26.1

TARIFF O.L.
(Outdoor Lighting)

(Cont'd from Sheet No. 26)

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:

30 Foot Wood Pole . . . . $1.60 per month
35 Foot Wood Pole . . . . $2.35 per month
40 Foot Wood Pole . . . . $3.30 per month
Overhead Wire Span Not Over 150 Feet . . . . $1.25 per month
Underground Wire Lateral Not Over 50 Feet . . . . . $6.05 per month
(Price includes pole riser and connections)

When a customer requests service hereunder requiring wire span lengths in excess of 150 feet, special poles for fixture, 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 $8.10 per foot of excess footage, plus any and all costs required to repair, replace, or push under sidewalks, pavement, or other obstacles.

Rate: Discontinued Lamps.

The following rates apply to existing luminaires only and are not available for new business:

Tariff Code		
090	2,500 Lumen Incandescent – 189 Watt	$9.25 ~~9.80~~ per lamp per month
093	7,000 Lumen Mercury Vapor – 175 Watt	$9.65 ~~10.25~~ per lamp per month
095	20,000 Lumen Mercury Vapor – 400 Watt	$16.20 ~~17.15~~ per lamp per month
100	50,000 Lumen Mercury Vapor – 1,000 Watt	$29.15 ~~30.85~~ per lamp per month
103	3,850 Lumen Mercury Vapor – 100 Watt	$9.20 ~~9.70~~ per lamp per month
114	20,000 Lumen Mercury Vapor Flood – 400 Watt	$18.50 ~~19.55~~ per lamp per month
119	50,000 Lumen Mercury Vapor Flood – 1,000 Watt	$33.55 ~~35.50~~ per lamp per month
106	5,800 Lumen High Pressure Sodium – 70 Watt	$7.20 ~~7.65~~ per lamp per month
108	25,500 Lumen High Pressure Sodium – 250 Watt	$14.65 ~~15.50~~ per lamp per month
115	9,500 Lumen High Pressure Sodium – 100 Watt	$12.60 ~~13.35~~ per lamp per month

(Cont'd on Sheet No. 26.2)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

TARIFF O.L.
(Outdoor Lighting)

(Cont'd from Sheet No. 26.1)

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3, there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

Customer Liability.

New applications under this tariff will not be for less than one contract year for services on existing facilities and not less than five contract years when new facilities must be installed. In the case of customers requesting four or more lamps, the Company reserves the right to require a contract including such other provisions as it may deem necessary to insure payment of bills throughout the term as stated above.

Hours of Lighting.

All lamps shall burn from one-half hour after sunset until one-half hour before sunrise, every night, or approximately 4,000 per annum.

Ownership of Facilities.

All facilities necessary for service including fixtures, controls, poles, transformers, secondary's, 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.

Special Terms and Conditions.

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

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 27**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF T.O.L.
(Timed Outdoor Lighting)

Availability of Service.

Available on an experimental basis to at least 20 customers receiving service for five or more lamps under Tariff O.L. (Outdoor Lighting). This service is offered as an option to those who do not require the hours of lighting provided by Tariff O.L. The Company reserves the right to curtail availability at any time after 20 installations have been completed. This tariff is not available for municipal street lighting.

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.

Monthly Rate (Credit).

For each mercury vapor, metal halide or high pressure sodium lamp placed under the control of a time clock and turned out each night at or near midnight or under the control of a timing adapter operating for approximately seven hours each night, the following schedule of credits shall apply to the monthly charges made under Tariff O.L.

Size of Lamp In Lumens	Type of Lamp	Tariff Code	Time Clock Control $	Tariff Code	7-Hour Timing Adapter $
5,800	High Pressure Sodium		0.50 ~~55~~		0.40 ~~45~~
9,500	High Pressure Sodium		0.60 ~~70~~		0.50 ~~55~~
22,000	High Pressure Sodium		1.25 ~~40~~	112	1.00 ~~10~~
50,000	High Pressure Sodium	101	2.45 ~~75~~		1.80 ~~2.00~~
7,000	Mercury Vapor		1.05 ~~20~~		0.80 ~~90~~
20,000	Mercury Vapor	105	2.35 ~~60~~		1.70 ~~90~~
50,000	Mercury Vapor	117	5.45 ~~6.15~~	102	4.00 ~~45~~
17,000	Metal Halide		1.50 ~~70~~		1.05 ~~15~~
28,800	Metal Halide	092	2.35 ~~60~~	111	1.70 ~~90~~

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3, there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

(Cont'd on Sheet No. 27.1)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

TARIFF T.O.L.
(Timed Outdoor Lighting)

(Cont'd from Sheet No. 27)

Contracts.

Contracts for this service will take the form of a rider attachment to the agreement for service under Tariff O.L. The minimum term of the T.O.L. service rider shall be one year and shall specify the type and number of lamps to be controlled and the control method. The Company will endeavor to comply with a customer's request to control only certain of the lamps at a given location but is not obligated to do so if, in the Company's determination, this is not practical due to duplicative wiring requirements or other such implements.

Hours of Lighting.

Lamps under control of a time clock will be extinguished each night at approximately midnight EST resulting in a reduction of the annual burning time to approximately 2,000 hours per year. Lamps under control of a timing adapter will burn approximately seven hours per night or approximately 2,555 hours per year.

Discontinued Lamps.

At the Company's option, this tariff rider may be extended to lamps which have been discontinued under Tariff O.L. In such a case, the credit to be applied monthly will be determined by allowing 2.5¢ per kWh of energy saved.

Special Terms and Conditions.

This tariff is subject to the Company's Terms and Conditions of Service and the terms and conditions of the Company's Tariff O.L.

TARIFF S.L.S.
(Streetlighting Service)

Availability of Service.

This tariff is withdrawn except for existing streetlights or traffic control signals serving those municipalities, counties, and other governmental subdivisions having contracted for such service under this tariff, Tariff S.L.N. (Streetlighting-New and Rebuilt Systems), or a special contract prior to the first effective date of Tariff E.C.L.S. (Energy Conservation Lighting Service).

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.

Monthly Rate. (Tariff Code 533)

Size of Lamp in Lumens	Type of Lamp	Price Per Lamp Per Month: On Wood Poles With Overhead Circuitry	On Metallic or Concrete Poles With: Overhead Circuitry	On Metallic or Concrete Poles With: Underground Circuitry
1,000	Incandescent	--	--	11.30 ~~12.80~~
2,500	Incandescent	--	--	15.85 ~~17.95~~
4,000	Incandescent	--	--	22.50 ~~25.55~~
7,000	Mercury Vapor	7.95 ~~9.00~~	12.10 ~~13.70~~	14.60 ~~16.55~~
20,000	Mercury Vapor	11.90 ~~13.55~~	16.85 ~~19.15~~	19.60 ~~22.25~~
50,000	Mercury Vapor	--	26.45 ~~30.00~~	--
16,000	High Pressure Sodium	12.10 ~~13.50~~	17.90 ~~19.95~~	22.55 ~~25.10~~
25,500	High Pressure Sodium	13.90 ~~15.50~~	19.80 ~~22.10~~	--

Public Efficient Streetlighting Program

The Public Efficient Streetlighting Program (PES) is a program implemented under the Company's Demand-Side Management / Energy Efficiency Program, designed to encourage energy efficient streetlighting through the conversion of existing Company-owned streetlights to LED streetlights. The PES will be performed under the terms and conditions contained in the PES as approved by the Commission.

(Cont'd on Sheet No. 28.1)

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 28.1

TARIFF S.L.S.
(Streetlighting Service)

(Cont'd from Sheet No. 28)

PES Monthly Rate. (Tariff Code 534)

Size of Lamp in Lumens	PES Type of Lamp Conversion	Price Per Lamp Per Month: On Wood Poles With Overhead Circuitry	On Metallic or Concrete Poles With: Overhead Circuitry	On Metallic or Concrete Poles With: Underground Circuitry
1,000	Incandescent > LED	--	--	11.30 ~~12.80~~
2,500	Incandescent > LED	--	--	15.85 ~~17.95~~
4,000	Incandescent > LED	--	--	22.50 ~~25.55~~
7,000	Mercury Vapor > LED	7.95 ~~9.00~~	12.10 ~~13.70~~	14.60 ~~16.55~~
20,000	Mercury Vapor > LED	11.90 ~~13.55~~	16.85 ~~19.15~~	19.60 ~~22.25~~
50,000	Mercury Vapor > LED	--	26.45 ~~30.00~~	--
16,000	High Pressure Sodium > LED	12.10 ~~13.50~~	17.90 ~~19.95~~	22.55 ~~25.10~~
25,500	High Pressure Sodium > LED	13.90 ~~15.50~~	19.80 ~~22.10~~	--

Rate for Traffic Control Signals.

For post type traffic director units, which are supplied energy for their operation but owned and maintained by the customer, having normally one lamp of 69 watts or less capacity burning at the same time except during a change in signal when no more than two lamps are burning simultaneously for a period not to exceed 15 percent of the total time to complete an entire cycle of signal changes, \$ 2.60 ~~2.90~~ /Month.

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of \$3 or less, 10 percent of the amount of the bill; and to bills in excess of \$3, there shall be added 10 percent of the first \$3, plus 3 percent of the amount of the bill in excess of \$3. Any governmental agency shall be allowed such additional period of time for payment of the net bill as the agency's normal fiscal operations required, not to exceed 30 days.

(Cont'd on Sheet No. 28.2)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER THE AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

TARIFF S.L.S.
(Streetlighting Service)

(Cont'd from Sheet No. 28.1)

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. Traffic director units may operate 24 hours per day, every day, approximately 8,760 hours per annum.

Lamp Outages.

For all outages which shall be reported daily in writing to the Company by a proper representative of the customer, the customer may deduct from the total monthly amount 1/30 of the amount which would have been paid for any lamp had no outage occurred for each day of outage beyond two working days.

Terms of Contract.

Contracts under this tariff shall be made for a 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 the initial term or any yearly period. The Company will have the right to require contracts for periods longer than one year.

TARIFF E.C.L.S.
(Energy Conservation Lighting Service)

Availability of Service.

Available for streetlighting service to municipalities, counties, and other governmental subdivisions. Also available to nongovernment entities that have written permission from the relevant municipalities, counties, and other governmental subdivision. The rates are applicable to new streetlights installed after April 6, 1981, and to 50,000 lumen high pressure sodium streetlights installed before that date. Only the lamps set forth below are available for such new service. 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 served.

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.

Monthly Rate (Tariff Code 530)					Rate Per Lamp Per Month		
					Metallic or Concrete Pole installed prior to April 6, 1981		
Nominal Lamp Wattage	Approx. Lamp Lumens	Type of Lamp	New Lamp on Existing Pole (No-Pole Rate) $	On Wood Pole with Overhead Circuitry $	Overhead Circuitry $	UG Circuitry $	Post-top lamp with Fiberglass Pole and UG Circuitry* $
70	5,800	HPS	--	6.65 ~~7.40~~	15.05 ~~16.75~~	15.35 ~~17.10~~	--
100	9,500	HPS	--	7.25 ~~8.10~~	15.60 ~~17.40~~	16.45 ~~18.30~~	13.45 ~~15.00~~
200	22,000	HPS	--	10.90 ~~12.05~~	17.05 ~~18.95~~	18.55 ~~20.60~~	--
400	50,000	HPS	--	14.25 ~~15.85~~	19.55 ~~21.75~~	21.05 ~~23.45~~	--
41	4,800	LED	7.00	12.05	--	--	--
45	5,000	LED	--	--	--	--	15.90
65	7,000	LED	--	--	--	--	16.45
85	8,300	LED	--	--	--	--	21.25
88	8,500	LED	8.00	13.05	--	--	--
139	14,000	LED	9.66	14.71	--	--	--
219	23,000	LED	12.46	17.51	--	--	--

*Monthly rate includes Company providing one lamp, one seventeen-foot fiberglass pole and one span of underground wire lateral not over 50 feet in length.

(Cont'd on Sheet No. 29.1)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER

ISSUED UNDER THE AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

TARIFF E.C.L.S.
(Energy Conservation Lighting Service)
(Cont'd From Sheet No. 29)

The following rates apply to existing luminaires and are not available for new business.

175	7,000	MV	7.70 ~~8.75~~
400	20,000	MV	12.30 ~~13.95~~

Public Efficient Streetlighting Program

The Public Efficient Streetlighting Program (PES) is a program implemented under the Company's Demand-Side Management / Energy Efficiency Program, designed to encourage energy efficient streetlighting through the conversion of existing Company-owned streetlights to LED streetlights. The PES will be performed under the terms and conditions contained in the PES as approved by the Commission. **LED lamp wattages and lumens are approximate and actual values may vary due to the rapidly changing LED market.**

PES Monthly Rate. (Tariff Code 532)

		Rate Per Lamp Per Month			
			On Metallic or Concrete Pole Installed Prior to April 6, 1981		
Approx. Lamp Lumens	PES Type of Lamp Conversion	On Wood Pole With Overhead Circuitry	Overhead Circuitry	Under-Ground Circuitry	Post-top Lamp on Fiberglass Pole With Underground Circuitry
		$	$	$	$
5,800	HPS > LED	6.65 ~~7.40~~	15.05 ~~16.75~~	15.35 ~~17.10~~	--
9,500	HPS > LED	7.25 ~~8.10~~	15.60 ~~17.40~~	16.45 ~~18.30~~	13.45 ~~15.00~~
22,000	HPS > LED	10.90 ~~12.05~~	17.05 ~~18.95~~	18.55 ~~20.60~~	--
50,000	HPS > LED	14.25 ~~15.85~~	19.55 ~~21.75~~	21.05 ~~23.45~~	--
7,000	MV > LED	7.70 ~~8.75~~	--	--	--
20,000	MV > LED	12.30 ~~13.95~~	--		--

--

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.

(Cont'd on Sheet No. 29.2)

TARIFF E.C.L.S.
(Energy Conservation Lighting Service)

(Cont'd from Sheet No. 29.1)

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. A customer paying a contribution-in-aid of construction will pay the above monthly rate for wood poles with overhead circuitry.

When direct buried underground facilities are requested by the customer, the estimated installed cost of the underground circuit will be $7.35 ~~8.20~~ per foot plus any and all cost required to repair, replace, or push under sidewalks, pavements, or other obstacles.

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3. 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.

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.

(Cont'd on Sheet No. 29.3)

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 29.3

TARIFF E.C.L.S.
(Energy Conservation Lighting Service)

(Cont'd from Sheet No. 29.2)

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.

For all outages which are reported daily in writing to the Company by a proper representative of the customer, the customer may deduct from the total amount which would have been paid had no outage occurred 1/30 of such amount per day of outage beyond two working days after such notice

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 O.L. for other new equipment. For any equipment not specified in Tariff O.L. the charge shall be based upon the Company's actual cost.

The Company will relocate or remove lamps as rapidly as labor conditions permit.

Terms of Contract.

Contracts under this tariff 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 Company will have the right to require contracts for periods of longer than one year.

Special Terms and Conditions.

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

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER

ISSUED UNDER THE AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 30

TARIFF S.L.C.
(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.

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.

This tariff is also available to community associations which have been incorporated under Indiana law as not-for-profit corporations. Such community association shall own the complete streetlighting system and have legal means available to it in its by-laws to pay for the service from funds which are secured by a continuing lien upon the properties of the members.

Service rendered hereunder is predicated upon the execution by the customer of an agreement specifying the type, number, and location of lamps to be served.

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 performances of maintenance. New installations on Company owned poles is prohibited without prior Company approval.

Rate. (Tariff Code 531)

Size of Lamp In Lumens	Type of Lamp	Price Per Lamp Per Month $
5,800	High Pressure Sodium	1.85 ~~2.10~~
9,500	High Pressure Sodium	2.25 ~~2.50~~
14,400	High Pressure Sodium	3.10 ~~3.50~~
22,000	High Pressure Sodium	3.95 ~~4.45~~
25,500	High Pressure Sodium	5.25 ~~5.95~~
50,000	High Pressure Sodium	7.45 ~~8.40~~

Size of Lamp In Watts	Type of Lamp	Price Per Lamp Per Month $
Up to 50W	LED	$0.55 ~~60~~
51W to 100W	LED	$1.20 ~~30~~
101W to 150W	LED	$1.90 ~~2.10~~
151W to 250W	LED	$2.90 ~~3.30~~

(Cont'd on Sheet No. 30.1)

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 30.1**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF S.L.C.
(Streetlighting –Customer-Owned System)

(Cont'd from Sheet No. 30)
The following rates apply to existing luminaires and are not available for new business.

Size of Lamp In Lumens	Type of Lamp	Price Per Lamp Per Month
7,000	Mercury Vapor	3.80 ~~4.30~~
11,000	Mercury Vapor	5.15 ~~5.80~~
20,000	Mercury Vapor	7.80 ~~8.80~~

Service To Be Rendered.

The Company will furnish electrical energy for the operation of lamps. Effective January 1, 2019 customer will be responsible for renewals of lamps, cleaning and replacement of glassware and all other maintenance, repair, or replacement of the customer-owned system.

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3, there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3. 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.

Hours of Lighting.

Lamps shall burn from approximately one-half hour after sunset until approximately one-half hour before sunrise, every night and all night, approximately 4,000 hours per annum.

Term of Contract.

Annual.

Special Terms and Conditions.

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

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

TARIFF S.L.C.M.
(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. Likewise, this tariff is available for lighting systems serving outdoor recreational facilities such as baseball fields and football stadiums.

This tariff is also available for such purposes to community associations which have been incorporated under Indiana law as not-for-profit corporations. Such community association shall have legal means available to it in its by-laws to pay for the service from funds which are secured by a continuing lien upon the properties of the members.

Rate. (Tariff Code 733-735)

Service Charge:		
733-Single phase 120/240 volts	$6.65 per month	
734-Single phase 240/480 volts	$13.75 ~~13.80~~ per month	
735-Three phase	$20.35 ~~20.40~~ per month	
Energy Charge:	3.468 ~~4.017~~ ¢	per kWh

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3. 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.

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.

(Cont'd on Sheet No. 31.1)

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 31.1**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF S.L.C.M.
(Streetlighting – Customer-Owned System – Metered)

(Cont'd from Sheet No. 31)

Term of Contract

A written agreement may, at the Company's option, be required to fulfill the provisions of Items 2, 14~~5~~, and/or 17~~8~~ of the Terms and Conditions of Service. Either party shall give the other 60 days' written notice of the intention to discontinue service. A separate invoice will be rendered each billing period for each meter location.

Special Terms and Conditions.

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

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 32

TARIFF F.W. – S.L.
(Fort Wayne Streetlighting – Customer Owned and Maintained System)

Availability of Service.

Available to the City of Fort Wayne, Indiana, for energy supplied through the streetlighting system that is owned and maintained by the Municipality.

Rate. (Tariff Code 525)

2.996 ~~3.397~~ ¢ per kWh.

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Payment.

Bills will be rendered monthly and will be due and payable on the 15th day of each month succeeding that in which the service is rendered.

Ledger.

A written ledger shall be maintained by the Company specifying the type, number, and location of lamps on the customer's streetlighting system. The customer shall be responsible for advising the Company of any changes affecting the type, number, and location of lamps in service that occur during the billing period.

The customer and Company will reconcile the total street lighting ledger annually and correct any known billing discrepancies. The annual reconciliation is to occur during the first billing period of each calendar year. Additionally, the customer and Company will mutually conduct annual field audits covering at least 5% of the total street lighting served under this tariff. Each year the area audited will change until the entire service area is reviewed. Discrepancies that are discovered during this audit will be corrected effective to the known date of error but in no case will this correction exceed one year.

(Cont'd on Sheet No. 32.1)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

TARIFF F.W. – S.L.
(Fort Wayne Streetlighting – Customer Owned and Maintained System)

(Cont'd from Sheet No. 32)

Determination of Energy.

The kWhs used for each month for each lamp shall be determined from the following table. KWhs used by lamps rated at values differing from those included in the following table shall be determined and added to the list as appropriate.

TOTAL MONTHLY ENERGY CONSUMPTION IN KILOWATT HOURS PER SINGLE LAMP
STREETLIGHTS (S), OUTDOOR LIGHTS (O)
ALL NIGHT LAMPS (ADJUSTED FOR PHOTOCELL OPERATION TO TOTAL 4,000 HOUR OPERATION PER YEAR)

TYPE OF LAMP AND APPROXIMATE LUMENS[1]	TOTAL WATTS	CANDLE POWER	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
INCANDESCENT														
1,000 Lumens (S)	92	100	39	32	32	28	25	22	24	27	29	35	36	39
2,500 Lumens (S,O)	189	250	79	67	67	57	51	45	48	55	60	71	75	81
SODIUM VAPOR														
3,600 L 4,000 L, 50W (S)	66		28	23	23	20	18	16	17	19	21	25	26	28
5,000 L 6,000 L, 70W (S,O)	86		36	30	30	26	23	21	22	25	28	32	34	37
8,550 L 9,500 L, 100W (S,O)	121		51	43	43	36	32	29	31	35	39	45	48	52
14,400 L 16,000 L 150W (S,O)	176		74	62	62	53	47	42	45	51	57	66	70	75
24,750 L 27,500 L, 250W (S,O)	309		130	109	109	93	83	74	79	90	99	116	122	132
45,000 L 50,000 L, 400W (S,O)	500		210	176	176	150	134	120	128	146	160	188	198	214
99,000 L 110,000 L, 750W (S)[2]	827		315	264	264	225	201	180	192	219	240	282	297	321
METAL HALIDE														
8,750 L 10,500 L, 100W (O)	156		67	55	55	47	41	37	39	45	51	59	63	67
10,800 L 14,000 L, 175W (O)	216		91	76	76	65	58	52	55	63	69	81	86	92
17,000 L 20,500 L, 250W (O)	301		127	106	106	90	81	72	77	88	96	113	119	129
28,800 L 36,000 L, 400W (O)	474		199	167	167	142	127	114	121	138	152	178	188	203
LED														
(S,O)	1		1	1	1	1	1	1	1	1	1	1	1	1
(S,O)	2		1	1	1	1	1	1	1	1	1	1	1	1
(S,O)	3		1	1	1	1	1	1	1	1	1	1	1	1
(S,O)	4		2	1	1	1	1	1	1	1	1	2	2	2
(S,O)	5		2	2	2	2	1	1	1	1	2	2	2	2
(S,O)	6		3	2	2	2	2	1	2	2	2	2	2	3
(S,O)	7		3	2	2	2	2	2	2	2	2	3	3	3
(S,O)	8		3	3	3	2	2	2	2	2	3	3	3	3
(S,O)	9		4	3	3	3	2	2	2	3	3	3	4	4
(S,O)	10		4	4	4	3	3	2	3	3	3	4	4	4
(S,O)	11		5	4	4	3	3	3	3	3	4	4	4	5
(S,O)	12		5	4	4	4	3	3	3	3	4	5	5	5
(S,O)	13		6	5	5	4	3	3	3	4	4	5	5	6
(S,O)	14		6	5	5	4	4	3	4	4	5	5	6	6
(S,O)	15		6	5	5	5	4	4	4	4	5	6	6	6

(Cont'd on Sheet No. 32.2)

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 32.2**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF F.W. – S.L.
(Fort Wayne Streetlighting – Customer Owned and Maintained System)

(Cont'd from Sheet No. 32.1)

TYPE OF LAMP AND APPROXIMATE LUMENS[1]	TOTAL WATTS	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
(S,O)	16	7	6	6	5	4	4	4	5	5	6	6	7
(S,O)	17	7	6	6	5	4	4	4	5	6	6	7	7
(S,O)	18	8	6	6	5	5	4	5	5	6	7	7	8
(S,O)	19	8	7	7	6	5	5	5	5	6	7	8	8
(S,O)	20	9	7	7	6	5	5	5	6	7	8	8	9
(S,O)	21	9	7	7	6	6	5	5	6	7	8	8	9
(S,O)	22	9	8	8	7	6	5	6	6	7	8	9	9
(S,O)	23	10	8	8	7	6	5	6	7	7	9	9	10
(S,O)	24	10	8	8	7	6	6	6	7	8	9	10	10
(S,O)	25	11	9	9	8	7	6	6	7	8	9	10	11
(S,O)	26	11	9	9	8	7	6	7	7	8	10	10	11
(S,O)	27	12	9	9	8	7	6	7	8	9	10	11	12
(S,O)	28	12	10	10	8	7	7	7	8	9	11	11	12
(S,O)	29	12	10	10	9	8	7	7	8	9	11	12	12
(S,O)	30	13	11	11	9	8	7	8	9	10	11	12	13
(S,O)	31	13	11	11	9	8	7	8	9	10	12	12	13
(S,O)	32	14	11	11	10	8	8	8	9	10	12	13	14
(S,O)	33	14	12	12	10	9	8	8	10	11	12	13	14
(S,O)	34	14	12	12	10	9	8	9	10	11	13	14	14
(S,O)	35	15	12	12	11	9	8	9	10	11	13	14	15
(S,O)	36	15	13	13	11	9	9	9	10	12	14	14	15
(S,O)	37	16	13	13	11	10	9	9	11	12	14	15	16
(S,O)	38	16	13	13	11	10	9	10	11	12	14	15	16
(S,O)	39	17	14	14	12	10	9	10	11	13	15	16	17
(S,O)	40	17	14	14	12	11	10	10	12	13	15	16	17
(S,O)	41	17	14	14	12	11	10	10	12	13	15	16	17
(S,O)	42	18	15	15	13	11	10	11	12	14	16	17	18
(S,O)	43	18	15	15	13	11	10	11	12	14	16	17	18
(S,O)	44	19	15	15	13	12	10	11	13	14	17	18	19
(S,O)	45	19	16	16	14	12	11	11	13	15	17	18	19
(S,O)	46	20	16	16	14	12	11	12	13	15	17	18	20
(S,O)	47	20	17	17	14	12	11	12	14	15	18	19	20
(S,O)	48	20	17	17	14	13	11	12	14	16	18	19	20
(S,O)	49	21	17	17	15	13	12	12	14	16	18	20	21
(S,O)	50	21	18	18	15	13	12	13	14	16	19	20	21
(S,O)	51	22	18	18	15	13	12	13	15	17	19	20	22
(S,O)	52	22	18	18	16	14	12	13	15	17	20	21	22
(S,O)	53	23	19	19	16	14	13	13	15	17	20	21	23
(S,O)	54	23	19	19	16	14	13	14	16	18	20	22	23
(S,O)	55	23	19	19	17	14	13	14	16	18	21	22	23
(S,O)	56	24	20	20	17	15	13	14	16	18	21	22	24
(S,O)	57	24	20	20	17	15	14	14	16	19	21	23	24
(S,O)	58	25	20	20	17	15	14	15	17	19	22	23	25
(S,O)	59	25	21	21	18	16	14	15	17	19	22	24	25
(S,O)	60	26	21	21	18	16	14	15	17	20	23	24	26
(S,O)	61	26	21	21	18	16	15	15	18	20	23	24	26
(S,O)	62	26	22	22	19	16	15	16	18	20	23	25	26
(S,O)	63	27	22	22	19	17	15	16	18	21	24	25	27
(S,O)	64	27	22	22	19	17	15	16	18	21	24	26	27
(S,O)	65	28	23	23	20	17	15	16	19	21	24	26	28

(Cont'd on Sheet No. 32.3)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC BILLS RENDERED
ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 32.3**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF F.W. – S.L.
(Fort Wayne Streetlighting – Customer Owned and Maintained System)
(Cont'd from Sheet No. 32.2)

TYPE OF LAMP AND APPROXIMATE LUMENS[1]	TOTAL WATTS	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
(S,O)	66	28	23	23	20	17	16	17	19	22	25	26	28
(S,O)	67	29	24	24	20	18	16	17	19	22	25	27	29
(S,O)	68	29	24	24	20	18	16	17	20	22	26	27	29
(S,O)	69	29	24	24	21	18	16	17	20	22	26	28	29
(S,O)	70	30	25	25	21	18	17	18	20	23	26	28	30
(S,O)	71	30	25	25	21	19	17	18	20	23	27	28	30
(S,O)	72	31	25	25	22	19	17	18	21	23	27	29	31
(S,O)	73	31	26	26	22	19	17	18	21	24	27	29	31
(S,O)	74	32	26	26	22	19	18	19	21	24	28	30	32
(S,O)	75	32	26	26	23	20	18	19	22	24	28	30	32
(S,O)	76	32	27	27	23	20	18	19	22	25	29	30	32
(S,O)	77	33	27	27	23	20	18	19	22	25	29	31	33
(S,O)	78	33	27	27	23	21	19	20	22	25	29	31	33
(S,O)	79	34	28	28	24	21	19	20	23	26	30	32	34
(S,O)	80	34	28	28	24	21	19	20	23	26	30	32	34
(S,O)	81	35	28	28	24	21	19	20	23	26	30	33	35
(S,O)	82	35	29	29	25	22	20	21	24	27	31	33	35
(S,O)	83	35	29	29	25	22	20	21	24	27	31	33	35
(S,O)	84	36	29	29	25	22	20	21	24	27	32	34	36
(S,O)	85	36	30	30	26	22	20	21	25	28	32	34	36
(S,O)	86	37	30	30	26	23	20	22	25	28	32	35	37
(S,O)	87	37	31	31	26	23	21	22	25	28	33	35	37
(S,O)	88	38	31	31	26	23	21	22	25	29	33	35	38
(S,O)	89	38	31	31	27	23	21	22	26	29	33	36	38
(S,O)	90	38	32	32	27	24	21	23	26	29	34	36	38
(S,O)	91	39	32	32	27	24	22	23	26	30	34	37	39
(S,O)	92	39	32	32	28	24	22	23	27	30	35	37	39
(S,O)	93	40	33	33	28	24	22	23	27	30	35	37	40
(S,O)	94	40	33	33	28	25	22	24	27	31	35	38	40
(S,O)	95	41	33	33	29	25	23	24	27	31	36	38	41
(S,O)	96	41	34	34	29	25	23	24	28	31	36	39	41
(S,O)	97	41	34	34	29	26	23	24	28	32	36	39	41
(S,O)	98	42	34	34	29	26	23	25	28	32	37	39	42
(S,O)	99	42	35	35	30	26	24	25	29	32	37	40	42
(S,O)	100	43	35	35	30	26	24	25	29	33	38	40	43
(S,O)	101	43	35	35	30	27	24	25	29	33	38	41	43
(S,O)	102	43	36	36	31	27	24	26	29	33	38	41	43
(S,O)	103	44	36	36	31	27	25	26	30	34	39	41	44
(S,O)	104	44	37	37	31	27	25	26	30	34	39	42	44
(S,O)	105	45	37	37	32	28	25	26	30	34	39	42	45
(S,O)	106	45	37	37	32	28	25	27	31	35	40	43	45
(S,O)	107	46	38	38	32	28	25	27	31	35	40	43	46
(S,O)	108	46	38	38	33	28	26	27	31	35	41	43	46
(S,O)	109	46	38	38	33	29	26	27	31	36	41	44	46
(S,O)	110	47	39	39	33	29	26	28	32	36	41	44	47
(S,O)	111	47	39	39	33	29	26	28	32	36	42	45	47
(S,O)	112	48	39	39	34	29	27	28	32	37	42	45	48
(S,O)	113	48	40	40	34	30	27	28	33	37	43	45	48
(S,O)	114	49	40	40	34	30	27	29	33	37	43	46	49
(S,O)	115	49	40	40	35	30	27	29	33	37	43	46	49

(Cont'd on Sheet No. 32.4)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 32.4**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF F.W. – S.L.
(Fort Wayne Streetlighting – Customer Owned and Maintained System)
(Cont'd from Sheet No. 32.3)

TYPE OF LAMP AND APPROXIMATE LUMENS[1]	TOTAL WATTS	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
(S,O)	116	49	41	41	35	31	28	29	33	38	44	47	49
(S,O)	117	50	41	41	35	31	28	29	34	38	44	47	50
(S,O)	118	50	41	41	36	31	28	30	34	38	44	47	50
(S,O)	119	51	42	42	36	31	28	30	34	39	45	48	51
(S,O)	120	51	42	42	36	32	29	30	35	39	45	48	51
(S,O)	121	52	42	42	36	32	29	30	35	39	46	49	52
(S,O)	122	52	43	43	37	32	29	31	35	40	46	49	52
(S,O)	123	52	43	43	37	32	29	31	35	40	46	49	52
(S,O)	124	53	44	44	37	33	30	31	36	40	47	50	53
(S,O)	125	53	44	44	38	33	30	31	36	41	47	50	53
(S,O)	126	54	44	44	38	33	30	32	36	41	47	51	54
(S,O)	127	54	45	45	38	33	30	32	37	41	48	51	54
(S,O)	128	55	45	45	39	34	30	32	37	42	48	51	55
(S,O)	129	55	45	45	39	34	31	32	37	42	49	52	55
(S,O)	130	55	46	46	39	34	31	33	37	42	49	52	55
(S,O)	131	56	46	46	39	34	31	33	38	43	49	53	56
(S,O)	132	56	46	46	40	35	31	33	38	43	50	53	56
(S,O)	133	57	47	47	40	35	32	33	38	43	50	53	57
(S,O)	134	57	47	47	40	35	32	34	39	44	50	54	57
(S,O)	135	58	47	47	41	36	32	34	39	44	51	54	58
(S,O)	136	58	48	48	41	36	32	34	39	44	51	55	58
(S,O)	137	58	48	48	41	36	33	34	40	45	52	55	58
(S,O)	138	59	48	48	42	36	33	35	40	45	52	55	59
(S,O)	139	59	49	49	42	37	33	35	40	45	52	56	59
(S,O)	140	60	49	49	42	37	33	35	40	46	53	56	60
(S,O)	141	60	50	50	42	37	34	35	41	46	53	57	60
(S,O)	142	61	50	50	43	37	34	36	41	46	53	57	61
(S,O)	143	61	50	50	43	38	34	36	41	47	54	57	61
(S,O)	144	61	51	51	43	38	34	36	42	47	54	58	61
(S,O)	145	62	51	51	44	38	35	36	42	47	55	58	62
(S,O)	146	62	51	51	44	38	35	37	42	48	55	59	62
(S,O)	147	63	52	52	44	39	35	37	42	48	55	59	63
(S,O)	148	63	52	52	45	39	35	37	43	48	56	59	63
(S,O)	149	64	52	52	45	39	35	37	43	49	56	60	64
(S,O)	150	64	53	53	45	39	36	38	43	49	56	60	64
(S,O)	151	64	53	53	45	40	36	38	44	49	57	61	64
(S,O)	152	65	53	53	46	40	36	38	44	50	57	61	65
(S,O)	153	65	54	54	46	40	36	38	44	50	58	61	65
(S,O)	154	66	54	54	46	41	37	39	44	50	58	62	66
(S,O)	155	66	54	54	47	41	37	39	45	51	58	62	66
(S,O)	156	67	55	55	47	41	37	39	45	51	59	63	67
(S,O)	157	67	55	55	47	41	37	39	45	51	59	63	67
(S,O)	158	67	55	55	48	42	38	40	46	52	59	63	67
(S,O)	159	68	56	56	48	42	38	40	46	52	60	64	68
(S,O)	160	68	56	56	48	42	38	40	46	52	60	64	68
(S,O)	161	69	57	57	48	42	38	40	46	52	61	65	69
(S,O)	162	69	57	57	49	43	38	41	47	53	61	65	69
(S,O)	163	69	57	57	49	43	39	41	47	53	61	65	69
(S,O)	164	70	58	58	49	43	39	41	47	53	62	66	70
(S,O)	165	70	58	58	50	43	39	41	48	54	62	66	70

(Cont'd on Sheet No. 32.5)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 32.5**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF F.W. – S.L.
(Fort Wayne Streetlighting – Customer Owned and Maintained System)
(Cont'd from Sheet No.32.4)

TYPE OF LAMP AND APPROXIMATE LUMENS[1]	TOTAL WATTS	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
(S,O)	166	71	58	58	50	44	40	42	48	54	62	67	71
(S,O)	167	71	59	59	50	44	40	42	48	54	63	67	71
(S,O)	168	72	59	59	51	44	40	42	48	55	63	67	72
(S,O)	169	72	59	59	51	45	40	42	49	55	64	68	72
(S,O)	170	72	60	60	51	45	41	43	49	55	64	68	72
(S,O)	171	73	60	60	51	45	41	43	49	56	64	69	73
(S,O)	172	73	60	60	52	45	41	43	50	56	65	69	73
(S,O)	173	74	61	61	52	46	41	43	50	56	65	69	74
(S,O)	174	74	61	61	52	46	41	44	50	57	65	70	74
(S,O)	175	75	61	61	53	46	42	44	50	57	66	70	75
(S,O)	176	75	62	62	53	46	42	44	51	57	66	71	75
(S,O)	177	75	62	62	53	47	42	44	51	58	67	71	75
(S,O)	178	76	62	62	54	47	42	45	51	58	67	71	76
(S,O)	179	76	63	63	54	47	43	45	52	58	67	72	76
(S,O)	180	77	63	63	54	47	43	45	52	59	68	72	77
(S,O)	181	77	64	64	54	48	43	45	52	59	68	73	77
(S,O)	182	78	64	64	55	48	43	46	52	59	68	73	78
(S,O)	183	78	64	64	55	48	44	46	53	60	69	73	78
(S,O)	184	78	65	65	55	48	44	46	53	60	69	74	78
(S,O)	185	79	65	65	56	49	44	46	53	60	70	74	79
(S,O)	186	79	65	65	56	49	44	47	54	61	70	75	79
(S,O)	187	80	66	66	56	49	45	47	54	61	70	75	80
(S,O)	188	80	66	66	57	50	45	47	54	61	71	75	80
(S,O)	189	81	66	66	57	50	45	47	55	62	71	76	81
(S,O)	190	81	67	67	57	50	45	48	55	62	71	76	81
(S,O)	191	81	67	67	57	50	46	48	55	62	72	77	81
(S,O)	192	82	67	67	58	51	46	48	55	63	72	77	82
(S,O)	193	82	68	68	58	51	46	48	56	63	73	77	82
(S,O)	194	83	68	68	58	51	46	49	56	63	73	78	83
(S,O)	195	83	68	68	59	51	46	49	56	64	73	78	83
(S,O)	196	84	69	69	59	52	47	49	57	64	74	79	84
(S,O)	197	84	69	69	59	52	47	49	57	64	74	79	84
(S,O)	198	84	70	70	60	52	47	50	57	65	74	79	84
(S,O)	199	85	70	70	60	52	47	50	57	65	75	80	85
(S,O)	200	85	70	70	60	53	48	50	58	65	75	80	85
(S,O)	201	86	71	71	60	53	48	50	58	66	76	81	86
(S,O)	202	86	71	71	61	53	48	51	58	66	76	81	86
(S,O)	203	87	71	71	61	53	48	51	59	66	76	81	87
(S,O)	204	87	72	72	61	54	49	51	59	67	77	82	87
(S,O)	205	87	72	72	62	54	49	51	59	67	77	82	87
(S,O)	206	88	72	72	62	54	49	52	59	67	77	83	88
(S,O)	207	88	73	73	62	55	49	52	60	67	78	83	88
(S,O)	208	89	73	73	63	55	50	52	60	68	78	83	89
(S,O)	209	89	73	73	63	55	50	52	60	68	79	84	89
(S,O)	210	90	74	74	63	55	50	53	61	68	79	84	90
(S,O)	211	90	74	74	63	56	50	53	61	69	79	85	90
(S,O)	212	90	74	74	64	56	51	53	61	69	80	85	90
(S,O)	213	91	75	75	64	56	51	53	61	69	80	85	91
(S,O)	214	91	75	75	64	56	51	54	62	70	81	86	91
(S,O)	215	92	75	75	65	57	51	54	62	70	81	86	92

(Cont'd on Sheet No. 32.6)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC BILLS RENDERED
ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 32.6**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF F.W. – S.L.
(Fort Wayne Streetlighting – Customer Owned and Maintained System)
(Cont'd from Sheet No. 32.5)

TYPE OF LAMP AND APPROXIMATE LUMENS[1]	TOTAL WATTS	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
(S,O)	216	92	76	76	65	57	51	54	62	70	81	87	92
S,O)	217	93	76	76	65	57	52	54	63	71	82	87	93
(S,O)	218	93	77	77	66	57	52	55	63	71	82	87	93
(S,O)	219	93	77	77	66	58	52	55	63	71	82	88	93
(S,O)	220	94	77	77	66	58	52	55	63	72	83	88	94
(S,O)	221	94	78	78	67	58	53	55	64	72	83	89	94
(S,O)	222	95	78	78	67	58	53	56	64	72	84	89	95
(S,O)	223	95	78	78	67	59	53	56	64	73	84	89	95
(S,O)	224	95	79	79	67	59	53	56	65	73	84	90	95
(S,O)	225	96	79	79	68	59	54	56	65	73	85	90	96
(S,O)	226	96	79	79	68	60	54	57	65	74	85	91	96
(S,O)	227	97	80	80	68	60	54	57	65	74	85	91	97
(S,O)	228	97	80	80	69	60	54	57	66	74	86	91	97
(S,O)	229	98	80	80	69	60	55	57	66	75	86	92	98
(S,O)	230	98	81	81	69	61	55	58	66	75	87	92	98
(S,O)	231	98	81	81	70	61	55	58	67	75	87	93	98
(S,O)	232	99	81	81	70	61	55	58	67	76	87	93	99
(S,O)	233	99	82	82	70	61	56	58	67	76	88	93	99
(S,O)	234	100	82	82	70	62	56	59	67	76	88	94	100
(S,O)	235	100	83	83	71	62	56	59	68	77	88	94	100
(S,O)	236	101	83	83	71	62	56	59	68	77	89	95	101
(S,O)	237	101	83	83	71	62	56	59	68	77	89	95	101
(S,O)	238	101	84	84	72	63	57	60	69	78	90	95	101
(S,O)	239	102	84	84	72	63	57	60	69	78	90	96	102
(S,O)	240	102	84	84	72	63	57	60	69	78	90	96	102
(S,O)	241	103	85	85	73	63	57	60	70	79	91	97	103
(S,O)	242	103	85	85	73	64	58	61	70	79	91	97	103
(S,O)	243	104	85	85	73	64	58	61	70	79	91	98	104
(S,O)	244	104	86	86	73	64	58	61	70	80	92	98	104
(S,O)	245	104	86	86	74	65	58	61	71	80	92	98	104
(S,O)	246	105	86	86	74	65	59	62	71	80	93	99	105
(S,O)	247	105	87	87	74	65	59	62	71	81	93	99	105
(S,O)	248	106	87	87	75	65	59	62	72	81	93	100	106
(S,O)	249	106	87	87	75	66	59	62	72	81	94	100	106
(S,O)	250	107	88	88	75	66	60	63	72	82	94	100	107
(S,O)	251	107	88	88	76	66	60	63	72	82	94	101	107
(S,O)	252	107	88	88	76	66	60	63	73	82	95	101	107
(S,O)	253	108	89	89	76	67	60	63	73	82	95	102	108
(S,O)	254	108	89	89	76	67	61	64	73	83	96	102	108
(S,O)	255	109	90	90	77	67	61	64	74	83	96	102	109
(S,O)	256	109	90	90	77	67	61	64	74	83	96	103	109
(S,O)	257	110	90	90	77	68	61	64	74	84	97	103	110
(S,O)	258	110	91	91	78	68	61	65	74	84	97	104	110
(S,O)	259	110	91	91	78	68	62	65	75	84	97	104	110
(S,O)	260	111	91	91	78	68	62	65	75	85	98	104	111
(S,O)	261	111	92	92	79	69	62	65	75	85	98	105	111
(S,O)	262	112	92	92	79	69	62	66	76	85	99	105	112
(S,O)	263	112	92	92	79	69	63	66	76	86	99	106	112
(S,O)	264	113	93	93	79	70	63	66	76	86	99	106	113
(S,O)	265	113	93	93	80	70	63	66	76	86	100	106	113

(Cont'd on Sheet No. 32.7)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 32.7**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF F.W. – S.L.
(Fort Wayne Streetlighting – Customer Owned and Maintained System)
(Cont'd from Sheet No. 32.6)

TYPE OF LAMP AND APPROXIMATE LUMENS[1]	TOTAL WATTS	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
(S,O)	266	113	93	93	80	70	63	67	77	87	100	107	113
(S,O)	267	114	94	94	80	70	64	67	77	87	100	107	114
(S,O)	268	114	94	94	81	71	64	67	77	87	101	108	114
(S,O)	269	115	94	94	81	71	64	67	78	88	101	108	115
(S,O)	270	115	95	95	81	71	64	68	78	88	102	108	115
(S,O)	271	116	95	95	82	71	65	68	78	88	102	109	116
(S,O)	272	116	95	95	82	72	65	68	78	89	102	109	116
(S,O)	273	116	96	96	82	72	65	68	79	89	103	110	116
(S,O)	274	117	96	96	82	72	65	69	79	89	103	110	117
(S,O)	275	117	97	97	83	72	66	69	79	90	103	110	117
(S,O)	276	118	97	97	83	73	66	69	80	90	104	111	118
(S,O)	277	118	97	97	83	73	66	69	80	90	104	111	118
(S,O)	278	119	98	98	84	73	66	70	80	91	105	112	119
(S,O)	279	119	98	98	84	73	66	70	80	91	105	112	119
(S,O)	280	119	98	98	84	74	67	70	81	91	105	112	119
(S,O)	281	120	99	99	85	74	67	70	81	92	106	113	120
(S,O)	282	120	99	99	85	74	67	71	81	92	106	113	120
(S,O)	283	121	99	99	85	75	67	71	82	92	106	114	121
(S,O)	284	121	100	100	85	75	68	71	82	93	107	114	121
(S,O)	285	122	100	100	86	75	68	71	82	93	107	114	122
(S,O)	286	122	100	100	86	75	68	72	82	93	108	115	122
(S,O)	287	122	101	101	86	76	68	72	83	94	108	115	122
(S,O)	288	123	101	101	87	76	69	72	83	96	108	116	123
(S,O)	289	123	101	101	87	76	69	72	83	94	109	116	123
(S,O)	290	124	102	102	87	76	69	73	84	95	109	116	124
(S,O)	291	124	102	102	88	77	69	73	84	95	109	117	124
(S,O)	292	124	103	103	88	77	70	73	84	95	110	117	124
(S,O)	293	125	103	103	88	77	70	73	85	96	110	118	125
(S,O)	294	125	103	103	88	77	70	74	85	96	111	118	125
(S,O)	295	126	104	104	89	78	70	74	85	96	111	118	126
(S,O)	296	126	104	104	89	78	71	74	85	97	111	119	126
(S,O)	297	127	104	104	89	78	71	74	86	97	112	119	127
(S,O)	298	127	105	105	90	78	71	75	86	97	112	120	127
(S,O)	299	127	105	105	90	79	71	75	86	97	112	120	127
(S,O)	300	128	105	105	90	79	71	75	87	98	113	120	128

NOTE: For half-night (time clock) lamps multiply consumption by 0.5 or for a 7-hour timer multiply by 0.63875.
[1]Lumen Output for Mercury Vapor, Sodium Vapor, and Metal Halide listed in this table as mean lumens in first column and initial lumens in the second column. Lumen rating varies with lamp manufacturer.
[2]City of Fort Wayne, IN only.

Special Terms and Conditions.

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

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

TARIFF I.S.
(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.

Rate. (Tariff Code 213)

Energy Charge: 16.667 ~~19.20~~ ¢ per kWh

Minimum Charge.

This tariff is subject to a minimum monthly charge equal to the monthly service charge.

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

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.

Special Terms and Conditions.

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

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.

Customers with cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP or by special agreement with the Company.

TARIFF COGEN/SPP
(Cogeneration and/or Small Power Production Service)

Availability of Service.

This schedule is available to customers with cogeneration and/or small power production (COGEN/SPP) facilities which qualify under Section 210 of the Public Utilities Regulatory Policies Act of 1978 and have a total design capacity of 100 kW or less. 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 on-peak 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 on-peak 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.

(Cont'd on Sheet No. 34.1)

TARIFF COGEN/SPP
(Cogeneration and/or Small Power Production Service)
(Cont'd from Sheet No. 34)

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.

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.

A monthly service charge of $ 0.432 per kilowatt of backup capacity shall be paid by customers served under demand-metered rate schedules. 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.

(Cont'd on Sheet No. 34.2)

TARIFF COGEN/SPP
(Cogeneration and/or Small Power Production Service)

(Cont'd from Sheet No. 34.1)

Additional Charges.

There shall be additional 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) Metering Charges

The additional charge for special metering facilities shall be as follows:

(a) Option 1

Where the customer does not sell electricity to the Company, a detent shall be used on the energy meter to prevent reverse rotation. The cost of such meter alteration shall be paid by the customer as part of the Local Facilities Charge.

(b) Options 2 & 3

Where energy meters are required to measure the excess energy and average on-peak capacity purchased by the Company or the total energy and average on-peak capacity produced by the customer's COGEN/SPP facilities, the cost of the additional metering facilities shall be paid by the customer as part of the Local Facilities Charge. In addition, a monthly metering charge shall be as follows to cover the cost of operation and maintenance of such additional facilities:

	Single Phase	Polyphase
Standard Measurement	$ 1.05	$ 1.05
TOD Measurement	$ 1.05	$ 1.30

Under Option 3, when metering voltage for COGEN/SPP facilities is the same as the Company's delivery voltage, 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 which will enable the Company to measure adequately the total electrical energy and average on-peak capacity produced by the qualifying COGEN/SPP facilities, as well as to measure the electrical energy consumption and capacity

(Cont'd on Sheet No. 34.3)

TARIFF COGEN/SPP
(Cogeneration and/or Small Power Production Service)

(Cont'd from Sheet No. 34.2)

requirements of the customer's total load. When metering voltage for COGEN/SPP facilities is different from the Company's delivery voltage, metering requirements and charges shall be determined specifically for each case.

(2) Local Facilities Charge.

Additional charges to cover the cost of special metering facilities, 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, 12 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 Energy and Capacity Deliveries.

(1) Energy Credit

The following credits or payments from the Company to the customer shall apply for the electrical energy delivered to the Company:

Standard Meter	
All kWh	2.83¢
TOD Meter	
On-peak kWh	3.45¢
Off-peak kWh	2.39¢

(2) Capacity Credit

If the customer contracts to deliver a specified average capacity during the on-peak monthly billing period (on-peak contract capacity), then the first-year monthly capacity credit or payment from the Company to the customer shall be \$ 5.29/kW times the lowest of:

(a) monthly on-peak contract capacity, or

(b) current month on-peak metered average capacity, i.e., on-peak kWh delivered to the Company divided by 305, or

(Cont'd on Sheet No. 34.4)

TARIFF COGEN/SPP
(Cogeneration and/or Small Power Production Service)

(Cont'd from Sheet No. 34.3)

(c) lowest on-peak average capacity metered during the previous two months.

Determination of the monthly capacity credits or payments for subsequent years of the contract term shall be made using the formula contained in 170 IAC 4-4.1.

The above energy and capacity credit rates are subject to annual revision as required by the Commission.

On-Peak and Off-Peak Hours.

The on-peak period shall be defined as starting 7 a.m. and ending at 9 p.m., local time, Monday through Friday.

The off-peak period shall be defined as starting at 9 p.m. and ending at 7 a.m., local time, Monday through Friday, and all hours of Saturday and Sunday.

Charges for Cancellation or Non-Performance of Contract.

In the event the contract is terminated or the contract capacity is reduced prior to the end of the contract term, the qualifying COGEN/SPP facility shall refund to the Company the capacity payments in excess of those capacity payments which would have been made had all or the reduced capacity been subject to a capacity rate based on the actual term of delivery to the Company.

Except in the event of force majeure as defined in the contract, if within any 12-month period during the term of the contract ending on the anniversary date of the date of the qualifying COGEN/SPP facility first provided capacity to the Company under the contract the qualifying COGEN/SPP facility fails to provide the Company with the capacity specified in the contract, the capacity for which the qualifying COGEN/SPP facility shall be entitled to capacity payments during the subsequent 12-month period ("the probationary period") shall be reduced to the capacity provided during the prior 12-month period. If during the probationary period the qualifying COGEN/SPP facility provides the capacity specified in the contract, the Company, within 30 days following the end of the probationary period, shall reinstate the full capacity amount originally specified in the contract. If during the probationary period the qualifying COGEN/SPP facility again fails to provide the capacity specified in the contract, the Company may permanently reduce the capacity purchased from the qualifying COGEN/SPP facility for the remainder of the term of the contract. The Company may also require that the reduction in the capacity be subject to the refund provisions of the above paragraph.

Terms of Contract.

Contracts under this tariff will be made for a period not less than one year nor more than five years.

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 March 23, 2009 or existing AFS customers that desire to maintain redundant service when the Company must make expenditures in order to continue providing such service or July 1, 2023, whichever occurs first.

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.G.S.-TOD, I.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.

(Cont'd on Sheet No. 35.1)

RIDER AFS
(Alternate Feed Service)

(Cont'd from Sheet No. 35)

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, 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 $16.30 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.

(Cont'd on Sheet No. 35.2)

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 35.2

RIDER AFS
(Alternate Feed Service)

(Cont'd from Sheet No. 35.1)

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 $4.730 ~~5.096~~ per kW~~kVA~~.

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.

(Cont'd on Sheet No. 35.3)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

RIDER AFS
(Alternate Feed Service)

(Cont'd from Sheet No. 35.2)

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 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.

All bills under this rider shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3 there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3. Any governmental agency whose basic service is provided under Tariffs M.S. or W.S.S. 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.

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.

(Cont'd on Sheet No. 35.4)

RIDER AFS
(Alternate Feed Service)

(Cont'd from Sheet No. 35.3)

Special Terms and Conditions.

This rider is subject to the Company's Terms and Conditions of 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.

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 36**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

RIDER D.R.S.1
(Demand Response Service – Emergency)

Availability of Service.

Available for demand response service (DRS) to customers in good standing, as determined by the Company, taking firm service from the Company under Tariffs G.S., G.S.-TOD, L.G.S., L.G.S.-TOD, I.P., M.S., W.S.S., or E.H.G. who have the ability to curtail load under the provisions under this Rider. Each customer electing service under this Rider shall contract for a definite amount of DRS capacity, not to exceed the customer's normal demand capable of being curtailed.

The Company reserves the right to limit the aggregate amount of DRS capacity contracted for under this Rider and Tariff C.S.-IRP2 to 235 MWVAW. The Company will take DRS requests in the order received. The customer's DRS capacity under this Rider will be enrolled in the PJM Interconnection, L.L.C. RTO (PJM) Emergency Demand Response Program through the Company. The Company further reserves the right to limit registrations should PJM restrict the Company from registering customers in any PJM product type. The customer's DRS capacity is not eligible for enrollment in any PJM demand response program either directly or through a Curtailment Service Provider (CSP). Customer's participating in this Rider may elect to use the services of a CSP provided that such arrangements do not violate the terms and conditions of this Rider.

A CSP is an entity such as a PJM-qualified CSP that the customer has designated to facilitate all or some of the customer notifications and transactions under this Rider.

The customer must provide written notice to the Company of any such designation. Such written notice shall specify the authority that the customer has granted to the CSP, including any authority to access customer data. The customer is ultimately responsible for compliance with the terms and conditions of this Rider, including any charges under this Rider, in which the customer has voluntarily elected to participate.

The term "customer" as used herein shall mean the customer or an aggregation of customers that have agreed for purposes of participation in the Rider to participate as an aggregation in the same manner as a single customer would under this Rider. The term "participant" as used herein shall mean the customer or customer-designated CSP as defined above.

Conditions of Service.

(1) The provisions of this Rider qualify under the PJM Emergency Demand Response Program as of the effective date. The Company reserves the right to make changes to this Rider in order to continue to qualify under the PJM Emergency Demand Response Program, or otherwise, as appropriate.
(2) The Company reserves the right to call for (request) customers to curtail their DRS load when a Pre-Emergency and/or Emergency Mandatory Load Management Reduction Action has been issued by PJM.
(3) The Company will endeavor to provide as much advance notice as possible of curtailments under this Rider including an estimate of the duration of such curtailments. However, the customer's DRS load shall be curtailed within 15 minutes if so requested.
(4) All curtailments will apply for the delivery year (DY) which is defined by PJM as June 1 through May 31 of the following year. Contracts will apply for multiple delivery years.

(Cont'd on Sheet No. 36.1)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 36.1**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

RIDER D.R.S.1
(Demand Response Service – Emergency)

(Cont'd from Sheet No. 36)

(5) In no event shall the customer be subject to PJM initiated load curtailment (PJM event) under the provisions of this Rider for more than the amount designated under the DRS Product Type Option selected by customer during delivery year. The customer must agree to be subject to DRS curtailments pursuant to the DRS Product Type Option selected by customer from the DRS Product Type Option table herein.

(6) The Company will inform the participant regarding the communication process for notices to curtail. The customer is ultimately responsible for receiving and acting upon a curtailment notification from the Company. The customer is not responsible in the event the Company fails to properly issue a curtailment notification.

(7) All customer metering demand data required under this Rider shall be determined from 15-minute integrated metering with remote interrogation capability and demand recording equipment owned, installed, operated and maintained by the Company. When required, the Company will install such metering equipment for individual accounts contracting for 50 kW or more at no cost to the customer and for accounts contracting for less than 50 kW, a fee of $750.00 paid in advance shall be required.

(8) During each delivery year the Company will conduct a test and verify the customer's ability to curtail as required by PJM. However, if a curtailment event is called by PJM prior to the test, then the event shall be considered the test for the delivery year. The Company reserves the right to re-test all customers if the Company does not achieve the minimum 75% compliance testing standards for all of the Company's DRS customers as required by PJM. Additionally, the Company reserves the right to retest individual customers, and/or aggregated groups, that fail to comply during a test. These tests must be conducted for one hour on a weekday between 12 noon and 8 p.m., Eastern Time, from June 1 through September 30 during the delivery year.

(9) If the customer fails to comply with the provisions of curtailment under this Rider, including the test provisions as indicated above, the Company and the customer will discuss methods to comply during future events. If the problem cannot be resolved to the Company's satisfaction, the Company reserves the right to adjust the customer's committed kW amount or discontinue service to the customer under this Rider. Such adjustments or terminations will be charged as outlined under the Annual Non-Compliance Charge provision.

(10) The minimum DRS capacity contracted for under this Rider will be 100 kW. Customers with multiple electric service accounts may aggregate those individual accounts to meet the 100 kW minimum DRS capacity requirement under this Rider; however, the DRS capacity committed for each individual account shall not be less than 25 kW and no more than one site may be 100 kW or greater. Aggregation with multiple individual electric service accounts, not under common ownership, must designate a PJM qualified CSP who shall be responsible to facilitate all of the customer notifications and transactions under this Rider. A CSP that creates an aggregation may provide to the Company both a Registered kW and Committed kW amount of such aggregation. The Registered kW represents

(Cont'd on Sheet No. 36.2)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
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DATED
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I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 36.2

RIDER D.R.S.1
(Demand Response Service – Emergency)

(Cont'd from Sheet No. 36.1)

the amount of Curtailed Demand CSP desires the Company to register with PJM. The Committed kW shall be the amount of Curtailed Demand that is the basis upon which participants are paid under this Rider. Registered kW shall be equal to or greater than Committed kW. Committed kW shall not exceed the Registered kW.

(11) In addition to curtailments under Item 2 above, the Company reserves the right to call for (request) customers to curtail their DRS load when, in the sole judgment of the Company, an emergency condition exists on the American Electric Power (AEP) System. The Company shall determine that an emergency condition exists if curtailment of load served under this Rider is necessary in order to maintain service to the Company's other firm service customers according to the AEP System Emergency Operating Plan. During such event, the customer must make best efforts to voluntarily curtail DRS load.

(12) **NO RESPONSIBILITY OR LIABILITY OF ANY KIND SHALL ATTACH TO OR BE INCURRED BY THE COMPANY OR THE AEP SYSTEM FOR, OR ON ACCOUNT OF, ANY LOSS, COST, EXPENSE, OR DAMAGE CAUSED BY OR RESULTING FROM, EITHER DIRECTLY OR INDIRECTLY, ANY CURTAILMENT OF SERVICE UNDER THE PROVISIONS OF THIS RIDER.**

(Cont'd on Sheet No. 36.3)

RIDER D.R.S.1
(Demand Response Service – Emergency)
(Cont'd from Sheet No. 36.2)

DRS Product Type Options and Curtailment Demand Payment.

The Curtailment Demand Payment shall be calculated in $ per kW-month as the greater of (a) the four-year average RPM Clearing price for the applicable locational delivery area and product type, calculated using the preceding delivery year, the delivery year and the subsequent two (2) delivery years and (b) 35% of the applicable PJM Reliability Pricing Model (RPM) Net Cost of New Entry (Net CONE) for the delivery year.

Capacity Performance Demand Resource - DRS Product

Product Type	Curtailment Availability	Maximum Number of Curtailments	Hours of Day to Respond	Maximum Duration of Curtailments	2021 / 2022 DY Curtailment Demand Payment $ / kW per Month
Capacity Performance Demand Resource (Effective 2021 / 2022 DY)	Any Day during DY (unless on an approved maint. outage during Oct-April)	Unlimited	June – Oct and following May of DY (10 am-10 pm) Nov-April (6am – 9 pm)	12 Hours 15 Hours	$3.66

The Capacity Performance Demand Resource above is the only DRS1 product option beginning June 1, 2020.

(Cont'd on Sheet No. 36.4)

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO.36.4

RIDER D.R.S.1
(Demand Response Service – Emergency)

(Cont'd from Sheet No. 36.3)

Behind the Meter Generation.

Participating customers who operate Behind the Meter Generation (BTMG) for demand response purposes under this Rider shall adhere to PJM rules governing the use of BTMG, and operate and be in compliance with all local, state and federal laws including environmental permits. Adherence and compliance with PJM rules and all local, state and federal laws with regard to BTMG is the sole responsibility of the customer.

Exception to 15-Minute Notification to Curtail DRS Load.

Customers will be required to fully respond to curtailment requests within 15-minutes of notification from the Company unless an exception request has been approved by PJM. The qualifying exceptions as defined by PJM are listed directly below. The intent of these qualifying exceptions is to accommodate DRS customers with legitimate, physical reasons that prevent curtailing load within a 15-minute notification time period.

PJM Qualifying Exception Definitions:

1) Damage (feedstock/equipment/product) - unavoidable significant damage to feedstock, equipment or product.

2) Generator Ramp time - Transfer of load to back-up generation requires taking more than 15-minutes.

3) Safety Issue - On-site safety concerns prevent location from implementing reduction plan in less than 15-minutes.

Customers desiring to be considered for one of the above qualifying exceptions shall complete an Exception Request Form, provided by the Company upon request. Company will submit any completed form to PJM for consideration and approval. Company will notify customer of PJM's approval/denial decision and if approved what the approved notification time period will be for the next delivery year. PJM may require customers to apply for an exemption prior to each delivery year.

Customer Baseline Load Calculation.

A Customer Baseline Load (CBL) will be calculated for each hour corresponding to each curtailment event hour. Normally, the CBL will be calculated for each hour as the average corresponding hourly demands from the highest four (4) out of the five (5) most recent similar non-event days in the period preceding the relevant curtailment event. The highest load days are defined as the similar days (Weekday, Saturday, Sunday/Holiday as defined by PJM) with the highest energy consumption spanning the curtailment event hours. In cases where the normal calculation does not provide a reasonable representation of normal load conditions, the Company and the participant may develop an alternative CBL calculation that more accurately reflects the customer's normal consumption pattern.

(Cont'd on Sheet No. 36.5)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

RIDER D.R.S.1
(Demand Response Service – Emergency)

(Cont'd from Sheet No. 36.4)

Curtailed Demand.

The customer's Curtailed Demand shall be determined based upon the method of measurement chosen by the customer. The customer may choose one of two methods to measure the curtailed demand: 1) Guaranteed Load Drop (GLD), or 2) Firm Service Level (FSL). The method chosen shall remain in effect for the entire contract period.

(1) Guaranteed Load Drop Method.

(a) Each customer must designate a Guaranteed Load Drop (GLD), which amount shall be the minimum demand reduction that the customer will provide for each hour during a curtailment event or during a curtailment test. The customers GLD can not be greater than the customers Peak Load Contribution (PLC), as defined below. GLD shall be adjusted to include losses.

(b) If the customer fails to fully comply with a request for curtailment under the provisions of this Rider or does not reduce load by the full GLD, a non-compliance charge shall apply. For this purpose, Actual Load Drop (ALD) is defined as the difference between the customer's CBL and their actual hourly load. If the ALD is less than the GLD, the Event Non-Compliance Demand shall be equal to the average difference between the GLD and the ALD occurring during the hours of the curtailment event. Otherwise, the Event Non-Compliance Demand shall be zero (0).

(2) Seasonal Firm Service Level (FSL) Method.

(a) The annual Load Management (DR) nomination is the lessor of the Winter / Summer nominated capacity. Firm Service Level Peak Load Contribution (PLC) – The customer's PLC's will be calculated each year. Summer PLC as the average of its load during PJM's five (5) highest peak loads during the twelve month period ended October 31 of the previous year. Winter PLC will be calculated as PJM's five (5) highest peak loads during December – February and actual calculations are performed by PJM. In the cases where the normal calculation does not provide a reasonable representation of normal load conditions, the Company and the customer may develop an alternative PLC calculation that more accurately reflects the customer's normal consumption pattern. PLC shall include losses.

(b) Available Curtailable Demand (ACD) - The customer must designate an ACD, defined as the difference between the PLC and the seasonal Firm Service Level (FSL). The FSL is the demand to which the customer agrees to reduce load to or below for each hour during a curtailment event and designated as Winter or Summer. FSL shall be adjusted to include losses.

(c) If the customer fails to fully comply with a request for curtailment under the provisions of this Rider, then the Non-Compliance Charge shall apply. If a customer is operating at or below their designated FSL during an event, it will be understood that they have no DRS capacity available with which to comply and will not be charged a non-compliance penalty. If the metered demand

(Cont'd on Sheet No. 36.6)

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 36.6

RIDER D.R.S.1
(Demand Response Service – Emergency)

(Cont'd from Sheet No. 36.5)

during the curtailment event is above the FSL, the Event Non-Compliance Demand shall be equal to the average difference between the customer's metered demand and the FSL during all full 15-minute intervals of the curtailment event. Otherwise, the Event Non-Compliance Demand shall be zero (0).

For the Capacity Performance Demand Resource product, if the metered demand during the curtailment event is above the FSL, the Event Non-Compliance Energy shall be equal to the cumulative amount by which the customer's metered demand exceeds the FSL during all full 15-minute intervals of the curtailment event.

Curtailed Energy.

The Curtailed Energy shall be determined for each curtailment event hour, defined as the difference between the customer's CBL for that hour and the customer's metered load for that hour.

Curtailment Payment.

The Curtailment Energy Payment shall be 90% of the Indiana Michigan Power Company pricing point (AEPIM_RESID_AGG) of the AEP Load Zone hourly Real-Time Locational Marginal Price (LMP), or successor pricing point, as established by PJM (including congestion and marginal losses) for each curtailment event hour.

The Curtailment Demand Payment shall be as shown under section DRS Product Type Options and Curtailment Demand Payment.

Monthly Demand Payment.

The Monthly Demand Payment shall be applicable to each month the customer is served under this Rider, regardless of whether or not there are any curtailment events during the month.

1. Guaranteed Load Drop Method – The Monthly Demand Payment shall be equal to the product of the GLD and the Curtailment Demand Payment.
2. Firm Service Level (FSL) Method – The Monthly Demand Payment shall be equal to the product of the ACD and the Curtailment Demand Payment.

The Company reserves the right to withhold Monthly Demand Payments from any customer who is indebted to the Company for any service rendered at any location contracted under this Rider. If the customer's indebtedness to the Company has not been resolved by May 31 of the current delivery year, all Monthly Demand payments outstanding shall be forfeited.

(Cont'd on Sheet No. 36.7)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

RIDER D.R.S.1
(Demand Response Service – Emergency)

(Cont'd from Sheet No. 36.6)

Monthly Event Payment.

An Event Payment shall be calculated for each event hour equal to the product of the Curtailed Energy for that hour and the Curtailment Energy Payment for that hour. The Monthly Event Payment shall be the sum of the hourly Event Payments for all events occurring in the calendar month, but shall not exceed the portion of the customer's monthly bill that is computed on a per kWh basis under the applicable Standard Rider for the same billing month. The customer shall not receive Event Payment for any curtailment events to the extent that the customer's DRS capacity is already reduced due to a planned or unplanned outage as a result of vacation, renovation, repair, refurbishment, force majeure, strike, economic conditions, or any situation other than the customer's normal operating conditions. Event Payments will not be withheld if the customer's DRS capacity is already reduced as a result of customer actions taken in anticipation of a curtailment.

Annual Non-Compliance Charge for Capacity Performance Resource Product.

Beginning on June 1, 2018, the non-compliance charge will be based on the AEP, or successor, Locational Deliverability Area yearly Net CONE with a divisor of 30 (emergency action hours per year). The Non-Compliance Rate in $/MWh will be equal to the product of Net CONE ($/MW-day) as published by PJM and the number of days in the delivery year (365 or 366) divided by 30. The Monthly Non-Compliance Charge shall be equal to the product of the Non-Compliance Energy and the Non-Compliance Rate. The sum of the Monthly Non-Compliance Charges may exceed the sum of customer's monthly Demand Credits for the delivery year.

(Cont'd on Sheet No. 36.8)

RIDER D.R.S.1
(Demand Response Service – Emergency)

(Cont'd from Sheet No. 36.7)

Settlement.

The net amount of the Monthly Demand Payment, Monthly Energy Event Payment and Annual Non-Compliance Charge will be provided to the participant by check or electronic payment within 60 days after the end of the delivery month. A customer may request the aggregation of individual customer account payments into a single payment.

Term.

Contracts under this Rider shall be made for an initial period of four (4) delivery years and shall remain in effect until either party provides three (3) years' written notice prior to March 1 of its intention to discontinue service under the terms of this Rider for the fourth delivery year beginning after the notice is provided. Written notice deadlines through March 1, 2023 are as follows:

Written Notice Deadline	Effective Date of End of Service under Rider
March 1, 2022	June 1, 2025
March 1, 2023	June 1, 2026
March 1, 2024	June 1, 2027
March 1, 2025	June 1, 2028

If a customer becomes ineligible for service under this Rider during the term of a contract under this Rider, the Company reserves the right to terminate such contract immediately.

Special Terms and Conditions.

Customer specific information, including, but not limited to DRS contract capacity, shall remain confidential.

If a new peak demand is set by the customer in the hour following a curtailment event due to the customer resuming the level of activity prior to the curtailment, the customer may request, in writing, that the customer's billing demand be adjusted to disregard that new peak. The Company will promptly evaluate all such requests and approve reasonable requests. In specific circumstances and subject to reasonable conditions, the Company may approve requests in advance.

RIDER D.R.S. 2
(Demand Response Service – Economic)

Availability of Service.

Available on a voluntary basis for demand response service (DRS2) to customers taking firm service from the Company under Tariffs G.S., G.S.-TOD, L.G.S., L.G.S.-TOD, I.P., M.S., W.S.S., or E.H.G. who have the ability to reduce consumption under the provisions under this Rider. DRS2 is also available on a voluntary basis to customers taking interruptible service from the Company under Tariff C.S. IRP2 except to the extent the customer's participation in DRS2 would keep the customer from meeting the load reduction requirements of the contract for C.S. IRP2 service. DRS2 provides participating customers an opportunity to voluntarily respond to locational marginal prices (LMP) by reducing consumption and receiving a payment for such reduction during those times when LMP prices are high.

The customer's demand response service under this Rider will be enrolled in the PJM Interconnection, L.L.C. RTO (PJM) Economic Demand Response Program through the Company. The customer's demand response service is not eligible for enrollment in any PJM demand response program either directly or through a curtailment service provider. Customer's participating in this Rider may elect to use the services of Curtailment Service Providers provided that such arrangements do not violate the terms and conditions of this Rider.

A Curtailment Service Provider is an entity such as a PJM-qualified CSP that the customer has designated to facilitate all or some of the customer notifications and transactions under this Rider.

The customer must provide written notice to the Company of any such designation. Such written notice shall specify the authority that the customer has granted to the Curtailment Service Provider, including any authority to access customer data. The customer is ultimately responsible for compliance with the terms and conditions of this Rider, including any charges under this Rider, in which the customer has voluntarily elected to participate.

The term "customer" as used herein shall mean the customer or an aggregation of customers that have agreed for purposes of participation in this Rider to participate as an aggregation in the same manner as a single customer would under this Rider. The term "participant" as used herein shall mean the customer or customer-designated Curtailment Service Provider as defined above.

Conditions of Service.

(1) The provisions of this Rider qualify under the PJM Economic Demand Response Program as of the effective date. The Company reserves the right to make changes to this Rider in order to continue to qualify under the PJM Economic Demand Response Program, or otherwise, as appropriate.

(2) An interval meter is required. The incremental cost of any special metering, communications or control equipment required for service under this Rider beyond that normally provided shall be borne by the customer.

(3) The Company will inform the participant regarding the communication process and timing required to participate under this Rider. The Customer is ultimately responsible for receiving and acting upon notifications from the Company.

(Cont'd on Sheet No. 37.1)

RIDER D.R.S. 2
(Demand Response Service – Economic)

(Cont'd from Sheet No. 37)

(4) The participant shall not receive credit for any curtailment periods to the extent that the customer's DRS2 curtailable load is already reduced due to a planned or unplanned outage as a result of vacation, renovation, repair, refurbishment, force majeure, strike, economic conditions, or any event other than the customer's normal operating conditions.

(5) **NO RESPONSIBILITY OR LIABILITY OF ANY KIND SHALL ATTACH TO OR BE INCURRED BY THE COMPANY OR THE AEP SYSTEM FOR, OR ON ACCOUNT OF, ANY LOSS, COST, EXPENSE, OR DAMAGE CAUSED BY OR RESULTING FROM, EITHER DIRECTLY OR INDIRECTLY, ANY CURTAILMENT OF SERVICE UNDER THE PROVISIONS OF THIS RIDER.**

Economic Demand Response Options.

Participants shall have two (2) economic demand response options to participate under DRS2. The options include: (1) Day Ahead Market, and (2) PJM Dispatched in Real Time. A description of each DRS2 option is as follows:

1. Day-Ahead Market
   a. The Company submits an energy reduction Offer in the Day Ahead Market based upon information provided in advance by participant. Company submissions to PJM can be made before Noon of the day before participation.
   b. The minimum kW reduction Offer is 100 kW and offers must be in increments of 100 kW.
   c. The Company monitors clearing results, which are made available after 4:00 P.M. of the day before participation. The Company will notify the participant if the Offer was cleared in the Day-Ahead market.
   d. If an Offer clears in the Day Ahead Market, the Company shall provide payment / credit to participant based on the Day-Ahead LMP.
   e. If an Offer clears in the Day Ahead Market, the customer is obligated to curtail consistent with the Offer.
   f. In the event the customer does not reduce sufficient load to meet the cleared Offer commitment, participant shall be billed at 90% of the Real Time LMP times the unreduced load plus Balancing Operating Reserve Charges. Unreduced load shall be the positive difference between the customer's load reduction Offer and the customer's actual load reduced.

2. PJM Dispatched in Real Time
   a. The Company submits operational information regarding the curtailment capability to PJM based upon information provided in advance by participant.
   b. The minimum kW reduction is 100 kW and offers must be in increments of 100 kW.
   c. The Company monitors PJM Real Time operations and notifies the participant if the customer's curtailment capability is dispatched by PJM.
   d. The Company shall provide payment / credit to participant for load reductions that are dispatched by PJM based on actual load reduced, Real-Time LMP and the operational information provided by participant and submitted to PJM.
   e. In the event the customer does not reduce sufficient load to meet the PJM Dispatched commitment, there is no charge to participant under this Rider. Nevertheless, participant shall submit operational information that represents the customer's actual ability to curtail.

(Cont'd on Sheet No. 37.2)

RIDER D.R.S. 2
(Demand Response Service – Economic)

(Cont'd from Sheet No. 37.1)

Curtailed Energy.

For each curtailment period, Curtailed Energy shall be defined as the difference between the customer's Customer Baseline Load (CBL) calculation and the customer's actual energy used during each hour of the curtailment period.

Customer Baseline Load Calculation.

A Customer Baseline Load (CBL) will be calculated for each hour corresponding to each curtailment event hour. Normally, the CBL will be calculated for each hour as the average corresponding hourly demands from the highest four (4) out of the five (5) most recent similar non-event days in the period preceding the relevant curtailment event. The highest load days are defined as the similar days (Weekday, Saturday, Sunday/Holiday as defined by PJM) with the highest energy consumption spanning the curtailment event hours. In cases where the normal calculation does not provide a reasonable representation of normal load conditions, the Company and the participant may develop an alternative CBL calculation that more accurately reflects the customer's normal consumption pattern.

Curtailment Credit.

The Curtailment Credit shall be equal to the product of the Hourly Curtailed Energy and 90% of the applicable LMP (Day-Ahead or Real-Time, based upon Economic Demand Response Option) established by PJM (including congestion and marginal losses). Curtailment Credits will not be provided for energy that is also receiving Curtailment Credits under Rider D.R.S. 1.

Settlement.

The credit, for any curtailments during the billing month, will be paid or credited to the participant within 60 days after the end of the billing month in which the curtailment occurred. Participant shall initiate the settlement process by providing to the Company the sufficient curtailment information to meet the qualifications as set for by PJM. A customer may request the aggregation of individual customer account credits into a single credit.

Customer Charge.

Participants taking service under this Rider shall pay a monthly customer charge of $10.00 per account to offset the cost of the customer-related expenses for additional load determination and billing expenses. If a change in metering equipment or functionality is required, participants taking service under this Rider shall pay the additional cost of installation. The Company will make available to the participant the real time pulse metering data, if requested by the participant, for an additional fee.

(Cont'd on Sheet No. 37.3)

RIDER D.R.S. 2
(Demand Response Service – Economic)

(Cont'd from Sheet No. 37.2)

Term.

Contracts under this Rider shall be made for an initial period of one (1) year and shall remain in effect thereafter until either party provides to the other at least 30 days' written notice of its intention to discontinue service under the terms of this Rider.

Special Terms and Conditions.

Individual customer information, including, but not limited to, operational information and Curtailment Options, shall remain confidential.

RIDER D.R.S. 3
(Demand Response Service – Ancillary)

Availability of Service.

Demand Response Service (DRS3) is available to customers taking firm service from the Company under Tariffs G.S., G.S.-TOD,L.G.S., L.G.S.-TOD, I.P., M.S., W.S.S., or E.H.G. who have the ability to control load under the provisions under this Rider. DRS3 is also available on a voluntary basis to customers taking interruptible service under a contract with the Company, except to the extent the customer's participation in DRS3 would keep the customer from meeting the load reduction requirements of the contract. DRS3 provides participating customers an opportunity to offer demand response to meet the needs of the transmission system and receive a payment or credit for such demand response service.

The customer's demand response service under this Rider will be enrolled in the PJM Interconnection, L.L.C. RTO (PJM) Economic Demand Response Program through the Company, for the purpose of providing Ancillary Services. The customer's demand response service is not eligible for enrollment in any PJM demand response program either directly or through a curtailment service provider, except as noted within this rider. Customers participating in this Rider may elect to use the services of Curtailment Service Providers provided that such arrangements do not violate the terms and conditions of this Rider.

A Curtailment Service Provider is an entity such as a PJM-qualified CSP that the customer has designated to facilitate all or some of the customer notifications and transactions under this Rider.

The customer must provide written notice to the Company of any such designation. Such written notice shall specify the authority that the customer has granted to the Curtailment Service Provider, including any authority to access customer data. The customer is ultimately responsible for compliance with the terms and conditions of this Rider, including any charges under this Rider, in which the customer has voluntarily elected to participate.

The term "customer" or "resource" as used herein shall mean the customer or an aggregation of customers that have agreed for purposes of participation in this Rider to participate as an aggregation in the same manner as a single customer would under this Rider. The term "participant" as used herein shall mean the customer or customer-designated Curtailment Service Provider as defined above.

Conditions of Service.

(1) The provisions of this Rider qualify under the PJM Economic Demand Response Program as of the effective date, and as such, the customer must be registered in the PJM Economic Demand Response program. The Company reserves the right to make changes to this Rider in order to continue to qualify under the PJM Economic Demand Response Program, PJM manual changes and/or any changes to regulatory standards that apply.
(2) Ancillary product specific metering and/or telemetering is required. Meter and telemetry equipment shall meet the minimum PJM and Company requirements for each Ancillary Service desired to be supplied by the customer. The incremental cost of any special metering, communications, control equipment and all equipment required to integrate into the Company's systems required for service under this Rider beyond that normally provided shall be borne by the customer.

(Cont'd on Sheet No. 38.1)

RIDER D.R.S. 3
(Demand Response Service – Ancillary)

(Cont'd from Sheet No. 38)

(3) The Company will inform the participant regarding the communication process and timing required to participate under this Rider. The customer is ultimately responsible for receiving and acting upon notifications from the Company or, if the customer is participating through a CSP, from the customer's CSP.

(4) The participant shall not receive credit for any curtailment periods to the extent that the customer's DRS3 curtailable load is already reduced due to a planned or unplanned outage as a result of vacation, renovation, repair, refurbishment, force majeure, strike, economic conditions, or any event other than the customer's normal operating conditions.

(5) **NO RESPONSIBILITY OR LIABILITY OF ANY KIND SHALL ATTACH TO OR BE INCURRED BY THE COMPANY OR THE AEP SYSTEM FOR, OR ON ACCOUNT OF, ANY LOSS, COST, EXPENSE, OR DAMAGE CAUSED BY OR RESULTING FROM, EITHER DIRECTLY OR INDIRECTLY, ANY SERVICE PROVIDED UNDER THE PROVISIONS OF THIS RIDER.**

(6) The customer will agree to indemnify and hold the Company harmless from and against all claims, liability, damages, and expenses arising from the customer's or customer's CSP's failure to satisfy any of the customer's obligations arising under PJM's Tariff, the PJM Reliability Assurance Agreement the PJM Operating Agreement (including Manual 11), or Rider D.R.S. 3, including, with regard to any referral to the PJM Market Monitor or Federal Energy Regulatory Commission's Office of Enforcement concerning the customer's participation or non-performance in the ancillary services market within which the Customer participates through Rider D.R.S. 3. The customer further will agree to assist the Company in responding to an inquiry from PJM, the PJM Market Monitor, or the Federal Energy Regulatory Commission's Office of Enforcement concerning the customer's participation or non-performance in the ancillary services market within which the customer participates through Rider D.R.S. 3.

Ancillary Demand Response Options.

Participants shall have three (3) Ancillary service options to participate under DRS3. The options include: (1) Day-Ahead Scheduling Reserves, (2) Synchronized Reserves Market and (3) Regulation Market. The detail for each DRS3 option is as follows:

1. DAY-AHEAD SCHEDULING RESERVES (DASR)

The Company is not providing Day-Ahead Scheduling Reserves service at the present time. The following terms and conditions shall apply should the Company begin providing Day-Ahead Scheduling Reserves service in the future.

Description: Day-Ahead Scheduling Reserves is the procurement of supplemental, 30-minute reserves on the PJM system on a day-ahead basis. It is an offer-based market for 30-minute reserve that can be provided by both generation and demand resources. It will clear existing reserve requirements on a day-ahead, forward basis.

(Cont'd on Sheet No. 38.2)

RIDER D.R.S. 3
(Demand Response Service – Ancillary)

(Cont'd from Sheet No. 38.1)

Day-Ahead Scheduling Reserves Requirements / Implementation

a. One-minute interval metering is required for customers electing to participate under the Day-Ahead Scheduling Reserves option.
b. Participants electing the Day-Ahead Scheduling Reserves option agree to provide 30-minute reserves on a day-ahead basis. Participants shall have 30-minutes to reduce load to the assigned MW amount.
c. The Company submits bids to supply PJM Day-Ahead Scheduling Reserves, in the PJM Day-Ahead Market, based upon information provided in advance by participant. Customer shall be required to submit data information at a time suitable for the Company to manage or facilitate day-ahead market activities.
d. Load response is dispatched by PJM in real-time.
e. Customer communication method must be approved by PJM.
f. A Demand Resource with a Day-ahead Scheduling Reserve award is obligated to reduce load within 30 minutes of notification for all hours of the operating day in which it received the DASR award.
g. For Demand Resources, measurement is the difference between the demand resource's MW consumption at the time a resource is requested by PJM dispatch to reduce and its MW consumption after 30 minutes of the request. In order to allow for small fluctuations and possible telemetry delays, demand resources consumption at the start of the event is defined as the greatest telemetered consumption between one (1) minute prior to and one (1) minute following the issuance of the dispatch instruction. Similarly, a demand resource's consumption thirty minutes after the dispatcher request is defined as the lowest consumption measured between twenty nine (29) and thirty (31) minutes after the start of the request.

Day-Ahead Scheduling Reserves Payment / Credit:
The Company shall provide payment / credit to participant as the product of the Day-Ahead Cleared Scheduling Reserve (MW) or assigned MW and the Day-Ahead Scheduling Reserve (DASR) Clearing Price as determined by PJM. In the event PJM dispatches a reduction in load, participant will receive payment / credit as a product of the amount of reduction and AEP Zonal LMP ("LMP) for the duration of the dispatch period.
Payment / credit will not be provided for energy that is also receiving payment or curtailment credits under Rider D.R.S. 1 or Rider D.R.S. 2.

Day-Ahead Scheduling Reserves Non-Compliance Penalty:

In the event the customer does not reduce assigned load in compliance with the Day-Ahead Scheduling Reserves program rules, then a penalty shall be issued to the customer, which shall include the following:

1. Forfeiture of revenue over hours assigned for the day, and any contiguously awarded hours prior to such compliance failure.

(Cont'd on Sheet No. 38.3)

RIDER D.R.S. 3
(Demand Response Service – Ancillary)

(Cont'd from Sheet No. 38.2)

SYNCHRONIZED RESERVES (SR) MARKET

Description: SR Market provides for the supply of electricity if the grid has an unexpected need for more power on short notice. Demand resources may bid to supply synchronized reserve by reducing their energy use within ten (10) minutes. Synchronized Reserve resources include demand response and generator resources.

Synchronized Reserves Market Requirements / Implementation:

a. One-minute interval metering is required for customers electing to participate under the SR Market option.
b. The minimum kW reduction is 100 kW.
c. Customer shall be required to reduce load within ten (10) minutes when notified by the Company for a SR event, if cleared in SR market.
d. Participation in Synchronized Reserves Market requires 24-hour all-call availability unless participant defines hour(s) of participation.
e. The Company submits operational information regarding the curtailment capability to PJM based upon information provided in advance by participant who shall be required to submit information at a time suitable for the Company to manage or facilitate Synchronized Reserves market activities. At the customer's election, the customer's CSP may perform this function instead of the Company.
f. The Company monitors PJM Synchronized Reserves Market operations and notifies the participant if the customer's specified load is cleared by PJM. At the customer's election, the customer's CSP may perform this function instead of the Company.

Customers shall participate in the Synchronized Reserves Market through the "Tier 2" option. The Company is not providing "Tier 1" Synchronized Reserves Market service at the present time. The following "Tier 1" option terms and conditions shall apply should the Company begin providing "Tier 1" Synchronized Reserves Market service in the future.

i. **"Tier 1" option** is voluntary during a PJM SR event. In the event the customer's load does not clear, customer can still reduce specified load. Customer is eligible for payment if they are capable of receiving real-time instruction from Company, 24-hours a day, and reduce load within 10 minutes.

(Cont'd on Sheet No. 38.4)

RIDER D.R.S. 3
(Demand Response Service – Ancillary)

(Cont'd from Sheet No. 38.3)

Tier 1 Payment / Credit:
Payment / credit under Tier 1 is equal to the integrated decrease in MW consumption for demand response resources from each resource over the length of a synchronized reserve event times the Synchronized Energy Premium. If load reduction is not achieved by the time the event is cancelled, no payment/credit will be granted.

Synchronized Energy Premium is defined as the average of the 5-minute LMPs calculated during the synchronized reserve event plus $50 per MWh less the hourly integrated LMP.

Other than any applicable synchronized energy premium, payment / credits will not be provided for energy that is also receiving payment or curtailment credits under Rider D.R.S. 1 or Rider D.R.S. 2.

Tier 1 Non-Compliance Penalty:
No penalty for customers not complying under Tier 1.

ii. **"Tier 2" option** is the event the offer clears in the hourly market, then a mandatory reduction of load in ten (10) minutes is required by the customer during a PJM SR event. Tier 2 consists of the additional resources that are synchronized to the grid and operating at a point that deviates from economic dispatch to provide additional synchronized reserve not available from Tier 1 resources.

Tier 2 Payment / Credit:
Payment / credit is provided to resource owner that has pool-scheduled synchronized reserve.

SR payment / credit for resources assigned pool-scheduled synchronized reserve is the resource's synchronized reserve offer times its assigned synchronized reserve capability less any shortfall due to failure to provide assigned capability during a synchronized reserve event (plus opportunity cost, energy use costs, and startup costs incurred, for generators), as applicable.

Tier 2 Non-Compliance Penalty:
In the event the customer does not reduce specified load to meet the PJM Synchronized Reserves Market under a Tier 2 commitment, then a penalty shall be issued to the customer consistent with PJM Manual 11, Section 4.2.12, as it may be amended from time to time, which shall include the following:

(Cont'd on Sheet No. 38.5)

RIDER D.R.S. 3
(Demand Response Service – Ancillary)

(Cont'd from Sheet No. 38.4)

Tier 2 Non-Compliance Penalty:
In the event the customer does not reduce specified load to meet the PJM Synchronized Reserves Market under a Tier 2 commitment, then a penalty shall be issued to the customer consistent with PJM Manual 11, Section 4.2.12, as it may be amended from time to time, which shall include the following:

1. The Customer's Tier 2 resource shall be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for all Real-time settlement intervals (5 minutes) the resource was assigned or self-scheduled Tier 2 Synchronized Reserve on the day the event occurred, and;

2. The Customer shall incur a retroactive obligation to refund at the Synchronized Reserve Market Clearing Price the amount of the shortfall measured in MW for all of the Real-time settlement intervals the Tier 2 resource was assigned or self-scheduled over the immediate past interval, the duration of which is equal to the lesser of the average number of days between events as determined by the annual review of the last 2 years, or the number of days since the resource failed to respond with its assigned or self-scheduled Synchronized Reserve amount in response to a Synchronized Reserve Event.

These provisions apply to all customers taking service under the Synchronized Reserves Market Tier 2 Participation option in Rider D.R.S. 3, including both those customers participating directly and those that do so through a CSP. Determination and verification of reductions shall be consistent with the requirements of the PJM Synchronized Reserves Market and PJM Manual 11, including provisions related to "batch load" resources. The customer will be responsible for paying all charges associated with any failure to reduce specified load to meet a PJM synchronized reserve event.

2. PERFORMANCE BASED REGULATION MARKET

The Company is not providing Performance Based Regulation service at the present time. Customers who desire to participate in the Regulation Market utilizing Demand Response shall make the necessary arrangements with a qualified PJM Regulation Service Provider for enrollment, implementation, terms and conditions and settlement purposes. Such customer participation shall also require a contract to be entered into between the Company and customer. The terms and conditions described below under the Performance Based Regulation Market (applicable should the Company begin providing Performance Based Regulation Service), shall not be applicable to such contract. The Customer Charge, under this Rider, shall not apply to customers providing Performance Based Regulation via a Regulation Service Provider.

(Cont'd on Sheet No. 38.6)

RIDER D.R.S. 3
(Demand Response Service – Ancillary)

(Cont'd from Sheet No. 38.5)

Description: Performance Based Regulation Market is a market-based system for the purchase and sales of the Regulation ancillary service. Performance Based Regulation Market service corrects for short-term changes in electricity use that might affect the stability of the power system. This service helps match generation and load, and adjusts generation output to maintain desired frequency. It is an automatic adjustment of load in response to a PJM dynamic regulation control signal. Participating customers are generally compensated based on both the market clearing prices and on how accurately and quickly they respond to PJM Regulation signals.

Performance Based Regulation Market Requirements / Implementation

a. Real-time telemetry (telemetering) required for customers electing to participate under the Regulation Market option.
b. The minimum kW offer shall be 100 kW.
c. Customer shall be required to submit data information at a time suitable for the Company to manage or facilitate day-ahead and intraday market activities.
d. Resource owners wishing to sell regulation service must at least supply a cost-based regulation offer. All resources listed as available for regulation with no offer price have their offer prices set to zero.
e. In the event load is cleared by PJM in the Performance Based Regulation Market, a mandatory response or automatic adjustment of load in response to PJM regulation control signal is required.
f. Customers electing this Performance Based Regulation Market option shall decrease load or increase load as directed by the Company within five (5) minutes of notification.
g. PJM clears the regulation market simultaneously with the synchronized reserve market, and posts the results no later than 30 minutes prior to the start of the operating hour.
h. Each participant is required to pre-certify regulation capability prior to participation under this rider and avail itself to periodic testing of capability.
i. Each participant shall be required to pay the Company's actual costs to set up and test its systems to enable Regulation participation. The Company shall provide the Participant with an itemized invoice.

Performance Based Regulation Market Payment / Credit:
The Company shall provide payment / credit in accordance with PJM Manual 28.

Regulation Market Non-Compliance Penalty:
In the event the customer fails to adequately follow the PJM Regulation signal, customer may be subject to disqualification and subsequent recertification.

Regulation Market Qualifications / Eligibility:
The following resources criteria must be met to participate in the Regulation Market:
- Resources must be able to receive an AGC signal.
- Resources must demonstrate minimum performance standards, as set forth in the PJM Manual 12: Balancing Operations, Section 4: Providing Ancillary Services.
- New resources must pass an initial performance test (minimum 75% compliance required).
- Resources must exhibit satisfactory performance on dynamic evaluations.

(Cont'd on Sheet No. 38.7)

RIDER D.R.S. 3
(Demand Response Service – Ancillary)

(Cont'd from Sheet No. 38.6)

- Resources MW output must be telemetered to the PJM control center in a manner determined to be acceptable by PJM.
- Demand Resources must be able to provide the smallest quantity of MW of Regulation Capability required by PJM, currently 0.1 MW, in order to participate in the Regulation Market.
- Demand Resources must complete initial and continuing training on Regulation and Synchronized Reserve Market as documented in Manual 40: Certification and Training Requirements, Section 2.6: Training Requirements for Demand Response Resources Supplying Regulation and Synchronized Reserve.

General Terms and Conditions under Rider DRS-3

Curtailment Credit.

Customers enrolled in Riders D.R.S.-1, D.R.S.-2 and D.R.S.-3 shall only receive a single curtailment credit for energy reduced under one of these three riders. For example, curtailment credits for any energy reduced under the DASR option of Rider D.R.S.-3 are provided under Rider D.R.S.-2.

Settlement.

The Company will charge, pay or credit to a participant any amount owed or credit due to the customer for a billing month, for any curtailments during the billing month or otherwise, within 60 days after the end of the billing month. A customer may request the aggregation of individual customer account credits into a single credit.

Customer Charge.

Participants taking service under this Rider shall pay a monthly customer charge of $150.00 per account to offset the cost of the customer-related expenses for additional load determination and billing expenses. If a change in metering equipment or functionality is required, participants taking service under this Rider shall pay the additional cost of equipment and installation. The Company will make available to the participant the real time pulse metering data, if requested by the participant, for an additional fee.

Term.

Contracts under this Rider shall be made for an initial period of one (1) year and shall remain in effect thereafter until either party provides to the other at least 30 days' written notice of its intention to discontinue service under the terms of this Rider. A new initial period will not be required for a customer that has previously participated.

Special Terms and Conditions.

Individual customer information, including, but not limited to, operational information and Curtailment Options, shall remain confidential.

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 39**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

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.

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 that are new to the State of Indiana. 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, I.P. or C.S.-IRP-2 who meet the following requirements:

(1) A new customer must have a billing demand of 500 kW~~kVA~~ or more. An existing customer must increase billing demand by 500 kW~~kVA~~ 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) A new customer, or the expansion by an existing customer, must result in the creation of at least ten (10) full-time equivalent jobs (FTE) maintained over the contract term or exceed one million dollars ($1,000,000) of capital investment at the service location. The Company reserves the right to verify FTE job counts and / or capital investment requirements. Each EDR customer shall comply with reasonable requests for information from the Company for purposes of determining such compliance. Failure to maintain the minimum required FTE jobs or satisfy the capital investment requirement will result in the termination of the contract or agreement addendum for service under this Rider.

(4) 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.

(5) Revenues expected to be derived from the EDR customer must be expected to exceed the incremental costs of serving that customer over the term of the contract.

Availability is limited to customers on first-come, first-served basis for loads aggregating 250 MW

~~VAW~~. 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.

(Cont'd on Sheet No. 39.1)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

ECONOMIC DEVELOPMENT RIDER

(Cont'd from Sheet No. 39)

(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 BillingDemand.

(4) 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 is 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 No. 14~~15~~ of the Company's Terms and Conditions ofService.

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.

The monthly billing credit under this Rider shall be the product of the qualifying incremental billing demand and the applicable Credit Factor. The monthly billing credit shall be zero if the minimum 500 kW~~kVA~~ increase over the Base Maximum Billing Demand is not attained that month.

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.

(Cont'd on Sheet No. 39.2)

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 39.2**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ECONOMIC DEVELOPMENT RIDER

(Cont'd from Sheet No. 39.1)

Credit Options		**Billing Months in Contract Terms**		**Billing Credit per kW ~~kVA~~**
1 - Inclining		1st through 12th		$7.15
		13th through 24th		$9.35
		25th through 36th		$11.00
		37th through 48th		$12.65
		49th through 60th		$14.85
2 - Levelized		1st through 12th		$11.00
		13th through 24th		$11.00
		25th through 36th		$11.00
		37th through 48th		$11.00
		49th through 60th		$11.00
3 - Declining		1st through 12th		$14.85
		13th through 24th		$12.65
		25th through 36th		$11.00
		37th through 48th		$9.35
		49th through 60th		$7.15

The appropriate Billing Credit 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.

(Cont'd on Sheet No. 39.3)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
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I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 39.3

ECONOMIC DEVELOPMENT RIDER

(Cont'd from Sheet No. 39.2)

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.

Company Reporting Requirements

On or before March 31 of each year, the Company shall file a report with the IURC that contains the following;

(1) Customer name, full business address and tariff rate class.
- a. Additional demand kW and monthly additional load in kWh.
- b. Economic Development Rider contract signature date.
- c. Start and end dates of the Economic Development Rider contract.

(2) All customers under the EDR meet the threshold requirements for eligibility.
- a. Project description.
- b. Number of additional jobs created or amount of the investment.
- c. Economic Development incentives received.

(3) All variances found during the verification of (2) above.

(4) Demonstrate that the revenues from customers under the EDR exceed the incremental costs incurred to serve each customer over the term of the EDR contract.

(5) Identify projects whose location on a brownfield site was considered by state or local economic development entities.

(6) The Company must retain the analysis for each EDR contract offering until the first of the end of the EDR tariff approval period or the Company's next base rate case.

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STEVEN F. BAKER
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EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

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I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 40

IM GREEN RIDER

Availability of Service.

The Local Renewable Program option is available on a voluntary basis to metered customers who are in good standing and desire to purchase renewable energy from I&M's solar, wind and hydro generation resources through the purchase of renewable energy certificates (RECs) sourced from I&M's renewable resources.

The National Renewable Program option is available on a voluntary basis to metered customers who are in good standing and desire to purchase RECs sourced from renewable resources located within the United States of America.

The Custom Agreement option is available to customers taking metered service under the Company's I.P. and C.S.-IRP2 tariffs, or multiple G.S. and / or L.G.S. tariff accounts with common ownership under a single parent company that can aggregate multiple accounts to exceed 1,000 kW monthly peak demand over a 12-month average.

Conditions of Service.

Customers who wish to attribute a specific portion of their service to renewable energy may purchase RECs under the Local and National Program options each month as a percentage of their monthly kWh usage in 10% increments. Customers who purchase RECs through this tariff have the right to claim the renewable energy generation and associated emission footprint reduction.

The Company will retire the RECs associated with I&M's renewable resources for the energy purchased by participating customer under the Local Renewable Program option. The Company will purchase and retire RECs associated with nationally available renewable resources for the RECs purchased by participating customers under the National Renewable Program option. RECs will be retired on an annual basis upon receipt of payment from the customer. The proceeds of this rider, net of administrative fees, will be used to offset the cost of the Fuel Cost Adjustment Rider for all customers.

Monthly Rate.

In addition to the monthly charges determined according to the Company's rate schedule under which the customer takes service, the customer shall also pay the following rate for the REC purchase. The customer can elect a percentage of monthly usage, in 10% increments, to be dedicated to the IM Green rider. The charge will be applied to the customer's bill as a separate line item.

Local Program option (for RECs from I&M Wind, Solar or Hydro Projects)

Charge: $0.01479 ~~106~~ for each kWh consumed

(Cont'd on Sheet No. 40.1)

ISSUED BY
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FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

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IN CAUSE NO. 45576

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 40.1

IM GREEN RIDER

(Cont'd from Sheet No. 40)

The Company will provide RECs from I&M Wind, Solar or Hydro projects to fulfill customer subscriptions under this option. Participation under this program will be limited to the availability of RECs associated with I&M's wind and solar generation resources. The local option will be priced semi-annually, based on the average REC prices over six-month period as published in S&P Global Renewable Energy Credit Index for the New Jersey Class I REC. If the REC product index is no longer available or the state of Indiana adopts a Renewable Portfolio Standard that includes solar, wind, hydro and other renewables the Company will select a replacement REC product as the basis for establishing the corresponding rate.

National Program option (for RECs from national resources)

Charge: $0.00324 ~~2~~ for each kWh consumed

The Company will purchase RECs in the over the counter market representing nationally available wind, hydro or solar and other renewable RECs to meet the customers need under this tariff. The Company will annually evaluate the market prices for RECs and will file a 30 day filing to modify the charge on this tariff if necessary to fulfill the REC obligations under this tariff.

Custom Agreement option

Charges for service under this option will be set forth in the written agreement between the Company and the Customer and will reflect a combination of the tariff service rates otherwise available to the Customer and the cost of the renewable energy being contracted for by the Customer.

Term.

This is a voluntary program.

Customers eligible for this Rider may participate by applying to the Company for service under this Rider. Once approved for service under this Rider, service will begin within a minimum of fifteen (15) days of the customer's regular scheduled meter reading date. Customers under the Standard Program Option may terminate service under this Rider by notifying the Company with at least thirty (30) day notice prior to the customer's regular scheduled meter reading date.

Custom Agreement option term must be a minimum of one year and will be determined in the written agreement between the Company and the Customer.

(Cont'd on Sheet No. 40.2)

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 40.2

IM GREEN RIDER
(Cont'd from Sheet 40.1)

Special Terms and Conditions.

Under the Custom Agreement option, customer specific information, including, but not limited to contract rates, purchased amounts of renewable energy and generation resources, shall remain confidential.

This Rider is subject to the Company's Terms and Conditions of Service and all provisions of the standard rate schedule under which the customer takes service, including all payment provisions.

RIDER NMS
(Net Metering Service Rider)

Availability of Service.

This rider is available to customers in good standing who own and operate an eligible net metering renewable energy resource such as solar photovoltaic, wind, biomass, or hydro electrical generating facility designed to operate in parallel with the Company's system. Customers served under this rider must also take service from the Company under the otherwise applicable standard service tariff.

The total rated generating capacity of all net metering customers served under this rider shall be limited to one and one half percent (1.5%) of the Company's most recent Indiana aggregate summer peak load. At least forty percent (40%) of the capacity is reserved solely for participation by residential customers and fifteen percent (15%) of the capacity is reserved for organic waste biomass resources as defined in IC 8-1-37-4(a)(5). 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, an eligible net metering facility is an electrical generating facility that complies with all of the following requirements:

   (a) is fueled by a renewable energy resource as defined in IC 8-1-37-4(a)(1) through IC 8-1-37-4(a)(1)(8) such as solar photovoltaic, wind, biomass, or hydroelectric energy;

   (b) has a nameplate capacity less than or equal to 1 MW;

   (c) is owned and operated by the customer and is located on the customer's premises;

   (d) is intended primarily to offset all or part of the customer's own electrical load requirements; and

   (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.

2. 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 Application for Interconnection with the Indiana Michigan Power Company Distribution System and a one-line diagram showing the configuration of the proposed net metering facility. The Company will provide copies of all applicable forms upon request.

3. An Addendum to Contract for Electric Service between the Company and the net metering customer must be executed before the net metering facility may be interconnected with the Company's system.

(Cont'd on Sheet No. 41.1)

RIDER NMS
(Net Metering Service Rider)

(Cont'd from Sheet No. 41)

4. Customer-owned generator equipment and installations must comply with the Company's Technical Requirements described in this tariff.

5. The net metering customer shall provide the Company proof of qualified installation of the net metering facility. Certification by a licensed electrician shall constitute acceptable proof.

6. The net metering customer shall install, operate, and maintain the net metering facility in accordance with the manufacturer's suggested practices for safe, efficient, and reliable operation in parallel with the Company's system.

7. The Company may, at its own discretion, isolate any net metering facility if the Company has reason to believe that continued interconnection with the net metering facility creates or contributes to a system emergency. System emergencies causing discontinuance of interconnection shall be subject to verification at the Commission's discretion.

8. The Company may perform reasonable on-site inspections to verify the proper installation and continuing safe operation of the net metering facility and the interconnection facilities, at reasonable times and upon reasonable advance notice to the net metering customer.

9. A net metering customer operating a net metering facility shall maintain homeowners, commercial, or other insurance providing coverage in the amount of at least one hundred thousand dollars ($100,000) for the liability of the insured against losses or damages arising from the use of the customer's net metering facility. The customer must submit evidence of such insurance to the Company with the Interconnection Application. The Company's receipt of evidence of liability insurance does not imply an endorsement of the terms and conditions of the coverage.

10. The Company and the net metering customer shall indemnify and hold the other party harmless from and against all claims, liability, damages, and expenses, including attorney's fees, based on any injury to any person, including loss of life, or damage to any property, including loss of use thereof, arising out of, resulting from, or connected with, or that may be alleged to have arisen out of, resulted from, or connected with an act or omission by such other party, its employees, agents, representatives, successors, or assigns in the construction, ownership, or maintenance of such party's facilities used in net metering. This indemnification provision is not applicable in the case of government net metering customers that are restricted from entering into indemnification provisions.

(Cont'd on Sheet No. 41.2)

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 41.2

RIDER NMS
(Net Metering Service Rider)

(Cont'd from Sheet No. 41.1)

Metering.

One of the following metering options, if not already present, shall be installed on the net metering customer's premises by the Company to properly record the net kWh of a net metering facility:

(1) One main watt-hour meter capable of measuring the net flow of energy.

(2) One main watt-hour meter measuring the flow of energy to the net metering customer and a second watt-hour meter measuring the flow of energy to the Company. The reading of the second meter will be subtracted from the reading of the main meter to obtain a measurement of net kWh for billing purposes.

The Company may install one or more additional meters to monitor the flow of electricity.

Monthly Charges and Billing.

Monthly charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the Company's standard service tariff under which the customer would otherwise be served, absent the customer's eligible net metering facility. Energy charges under the customer's standard tariff shall be applied to the customer's net energy for the billing period to the extent that the net energy exceeds zero. If the customer's net energy is zero or negative during the billing period, the customer shall pay only the non-energy usage portions of the standard tariff bill. If the customer's net energy is negative during a billing period, the net metering customer shall be credited in the next billing period for the kWh difference. When the net metering customer elects to no longer take service under this Net Metering Service Rider, any unused credit shall revert to the Company.

Contract.

A written agreement may, at the Company's option, be required to fulfill the provisions of Items 2, 14~~5~~, and/or 17~~8~~ of the Company's Terms and Conditions of Service.

(Cont'd on Sheet No. 41.3)

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 41.3**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

RIDER NMS
(Net Metering Service Rider)

(Cont'd from Sheet No. 41.2)

Special Terms and Conditions.

This rider is subject to the Company's Terms and Conditions of Service and all provisions of the standard service tariff under which the customer takes service. This rider is also subject to provisions of the Company's Net Metering Tariff Technical Requirements.

Technical Requirements.

These technical requirements relate to the interconnection of a net metering facility to the Company's distribution system. Interconnection enables the net metering facility to operate in parallel with the Company's distribution system. Inverter based systems listed by Underwriters Laboratories (UL) to UL standard 1741 published May 7, 1999, as revised January 28, 2010 (UL 1741) will be accepted as meeting the technical interconnection requirements tested by UL 1741. Non-inverter based systems and interconnection requirements not tested by UL 1741 shall comply with standard, IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems." IEEE publications are available from the Institute of Electrical and Electronics Engineers, 443 Hoes Lane, P. O. Box 1331, Piscataway, NJ 08855-1331 (http://standards.ieee.org/). Since UL 1741 and IEEE 1547 do not address planning, designing, operating, or maintaining the utility's distribution system nor all of the potential system impacts the proposed net metering facility may create beyond the point of common coupling, certain additional technical requirements are contained herein.

These technical requirements are supplementary to and do not intentionally conflict with or supersede applicable laws, ordinances, rules, or regulations established by Federal (including all applicable safety and performance standards of the National Electrical Code), State, and other governmental bodies. The customer proposing to install a net metering facility is responsible for conforming to all applicable laws, ordinances, rules, or regulations established by Federal, State, and other governmental bodies.

The Company will provide the screening of all interconnection applications and, if necessary, an interconnection study to determine the impact of the net metering facility on the Company's distribution system beyond the point of common coupling.

To assure that the safety, reliability, and power quality of the distribution system is not degraded by the interconnection of the net metering facility:

(1) The net metering facility shall comply with these technical requirements.

(2) Any new distribution system facilities, distribution system modifications, and/or modifications to the net metering facility identified by the interconnection study shall be completed prior to interconnection.

(3) The net metering facility shall be operated and maintained as agreed upon by the parties.

(Cont'd on Sheet No. 41.4)

RIDER NMS
(Net Metering Service Rider)

(Cont'd from Sheet No. 41.3)

Data for all major equipment proposed by the customer to satisfy the technical requirements must be submitted for review by the Company with the completed Interconnection Application. The use of pre-certified equipment will facilitate the Company's review. Pre-certified equipment has been tested and certified by recognized national testing laboratories (i.e., UL 1741) as suitable for interconnection with a distribution system based upon compliance with IEEE Standard 1547. Suitability for interconnection does not imply that pre-certified equipment may be interconnected without a study to determine system impact. The Company will endeavor to timely communicate the results of its review and study to the customer.

The interconnection system hardware and software design requirements in the technical requirements are intended to assure protection of the Company's distribution system. Any additional hardware and software necessary to protect equipment at the net metering facility is solely the responsibility of the customer to determine, design, and apply.

If an interconnection transformer is required, the transformer must comply with the applicable current ANSI Standard from the C57.12 series of standards that specifies the requirements for transformers. ANSI publications are available from the Sales Department, American National Standards Institute, 25 West 43rd Street, 4th Floor, New York, NY 10036 (http://www.ansi.org/). An interconnection transformer would typically be required when the voltage at the point of common coupling is greater than 480 volts and the customer's electrical system design dictates. If required, the cost and ownership of the interconnection transformer shall reside with the customer.

The transformer should have voltage taps on the high and/or low voltage windings sufficient to assure satisfactory generator operation over the range of voltage variation expected on the Company's distribution system. The customer needs to assure sufficient voltage regulation at its facility to maintain an acceptable voltage level for its equipment during such periods when its net metering facility is off line.

If a main circuit breaker (or circuit switcher) between the interconnection transformer and the Distribution System is required, the device must comply with the applicable current ANSI Standard from the C37 series of standards that specifies the requirements for circuit breakers, reclosers, and interrupting switches. An interconnection circuit breaker would typically be required when the voltage at the point of common coupling is greater than 480 volts and the customer's electrical system design dictates. If required, the cost and ownership of the interconnection circuit breaker shall reside with the customer.

Any circuit breaker (or circuit switcher) must have adequate interrupting capability for the maximum expected short circuit duty. The Company will provide information identifying the contribution from the electric system to faults at the proposed site.

(Cont'd on Sheet No. 41.5)

RIDER NMS
(Net Metering Service Rider)

(Cont'd from Sheet No. 41.4)

A disconnecting device must be located at the point of common coupling for all interconnections. For three-phase interconnections, the disconnecting device must be gang operated. The disconnecting device must be accessible to Company personnel at all times and be suitable for use by the Company as a protective tagging location. The disconnecting device shall have a visible open gap when in the open position and be capable of being locked in the open position. The cost and ownership of the main disconnect switch shall reside with the customer.

The device must comply with the applicable current ANSI Standard from the C37 series of standards that specifies the requirements for circuit breakers, reclosers, and interrupting switches.

The closest available system voltage as well as equipment and operational constraints influence the chosen point of interconnection. The Company will consult with the customer to determine the acceptability of a particular interconnection point.

For situations where the customer's net metering facility will only be operated in parallel with the Company's distribution system for a short duration (less than 100 milliseconds), as in a make-before-break automatic transfer scheme, the requirements of IEEE 1547 do not apply except as noted in Clause 4.1.4.

The customer is responsible for operating the proposed net metering facility such that the voltage unbalance attributable to the net metering facility shall not exceed 2.5% at the point of common coupling. Voltage unbalance is the maximum phase deviation from average as specified in ANSI C84.1.

The Company reserves the right to witness compliance testing at the time of installation and maintenance testing of the interconnection system for compliance with these technical requirements.

The customer is responsible for establishing a program for and performing periodic scheduled maintenance on the net metering facility's interconnection system (relays, interrupting devices, control schemes, and batteries that involve the protection of the Company's distribution system). A periodic maintenance program is to be established in accordance with the requirements of IEEE 1547. The Company may examine copies of the periodic test reports or inspection logs associated with the periodic maintenance program. Upon the Company's request, the Company shall be informed of the next scheduled maintenance and be able to witness the maintenance performed and any associated testing.

The Company reserves the right, at the Company's expense, to install special test equipment as may be required to perform a disturbance analysis and monitor the operation and control of the net metering facility to evaluate the quality of power produced by the net metering facility.

RIDER H.E.M.
(Home Energy Management Rider)

Bring Your Own Device (BYOD) Thermostat Demand-side Management Program

Availability of Service.

Available on a voluntary basis for customers receiving residential electric service who desire to participate in a state-of-the art demand-side management program.

For non-owner occupied multi-family dwellings, the Company may require property owner authorization for customers to install the required smart, WiFi enabled load control equipment and, if necessary, auxiliary communicating devices such as remote sensors or additional control devices. Customers will not be eligible for this rider if the property owner does not allow installation of such equipment.

Program Description.

To participate, customers must install program compliant smart, WiFi enabled load control equipment, connect that equipment to their home WiFi broadband internet connection, and maintain that connection with continuous operation and availability for the duration of the program annual operational period defined as May through September of each program year. All such devices shall be installed at a time that is consistent with the orderly and efficient deployment of this program. Customer load control equipment must comply with the Company's approved list of devices. Initially, the Company will determine and provide a program smart, or WiFi connected thermostat compliant list, but as technology, device capability, and the program's load management platform evolves, the Company may allow and provide for additional approved devices, where the program is eventually anticipated to accommodate a Bring Your Own Device (BYOD) load management capability. The Company may provide for and determine the appropriate level of customer equipment rebates, as needed and required, in order to facilitate customer installation and ownership of the required equipment as part of the Home Energy Management Program

The Company will utilize a load management software platform that will operate and control Customer load control devices primarily to reduce customer's demand and use. The Company's load management platform will primarily operate to optimize and/or reduce demand use through either peak period use load reduction management techniques or load shaping to achieve optimum and efficient Customer demand use of electricity.

Program demand reduction/load management activities can occur during coincident peak and non-coincident peak demand periods according to Company and PJM system load forecasting techniques. Coincident peak, non-coincident peak, and emergency demand reduction/load management activities will be coordinated during electric power system peak load periods determined according to both I&M system and PJM system requirements. The Company plans to utilize load management activities focused primarily on managing home temperature set points with consideration to minimize customer comfort impact during the period of peak demand load management activity. Peak and emergency conditions demand reduction activities will primarily focus on control of the central electric cooling/heat pump unit(s) during summer month peak demand periods. Peak period demand load control events can occur based on I&M and/or PJM system need, as determined by the Company

(Cont'd on Sheet No. 42.1)

RIDER H.E.M.
(Home Energy Management Rider)
(Cont'd from Sheet No. 42)

Peak period load management events shall curtail customer load based on system need, at the sole discretion of the Company, during the months of May through September and shall not exceed 15 events per year with no single event lasting more than six (6) consecutive hours and no more than one event per day.

The Company may communicate events to customers through the load management platform, via a smart phone application push notification, or via email or other electronic notification means. The customer may opt out of a Company planned load management event by providing the Company appropriate notice through the requisite and identified program opt out means of communication. The Company's load management software algorithm will facilitate and accept the temperature adjustment as an event opt-out unless customer internet and WiFi connectivity issues inhibit such activity.

Load Management Credit.

Customers shall receive a monthly billing credit only for the number of peak period or emergency demand reduction events called and participated in per month for each central electric cooling/heat pump unit controlled during the billing months of May to September, up to a maximum of 15 events per year. Monthly billing credits will be calculated and applied to customer bills at $2.40 per event called and participated in, subject to the annual 15 event maximum.

Customers that opt out of demand reduction events shall not be eligible for a billing credit for those events.

Customers shall not be eligible for load management credits if the Company's load management platform cannot manage customer loads during peak period events due to issues such as customer internet and/or WiFi outages or lack of connectivity.

The Company, at its sole discretion, reserves the right to remove enrolled customers from the program and their eligibility for bill credits under the program due to consistent and iterative opt out of demand response events but only if opt outs exceed fifty percent of the coincident peak period demand reduction events called during any annual program period. The Company shall provide billing credits proration up to and including events called and participated in by the Customer.

Such credit shall not reduce the customer's bill below the minimum charge as specified in the tariff under which the customer takes service.

Contract.

Participating customers must agree to participate for an initial period of one (1) year or one peak period season period (defined as May through September) as applicable and thereafter may discontinue participation by contacting the Company.

(Cont'd on Sheet No. 42.2)

RIDER H.E.M.
(Home Energy Management Rider)
(Cont'd from Sheet No. 42.1)

Equipment.

The customer will furnish and install, smart, WiFi enabled and broadband internet connected load control equipment, and, if necessary, an auxiliary communicating device. All equipment will be owned and maintained by the customer, from installation, throughout program participation, and until such time as the Home Energy Management Program is discontinued or the customer requests to be removed from the program after completing the initial period set forth above. At that time, the Company will cease both its energy management and control of the program equipment, along with any auxiliary communicating devices, and the Load Management Credit provided for by the program.

Should the customer lose, damage, or not maintain the required WiFi and internet connectivity of the load control devices or auxiliary communicating equipment, the Company will contact the customer in an attempt to reinstate program required equipment functionality. If such attempts by the Company do not facilitate reinstatement of the program required functionality, the Company will remove the customer from the program and will cease the Load Management Credit. Customer will receive credits for any events called and participated in by the customer prior to removal from the program.

Special Terms and Conditions.

This rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions.

The Company shall not be required to offer the program to customers who cannot maintain WiFi and internet connectivity for required functionality of the load control equipment, or if the continued operation of the program cannot be justified for reasons such as: customer preference, electric power market conditions, technological functionality and limitations, safety concerns, or abnormal customer premise conditions, including vacation or other limited occupancy residences.

The Company and its authorized agents shall confirm installation through WiFi and internet connectivity of the load control device(s). In the event full WiFi and internet connectivity is not available, the Company may require access to inspect the load control device(s) and/or provide the customer thirty (30) days to successfully restore or provide full WiFi and internet connectivity. Should full WiFi and internet connectivity not be available after 30 days, the customer will be promptly removed from the program and the Energy Management Credit discontinued until such time as the Company is able to gain the required access. The Company shall not be responsible for the repair, maintenance or replacement of any customer-owned equipment.

Customer-specific information within data collected during the course of this energy management and control program will be held as confidential and data presented in any analysis will protect the identity of the individual customer.

(Cont'd on Sheet No. 42.3)

RIDER H.E.M.
(Home Energy Management Rider)
(Cont'd from Sheet No. 42.2)

Load Management Programs

Availability of Service

Available on a voluntary basis for qualifying customers with an AMI meter receiving residential electric service, subject to the enrollment caps listed below for each program. Customers that do not currently have an AMI meter may request one in order to participate in this tariff.

Customers are not eligible to take service under the Company's Residential Time of Day 2 tariff or Critical Peak Pricing tariff while enrolled and participating in any load management program offered under this Rider. Customers that enroll and participate in the AMI DLC load management programs are not eligible to enroll and participate in the Customer Engagement Demand Response Program for the same program year. Customers may enroll and participate in more than one AMI direct load control (DLC) load management program offered under this Rider but are not eligible to enroll and participate in the BYOD thermostat load management program for the same program year.

For non-owner occupied multi-family dwellings, the Company may require property owner authorization on behalf of customers for the Company or its authorized agents to install any of the required load control equipment and, if necessary, any required supplemental communication devices or auxiliary communicating devices such as remote sensors or additional control devices. Customers will not be eligible for this rider if the property owner does not allow installation of such equipment.

Program Option Descriptions

Home Energy Management – AMI HVAC Direct Load Control (DLC) Program

To participate, customers must meet program specific qualification criteria as stated in program specific requirement documents as provided by the Company. Qualified customers must agree, either in writing or via verbal recording, to allow the Company or its authorized agents to install, operate, and maintain the required load control switch at or near the customer's air conditioner or heat pump central unit(s). Qualified customers must also allow the Company or its authorized agents access, as required and appropriate, to such customer owned equipment for the purposes of program related installation, operation, maintenance, and data collection.

The Company plans to initially utilize an adaptive cycling strategy of the central electric cooling unit(s) during summer months, which can result in a 50% cycling strategy or higher but will be dependent upon an assessment of customer comfort impact. Other cycling strategies may be employed and evaluated to determine the strategy that optimizes load reduction without significantly affecting customer comfort.

Enrollment maximum: 5,458 customers

(Cont'd on Sheet No. 42.4)

RIDER H.E.M.
(Home Energy Management Rider)
(Cont'd from Sheet No. 42.3)

Residential AMI Electric Water Heat Direct Load Control Program

To participate, customers must meet program specific qualification criteria as stated in program specific requirement documents as provided by the Company. Qualified customers must agree to participate, either in writing or via verbal recording, in the AMI DLC Program to allow the Company or its authorized agents to install, operate, and maintain the required load control program switch at or near the customer's electric resistance element water heater unit(s). Qualified customers must also allow the Company or its authorized agent's access, as required and appropriate, to such customer owned equipment for the purposes of program related installation, operation, maintenance, and data collection.

The Company plans to initially allow qualified participating customers to choose one of three levels of electric hot water heater unit load management approach, Form 1, Form 2, or Form 3. Form 1 is minimally invasive to hot water control cycling strategy, Form 2 is moderately invasive hot water heater control cycling strategy, and Form 3 is the most invasive hot water heater control cycling strategy. Other cycling strategies may be employed and evaluated to determine the strategy that optimizes load reduction without significantly affecting customer comfort, but with customer advance agreement.

Enrollment maximum: 1,738 customers

Residential Customer Engagement Demand Response Program

This program requires customer self-action to manage their own end-use consumption during periods of peak usage notification from the Company.

To participate, customers must meet program specific qualification criteria as stated in program specific requirement documents as provided by the Company. Qualified customers must agree to participate, either in writing or via verbal recording, in the Customer Engagement Demand Response Program.

Additional customer requirements:

- Have an active I&M AMI data portal account, or otherwise engaged through one of the AMI residential usage information offerings (e.g. Weekly AMI Report, or WAMI);
- Primary residence is located within I&M service territory;
  - Single family residence that is not electrically served and metered as part of a master metering arrangement;
  - Multi-family residence that is not electrically served and metered as part of a master metering arrangement.

(Cont'd on Sheet No. 42.5)

RIDER H.E.M.
(Home Energy Management Rider)
(Cont'd from Sheet No. 42.4)

And, any of the following:

- Subscription to broadband internet services with a valid email address capable of receiving email demand response event notification;
- Smart cell phone with a valid email address capable of receiving email demand response event notification;
- Smart cell phone with an I&M app capable of receiving text and/or push demand response event notification;

Enrollment maximum: 63,289 customers.

Except for the Residential Customer Engagement Demand Response Program, the Company will utilize a load management software platform to operate and control enrolled load control devices primarily to reduce customer's demand and use. The Company's load management platform will primarily operate to optimize and/or reduce demand use through either peak period use load reduction management techniques or load shaping to achieve optimum and efficient Customer demand use of electricity.

Program demand reduction/load management activities can occur during coincident peak and non-coincident peak demand periods according to Company and PJM system load forecasting techniques. Coincident peak, non-coincident peak, and emergency demand reduction/load management activities will be coordinated during electric power system peak load periods determined according to both I&M system and PJM system requirements. The Company plans to utilize load management activities focused primarily on managing enrolled and active load control devices during peak and emergency conditions and will seek to minimize customer comfort impact during the period of peak demand load management activity to the extent practical. Peak period demand load control events can occur based on I&M and/or PJM system need, as determined by the Company

Peak period load management events shall curtail customer load based on system need, at the sole discretion of the Company, during the months of May through September and shall not exceed 15 events per year with no single event lasting more than six (6) consecutive hours and no more than one event per day.

The Company may communicate events to Customers through the program's load management platform, via a smart phone application push notification, or via email or other electronic notification means. The customer may opt out of a Company planned load management event by providing the Company appropriate notice through the requisite and identified program opt out means of communication.

(Cont'd on Sheet No. 42.6)

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 42.6**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

RIDER H.E.M.
(Home Energy Management Rider)
(Cont'd from Sheet No. 42.5)

Load Management Credit

Customers shall receive a monthly billing credit only for the number of peak period or emergency demand reduction events called and participated in per month for each load management device controlled during the billing months of May to September, up to a maximum of 15 events per year. Monthly billing credits will be calculated and applied to customer bills according to the Home Energy Management Load Management program enrolled in, per event called and participated in, subject to the annual 15 event maximum.

Home Energy Management – AMI HVAC Direct Load Control (DLC) Program

$2.40 per load management event called and participated in, subject to the annual 15 event maximum. Customers that opt out of demand reduction events shall not be eligible for a billing credit for those events.

Home Energy Management - AMI Electric Water Heat Direct Load Control Program

$0.80 (Form 1), $1.00 (Form 2) or $1.10 (Form 3) per load management event called and participated in, subject to the annual 15 event maximum. Credit is determined according to the demand reduction Form the customer enrolls in. Further information is available in the program requirements. Customers that opt out of demand reduction events shall not be eligible for a billing credit for those events.

Home Energy Management - Customer Engagement Demand Response Program

$1.00 per kWh of verified reduced energy consumption per load management event called and participated in, subject to the annual 15 event maximum.

If the customer does not reduce load as determined by the Company based on their hourly event usage measured at the AMI electric meter for the premise enrolled in this Program, that customer will be considered as opt out of the load control event and therefore will not be paid a demand response event bill credit.

The Company, at its sole discretion, reserves the right to remove enrolled customers from the program, along with their eligibility for bill credits under the program, due to consistent and iterative opt out of demand response events but only if opt outs exceed fifty percent of the peak period demand reduction events called during a program year. The Company shall provide billing credits proration up to and including events called and participated in by the Customer.

Such credit shall not reduce the customer's bill below the minimum charge as specified in the tariff under which the customer takes service.

(Cont'd on Sheet No. 42.7)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC BILLS RENDERED
ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

RIDER H.E.M.
(Home Energy Management Rider)
(Cont'd from Sheet No. 42.6)

Contract

Participating customers must agree to participate for a period of two (2) years or two peak period season periods (defined as May through September) as applicable and thereafter may discontinue participation by contacting the Company.

Special Terms and Conditions.

This rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions.

Customer-specific information within data collected during the course of implementation for any of the load management programs offered under this tariff will be held as confidential and data presented in any analysis will protect the identity of the individual customer.

RIDER W.E.M.
(Work Energy Management Rider)

Availability of Service

Available on a voluntary basis to customers taking firm service from the Company under Tariffs G.S., G.S.-TOD, L.G.S., L.G.S.–TOD, G.S.-TOD2, I.P., C.S.-IRP2, M.S., W.S.S., or E.H.G. who meet the load management program requirements under this rider. The Company's Work Energy Management (W.E.M.) program provides participating customers an opportunity to respond voluntarily by reducing consumption and receiving payment for such reduction during times of peak period consumption or high location marginal price (LMP) cost, according to the load management program enrolled in under this rider.

Depending upon the program enrolled in under this rider, for non-owner occupied commercial and industrial buildings, the Company may require customers to obtain permission from the building owner to install the required load control equipment and, if necessary, any required supplemental communication devices or auxiliary communicating devices such as remote sensors or additional control devices. Customers will not be eligible for this rider if the owner does not allow installation of such equipment or does not agree to program terms and requirements through a contractual agreement.

Customers participating in this rider are not eligible for enrollment in any other Company or PJM Interconnection, L.L.C. RTO (PJM) demand response program or peak period pricing tariff. Notwithstanding anything to the contrary in Rider D.R.S.1, customers currently served under Rider D.R.S.1 will be eligible to switch to service under Rider W.E.M. once their registration with PJM under Rider D.R.S.1 expires on May 31 of a given year, provided the customer provides written notice to the Company by May 1 of that year. This provision does not address the enforceability of any additional contractual obligation the customer may have to a Curtailment Service Provider (CSP) if the customer has elected to use the services of a CSP under Rider D.R.S.1.

Conditions of Service

(1) The Company reserves the right to make changes to this rider in order to continue effective program operation.
(2) An AMI meter is required for eligibility of programs under this rider.
(3) The Company will inform the participant regarding the communication process and timing required to participate in this program and rider. The customer is ultimately responsible for receiving and acting upon notifications as part of this program and rider.
(4) Participants shall not receive credit for any curtailment periods to the extent that the customer's program managed load is already reduced due to a planned or unplanned outage as a result of vacation, renovation, repair, refurbishment force majeure, strike, economic conditions, or any event other than the Company's program that causes the customer's energy consumption to fall outside of that considered normal operating conditions.

(Cont'd on Sheet No. 43.1)

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 43.1

RIDER W.E.M.
(Work Energy Management Rider)

(Cont'd from Sheet No. 43)

Load Management Option Terms

According to the load management program enrolled in under this rider, to participate, customers, or their authorized agents, must allow the Company and its authorized agents to install program compliant load control equipment as necessary and appropriate, or to electronically connect and electronically communicate to program compliant customer-owned systems and devices through the customer's internet connection. Customer shall allow the Company and its authorized agents to connect that equipment to Company owned communication equipment, and maintain both the load control equipment and associated communication equipment connections for the duration of the program. Also, if necessary, and appropriate, the customer must allow the Company to install any program required auxiliary communicating devices to further facilitate the program's management and control of certain customer loads and/or customer sited electric power supply equipment as deemed necessary and appropriate for program operation. The program will initially, but not exclusively, focus on the customer's end-use lighting and HVAC unit(s) loads for program remote control and management.

Load control equipment available to participate in the program will be jointly determined and agreed upon by the Company, the Company's authorized agents and the customer. All such devices shall be installed at a time that is consistent with the orderly and efficient deployment of this program. The load control equipment must comply with the Company's approved list of devices. The customer must allow the Company to interface both through software algorithms and hardware devices to existing customer end-use load and communication equipment. The Company and its authorized agents may perform an initial site survey in order to fully determine and assess the viability of customer end use load and electric energy usage and consumption patterns to validate customer participation and program effectiveness. The Company and its authorized agents will maintain any Company owned program equipment installed on customer premises for the duration of the customer's participation of the program.

At its option, according to the load management program offered under this rider, the Company and its authorized agent will provide customer access and use of program energy management and control software for the duration of the customer's participation in the program.

Small Business AMI Direct Load Control (DLC) Program
To participate, customers must meet program specific qualification criteria as stated in program specific requirement documents as provided by the Company and must have an electric account under an eligible tariff with an AMI meter installed by the Company at the premise in which the load management device is used and active. Customers must agree to install program compliant WiFi enabled load control equipment and/or energy management system(s), connect that equipment and system(s) to their WiFi broadband internet connection, and maintain that connection with continuous operation and availability for the duration of the program annual operational period defined as May through September of each program year. All such devices shall be installed at a time that is consistent with the orderly and efficient deployment of this program. Customer owned devices must comply with the Company's approved list of devices.

(Cont'd on Sheet No. 43.2)

RIDER WEM
(Work Energy Management Rider)

(Cont'd from Sheet No. 43.1)

Initially, the Company will determine and provide a program WiFi connected energy management system and device compliant list, but as technology, device capability, and the program's load management platform evolves, the Company may allow and provide for additional approved devices. The Company may provide for and determine the appropriate level of customer equipment rebates, as needed and required, in order to facilitate customer installation and ownership of the required equipment as part of this load management program.

For thermostat device control, the Company plans to initially utilize a pre-cooling and 2 or 4 degree temperature setback cycling strategy of the central electric cooling unit(s) during summer months. Other cycling strategies may be employed and evaluated to determine the strategy that optimizes load reduction without significantly affecting customer comfort.

The Company will arrange for its preferred Program business partner DLC measures and EMS to be made available for installation and customer ownership as a Program incentive. I&M will also arrange and provide for Program measures and systems to be installed as part of the Program. Customers will own all Program measures and systems once provided by the Program, and will continue ownership, responsibility for future maintenance, and program compliance after the Program concludes. After Program completion, Program customers must agree to continue participation in the Company's Work Energy Management tariff demand response offering for a minimum of two (2) summer cooling seasons.

Small Business Direct Load Control Program Eligibility

Small business customers with at least one existing and operational central air conditioning and/or heat pump units located at the same commercial business property that are identified and qualified as meeting the following criteria:

- A maximum of 40 kW in monthly peak demand usage as measured by the Company's electric meter;
- An AMI meter and telecommunication system installed by I&M sufficient to support the technology needs of this program;
- At least one HVAC equipment measure available for demand response control through wireless, remote capability including:
  - o Compliant Wi-Fi connected thermostats in which the Customer allows the Company to vary the air conditioner compressor motor or heat pump compressor motor run time for demand response events;

(Cont'd on Sheet No. 43.3)

RIDER WEM
(Work Energy Management Rider)

(Cont'd from Sheet No. 43.2)

  - o Compliant Wi-Fi connected variable control air flow motors with carbon dioxide (CO_2) or occupancy sensors that the Customer allows the Company to vary for demand response events;

- Customer-owned broadband internet services;
- Customer-owned and program compliant remote control energy management system (EMS) and/or remote, electronic means of access to program controlled DR measures such as through a program compliant thermostat manufacturer API arrangement.
  - o Customer-owned Company business partner EMS DR measure and equipment system preferred
- Commercial business hours of operation identified as overlapping with typical Company and PJM summer cooling season peak periods (e.g. weekday, noon to 8 pm) where high probability exists for HVAC system typical operation.

Small Business Direct Load Control Program Load Management Events

Load management (i.e. peak reduction, non-emergency) events will be called at the discretion of the Company, with up to 15 events per year. Emergency events will be at the discretion of PJM as defined in PJM Manual 13 – Emergency Operations, with up to 10 events per PJM planning year.

Small Business Direct Load Control Program Equipment

The Customer will furnish and install program compliant WiFi enabled and broadband internet connected load control energy management system(s) and equipment, and, if necessary, an auxiliary communicating device. All equipment will be owned and maintained by the customer, from installation, throughout program participation, and until such time as this program is discontinued or the customer requests to be removed from the program after completing the initial period set forth above. At that time, the Company will cease both its energy management and control of the program equipment, along with any auxiliary communicating devices, and the Load Management Credit provided for by the program.

Should the customer lose, damage, or not maintain the required WiFi and internet connectivity of the load control devices or auxiliary communicating equipment, the Company will contact the customer in an attempt to reinstate program required equipment functionality. If such attempts by the Company do not facilitate reinstatement of the program required functionality, the Company will remove the customer from the program and will cease the Load Management Credit. Customer will receive credits for any events called and participated in by the customer prior to removal from the program.

The Company shall not be required to offer the program to customers who cannot maintain WiFi and internet connectivity for required functionality of the load control equipment, or if the continued operation of the program cannot be justified for reasons such as: customer preference, electric power market conditions, technological functionality and limitations, safety concerns, or abnormal customer premise conditions, including any limited business operation premises.

(Cont'd from Sheet No. 43.4)

RIDER WEM
(Work Energy Management Rider)

(Cont'd from Sheet No. 43.3)

The Company and its authorized agents shall confirm installation through WiFi and internet connectivity of the load control device(s). In the event full WiFi and internet connectivity is not available, the Company may require access to inspect the load control device(s) and/or provide the customer thirty (30) days to successfully restore or provide full WiFi and internet connectivity. Should full WiFi and internet connectivity not be available after 30 days, the customer will be promptly removed from the program and the Load Management Credit discontinued until such time as the Company is able to gain the required access. The Company shall not be responsible for the repair, maintenance or replacement of any customer-owned equipment.

Enrollment Maximum: 959

Small Business Direct Load Control Program Load Management Credit

$2.40 per event called and participated in during the summer months of May, June, July, August and September for each air-conditioning/heat pump unit/variable air flow motor participating in the called events. In the case where a customer has two or more HVAC units, or measures, participating in an event, the customer will receive a bill credit, as described above, for each HVAC unit or measures completing the participation in the event.

Non-Small Business Direct Load Control Program Load Management

The Company will utilize a Company owned, managed, and operated energy management software platform that will operate and control customer load control devices to reduce customer's demand and energy use. The Company's energy management platform may operate to optimize energy use through load shaping to achieve optimum and efficient customer use of electricity. Energy reductions will be coordinated during electric power system peak load periods determined at the sole discretion of the Company. Non-emergency energy management events can occur for up to 800 hours per year with no single event lasting more than six (6) consecutive hours. The Company plans to initially target energy management events for up to 487 hours per year but reserves the right to undertake energy management events up to 800 hours per year according to, and appropriate for, individual Customer load profiles and business operating conditions and requirements. The Company and its authorized agent may utilize a load shaping strategy; however, other strategies may be employed and evaluated to determine the strategy that optimizes energy reduction without significantly affecting predetermined customer business preferences, operating conditions, and requirements.

(Cont'd on Sheet No. 43.5)

RIDER W.E.M.
(Work Energy Management Rider)

(Cont'd from Sheet No. 43.4)

Energy management events will be called according to and in alignment with predetermined customer preferences and business requirements. Non-emergency energy management events shall not exceed 800 hours per year and depend upon individual customer load profile and energy use footprint.

The customer may opt out of a non-emergency energy management event through the program energy management system software platform or by contacting the Company and/or its authorized agent personnel. The Company's energy management software algorithm will facilitate and accept the event opt out. The Company will communicate events to customers through the energy management platform and via other means required by the customer. The method of event notification may change as determined by the Company and in conjunction with customers, to email or other electronic notification means.

Non-Small Business Direct Load Control Program Load Management Credit

Customers will only receive either a monthly or annual payment, as mutually agreed upon by each customer and the Company, based on the Hourly Curtailed Energy and 90% of the applicable LMP (Day-Ahead) established by PJM (including congestion and marginal losses) . Energy Management Credits will vary based on market hourly energy prices and program effectiveness as determined by the Company and its authorized agent. No payment will be made to customers who opt out of energy management activity for the period of time that the customer opted out for. The Company may assess a penalty to customers who opt out of Company determined system emergency conditions at a penalty rate consistent with and based upon the Company's cost to provide such opt out energy during emergency conditions.

Non-Small Business Direct Load Control Program Load Management Equipment

The Company, and its authorized agent, will furnish and install load control equipment, and, as necessary, auxiliary communicating devices at the customer's premise. All equipment will be owned and maintained by the Company and its authorized agent until such time as the Work Energy Management Program is discontinued or the customer requests to be removed from the program after completing the initial period of three (3) years. At that time, the Company will cease both its energy management and control of the load control equipment and any auxiliary communicating devices, remove Company owned program equipment, and cease annual customer incentives paid by the program.

Should the customer lose, damage, or not allow the Company and its authorize agent to operate and maintain the required load control devices and auxiliary communicating equipment, the Company and its authorized agent will contact the customer in an attempt to re-instate program required equipment functionality. If such attempts by the Company do not facilitate reinstating the program required functionality, the Company will remove the customer from the program, remove Company owned equipment, and will cease the program customer incentive payments.

(Cont'd on Sheet No. 43.6)

RIDER W.E.M.
(Work Energy Management Rider)

(Cont'd from Sheet No. 43.5)

Non-Small Business Direct Load Control Program Load Management Contract

Participating customers must agree to participate for an initial period of not less than three (3) years and shall remain a participant thereafter until either party gives at least six months' written notice to the other of the intention to discontinue participation under the terms of this rider.

Non-Small Business Direct Load Control Program Load Management Curtailed Energy

For each curtailment period, Curtailed Energy shall be defined as the difference between the customer's Customer Baseline Load (CBL) calculation and the customer's actual energy used during each hour of the curtailment period.

Customer Baseline Load Calculation

The Company will utilize the energy management platform data and Company billing system data to determine a Customer Baseline Load (CBL) for each hour corresponding to each curtailment event hour in order to determine the amount of energy reduced for Energy Management Credit purposes. The CBL shall accurately reflect the customer's normal consumption profile, to the extent possible. The Company will provide to each WEM program customer how the CBL is determined.

Special Terms and Conditions

This rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions.

The Company shall not be required to offer the program to customers when the Company and its authorized agent cannot maintain the required functionality of the load control equipment, or if the continued operation of the program cannot be justified for reasons such as: customer preference, electric power market conditions, technological functionality and limitations, safety concerns, or abnormal customer premise conditions, including vacation or other limited occupancy residences.

The Company and its authorized agents shall be permitted access to the customer's premises during normal business hours to confirm installation and connectivity of the load control device(s). In the event the Company requires access to load control device(s), and the customer does not provide such access within 30 days of the request, the Company may discontinue the Energy Management Credit until such time as the Company is able to gain the required access. The Company shall not be responsible for the repair, maintenance or replacement of any customer-owned equipment.

The Company will collect data during the course of this energy management and control program. Customer-specific information will be held as confidential and data presented in any analysis will protect the identity of the individual customer.

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 44

APPLICABLE SURCHARGES AND RATE ADJUSTMENTS

Commission-approved surcharges and rate adjustments applicable to standard service customers:

Applicable Surcharges and Rate Adjustments	Sheet No.
Demand-Side Management / Energy Efficiency Program Cost Rider	45
Fuel Cost Adjustment Rider	46
Environmental Cost Rider	47
Off-System Sales Margin Sharing / PJM Cost Rider	48
Life Cycle Management Rider	49
Resource Adequacy Rider	50
Phase-In Rate Adjustment	51
Solar Power~~Renewable Projects~~ Rider	52
~~AMI Cost Rider~~	~~53~~
TAX Rider	53~~54~~

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO. 45576

DEMAND-SIDE MANAGEMENT / ENERGY EFFICIENCY PROGRAM COST RIDER

Demand-side Management / Energy Efficiency Program Cost Rider (DSM/EE) surcharge allows the Company to recover costs associated with the Company's DSM/EE Program costs approved by the Commission. All customer bills subject to the provisions of this rider shall be adjusted by the Demand-Side Management/Energy Efficiency Program Cost Rider adjustment factor per Billing Month as follows:

	Non-Opt Out Customers (Group N)	Pre 2021 Opt Out Customers (Group H and Group C)	2021 Opt Out Customers (Group F)
Tariff Class	¢/kWh	¢/kWh	¢/kWh
RS, RS-TOD, RS-TOD2,RS-OPES, RSD, RS-PEV and RS-CPP	X.XXXX	N / A	N / A
GS (Excluding Unmetered), GS-TOD, GS-TOD2, GS-PEV, GS-CPP, LGS, LGS-TOD, IS, EHG, MS, WSS, SLS, ECLS, SLC, SLCM and FW-SL	X.XXXX	X.XXXX	X.XXXX
~~L.G.S.~~	~~X.XXXX~~	~~X.XXXX~~	~~X.XXXX~~
IP, CS-IRP2	X.XXXX	X.XXXX	X.XXXX

(Cont'd on Sheet No. 45.1)

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FORT WAYNE, INDIANA

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ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

DEMAND-SIDE MANAGEMENT / ENERGY EFFICIENCY PROGRAM COST RIDER

(Cont'd from Sheet No. 45)

OPT-OUT OPTION FOR QUALIFYING COMMERCIAL AND INDUSTRIAL CUSTOMERS

A. Definitions

The following definitions are applicable to the opt-out provisions of Demand-Side Management/Energy Efficiency Program Cost Rider only:

Single Site: A Single Site shall be defined as contiguous property unless aggregation of multiple delivery points is specifically permitted under the applicable approved Rate Schedule as of April 1, 2014.

Qualifying Customer: A customer that receives electric service under an approved Rate Schedule at a Single Site constituting more than one megawatt of electric capacity.

Qualifying Load: A Single Site with at least one meter constituting more than one megawatt of electric capacity for any one billing period within the previous 12 months prior to the Qualifying Customer's opt out notification to the Company. Such demand shall be measured with a demand meter.

Energy Efficiency Program: Commission approved energy efficiency program applicable to the approved Rate Schedule of a Qualifying Customer.

Energy Efficiency Program Costs: Costs recovered under this Rider, including program costs, net lost revenues and incentives, and reconciliation of applicable costs as approved by the Commission.

(Cont'd on Sheet No. 45.2)

DEMAND-SIDE MANAGEMENT / ENERGY EFFICIENCY PROGRAM COST RIDER

(Cont'd from Sheet No. 45.1)

B. Opt Out Option for Qualifying Customers

A Qualifying Customer may elect to opt out of participation in the Company's Energy Efficiency Program for Qualifying Load. If a customer has a Single Site with Qualifying Load, it may opt out all accounts receiving service at that Single Site. Such accounts will be opted out provided the customer identifies the accounts in the customer's notice to the company of its election to opt out. Once a customer is determined to be a Qualifying Customer, the Company will not revoke the Qualifying Customer's qualification at a later date. For customers that are billed on a MVA and not on MW basis, I&M will use 1MVA as an equivalent for 1 MW to determine if the status of a Qualifying Customer.

New customers that do not sign a demand contract will need to have and demonstrate Qualifying Load in order to qualify consistent with the Notification and Effective Date provisions below. New customers signing a demand contract with Qualifying Load may complete the form to opt out of the program immediately. New customers who qualify (Group C) will initially be billed at a DSM/EE adjustment factor of 0.0000¢ per kWh, subject to modification in future proceedings.

C. Notification and Effective Date

A customer seeking to opt out of the Company's Energy Efficiency Program shall provide written notice of its desire to opt out to the Company. If not done at the initial notice of opt out, the customer shall fill out the appropriate form as requested by the Company to complete the registration of the accounts subject to the opt out request, the notice date of the customer's opt out will be the date of its initial notice. A Qualifying Customer that notifies the Company on or before June 1, 2014 of its decision to opt out of participation in the Company's Energy Efficiency Program will be exempted from the Energy Efficiency Program effective the first billing date in July 2014. A Qualifying Customer that notifies the Company of its decision to opt out of participation in the Company's Energy Efficiency Program after June 1, 2014 but on or before November 15, 2014 of its intention to opt out of participation in the Energy Efficiency Program shall have an opt out effective date of January 1, 2015. Thereafter, a Qualifying Customer must provide notice to the Company of its intention to opt out of participation in the Company's Energy Efficiency Program by November 15 to opt out effective January 1 of the following calendar year. A customer does not need to opt out each year. All Qualifying Customers providing notice under this section shall be subject to the recovery of Energy Efficiency Program Costs as described below.

D. Energy Efficiency Program Costs

Qualifying Customers remain liable for Energy Efficiency Program Costs that accrued or were incurred, or relate to energy efficiency investments made before the date on which the opt out is effective, regardless of the date on which such costs are included in the Energy Efficiency Program for recovery. Such costs may include costs related to evaluation, measurement and verification ("EM&V") required to be conducted after a Qualifying Customer opts out on projects completed under an Energy Efficiency Program while the Qualifying Customer was a participant. In addition, such costs may include costs required by contracts executed prior to April 1, 2014 but incurred after the date of the Qualifying Customer's opt out. However, these costs shall be limited to fixed, administrative costs, including costs related to EM&V. A Qualifying Customer shall not be responsible for any program costs such as the payment of energy efficiency rebates or incentives, incurred following the effective date of its opt out, with exception of incentives or rebates that are paid on applications that have not closed out at the effective date of its opt out.

(Cont'd on Sheet No. 45.3)

DEMAND-SIDE MANAGEMENT / ENERGY EFFICIENCY PROGRAM COST RIDER

(Cont'd from Sheet No. 45.2)

E. Opt Out DSM/EE Factor

A separate Opt Out Energy Efficiency Program Factor will be calculated and made applicable to Qualifying Customers electing to opt out of participation in the Company's Energy Efficiency Program. The Opt Out Factor will be calculated to recover only applicable Energy Efficiency Program Costs. Any over- or under- recovery of costs for the time period during which the Qualifying Customer was participating in Energy Efficiency Programs shall be captured by the reconciliation and recovered or refunded to the Qualifying Customer through the reconciliation factor of the Opt Out Factor. Specifically,

(1) For the period of January 1, 2015 through December 31, 2015, a Qualifying Customer that opts out of participation effective July 1, 2014 will pay:

- (a) Program Reconciliation costs including Shared Savings (if applicable) for January 2013 through June 2014;
- (b) Lost Revenue Projections for July 2014 through December 2015 (which include all lost revenues to be collected during the period) for measures installed while the Qualifying Customer was participating in the Energy Efficiency Program;
- (c) Lost Revenue Reconciliation from January 2013 through June 2014;

In 2016, and the years after, the factor will be updated for any remaining EM&V costs and to reconcile and forecast any remaining net lost revenues.

(2) For the period of January 1, 2015 through December 31, 2015, a Qualifying Customer that opts out of participation effective January 1, 2015 will pay:

- (a) Program Reconciliation costs including Shared Savings (if applicable) for January 2013 through December 2014;
- (b) Program Costs Forecast including Shared Savings (if applicable) for July –December 2014;
- (c) Lost Revenue Projections for July 2014 through December 2015 (which include all lost revenues to be collected during the period) for measures installed while the Qualifying Customer was participating in the Energy Efficiency Program;
- (d) Lost Revenue Reconciliation from January 2013 through June 2014;

In 2016, and the years after, the factor will be updated for any remaining EM&V costs and to reconcile and forecast any remaining Net Lost Revenues.

(3) A Qualifying Customer that opts out of participation effective January 1 of any subsequent year (beyond 2015) will pay:

- (a) Outstanding Program Reconciliation costs including Shared Savings (if applicable);
- (b) Program Costs Forecast including Shared Savings (if applicable) for the prior July – December period;
- (c) Lost Revenue Projections for the July of the opting out year through December of the following year (which include all lost revenues to be collected during the period) for measures installed while the Qualifying Customer was participating in the Energy Efficiency Program;
- (d) Lost Revenue Reconciliation from January of the calendar year prior to opting out through June of the effective opt out year.

(Cont'd on Sheet No. 45.4)

DEMAND-SIDE MANAGEMENT / ENERGY EFFICIENCY PROGRAM COST RIDER

(Cont'd from Sheet No. 45.3)

In subsequent years beyond the effective opt out year, and the years after, the factor will be updated for any remaining EM&V costs and to reconcile and forecast any remaining Net Lost Revenues.

If the Company makes subsequent changes to the allocation of Energy Efficiency Program Costs, Qualifying Customers that opted out of participation will continue to pay those costs based on the allocation in effect at the time of the notice of opt out. Any reconciliation of Energy Efficiency Program Costs will likewise be allocated in the same manner in effect at the time of the Qualifying Customer's notice of opt out.

F. Opt-In

A Qualifying Customer may opt back in to participation in the Company's Energy Efficiency Program by providing notice by November 15 of the year prior to its requested opt in date. If not done at the initial notice to opt-in, the customer shall fill out the appropriate form as requested by the Company to complete the registration of the accounts subject to the opt-in request. The opt in shall be effective January 1 of the year following the notice. If a Qualifying Customer opts back in to participation in the Company's Energy Efficiency Program, such Qualifying Customer must be requalified to opt out again. If a Qualifying Customer opts back in to participation in the Company's Energy Efficiency Program, that Qualifying Customer must participate in the associated Energy Efficiency Program for at least three years, and may only opt out effective January 1 of the year following the third year of participation. A Qualifying Customer may elect to opt out again before the end of the three year period, but, in such event, remains liable for, and must continue to pay the Demand-Side Management/Energy Efficiency Program Cost Rider as if it were still participating in the Company's Energy Efficiency Program for the remainder of the three year period. If a Qualifying Customer elects to opt back out after the three year period, that Qualifying Customer shall be responsible for Demand-Side Management/Energy Efficiency Program Costs in the same manner as other customers who have opted out consistent with the provisions contained herein.

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 46**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

FUEL COST ADJUSTMENT RIDER (FAC)

The energy charges set forth in all rate schedules and those energy charges that are either included in the capacity or demand charges of such rate schedules or in the minimum billings under such rate schedules shall be increased or decreased, to the nearest 0.001 mill ($.000001) per kWh, in accordance with the following adjustment factor:

$$\text{Adjustment Factor} = \frac{F}{S} - \$\,0.0131100 \text{ per kWh}$$

where:

1. "F" is the estimated expense of fuel based on a six-month average cost beginning with the month immediately following the current billing cycle month and consisting of the following costs:

   (a) the average cost of fossil and nuclear fuel consumed in the Company's own plants, such cost being only those items listed in Account 151 and Account 518 (exclusive of spent nuclear fuel disposal costs which will be determined as specified in (e) below), respectively, of the Federal Energy Regulatory Commission's Uniform System of Accounts for Class A and B Public Utilities and Licensees;

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below;

   (c) the net energy cost, exclusive of capacity or demand charges, of energy purchased on an economic dispatch basis, and energy purchased as a result of a scheduled outage, when the costs thereof are less than the Company's fuel cost of replacement net generation from its own system at that time; less

   (d) the cost of fossil and nuclear fuel recovered through intersystem sales including fuel costs related to unit power sales, economy energy sales, and other energy sold on an economic dispatch basis;

   (e) the total Company amounts of spent nuclear fuel disposal costs as determined in I.U.R.C. Cause No. 45576 .

   (f) wind related cost approved by the Commission for recovery within this rider,

   (g) other revenues or costs approved by the Commission for recovery

(Cont'd on Sheet 46.1)

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EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

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IN CAUSE NO. 45576

FUEL COST ADJUSTMENT RIDER (FAC)

(Cont'd from Sheet 46)

2. "S" is the estimated kilowatt-hour sales for the same estimated period set forth in "F", consisting of the net sum in kilowatt-hours of:

   (a) net generation
   (b) purchases
   (c) interchange-in, less
   (d) intersystem sales
   (e) energy losses and Company use

The adjustment factor as computed above shall be further modified to allow the recovery of utility receipts taxes and other similar revenue based tax charges occasioned by the fuel cost adjustment revenues.

The fuel cost charge shall be further modified to reflect the difference between incremental fuel cost billed and incremental fuel cost actually experienced not less than during the latest six calendar months for which actual fuel costs were available at the time of the filing of the application for a change in the fuel cost charge.

The adjustment factor as calculated above will be applied to all billing kilowatt-hours for those tariffs which have as part of their tariff a fuel cost adjustment. This would include any other revenues or costs approved to be included in this rider that are not part of the F/S calculation as described above.

Adjustment factors to be applied to the following billing cycle month:

October 2021 through March 2022	x.xxxxxx/kWh	Rates to be determine in
April 2022 through September 2022	x.xxxxxx/kWh	Semi-Annual FAC filings.

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EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

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I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 47**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ENVIRONMENTAL COST RIDER (ECR)

The Environmental Cost Rider (ECR) surcharge allows the Company to recover environmental related costs including investments in clean coal technology projects including consumable products and state and federal emission allowances approved by the Commission.

1. Upon the effective date of this tariff sheet, and continuing through the first billing cycle of January 2023, this Rider shall also recover consumables and allowance costs incurred through December 7, 2022 associated with Rockport Unit 2.
2. Upon approval of revised Phase-In Rate Adjustment Rates in January 2023, this Rider shall also recover the remaining Net Book Value of Rockport Unit 2 on a levelized basis through December 31, 2028.
3. Upon approval of revised Phase-In Rate Adjustment Rates in January 2023, this Rider shall also recover the non-current SO_2 allowance inventory over an amortization period ending December 31, 2028.

All customer bills subject to the provisions of this rider shall be adjusted by the ECR per billing kWh and kW~~kVA~~ as follows:

Tariff Class	¢/kWh	$/kW~~kVA~~
RS, RS-TOD, RS-TOD2, RS-OPES, RSD, RS-PEV and RS-CPP	x.xxxx	--
GS (up to 4,500 kWh)	x.xxxx	--
GS (over 4,500 kWh), LGS and LGS-TOD	x.xxxx	--
GS (over 10 kW), LGS and LGS - TOD	--	x.xxxx
GS-LM-TOD, GS-TOD2, GS Unmetered, GS-TOD, GS-PEV, ~~and~~ GS-CPP and LGS-LM-TOD	x.xxxx	--
IP and CS-IRP2	x.xxxx	x.xxxx
MS	x.xxxx	--
WSS	x.xxxx	--
IS	x.xxxx	--
EHG	x.xxxx	x.xxxx
OL	x.xxxx	--
SLS, ECLS, SLC, SLCM AND FW-SL	x.xxxx	--

ISSUED BY
STEVEN F. BAKER
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FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 48**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

OFF SYSTEM SALES MARGIN SHARING / PJM COST RIDER

This rider combines Off-System Sales Margin Sharing with PJM Costs (OSS / PJM Cost Rider). The OSS / PJM Cost Rider allows the Company to share wholesale margins related to Indiana retail electric service with customers while recovering costs associated with mandated participation in a regional transmission organization. All customer bills subject to the provisions of this rider shall be adjusted by the OSS / PJM Cost Rider adjustment factor per billing kWh and kW ~~or kVA~~ as follows:

Tariff Class	¢/kWh	$/kW ~~or $/kVA~~
RS, RS-TOD, RS-TOD2,RS-OPES, RSD, RS-PEV and RS-CPP	x.xxxx	--
GS (up to 4,500 kWh)	x.xxxx	--
GS (over 4,500 kWh), LGS and LGS-TOD	x.xxxx	--
GS (over 10 kW), LGS and LGS - TOD	--	x.xxxx
GS-LM-TOD, GS-TOD2, GS Unmetered, GS-TOD, GS-PEV, ~~and~~ GS-CPP and LGS-LM-TOD	x.xxxx	--
~~L.G.S.~~	~~x.xxxx~~	~~x.xxxx~~
IP and CS-IRP2	x.xxxx	x.xxxx
MS	x.xxxx	--
WSS	x.xxxx	--
IS	x.xxxx	--
EHG	x.xxxx	x.xxxx
OL	x.xxxx	--
SLS, ECLS, SLC, SLCM and FW-SL	x.xxxx	--

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EFFECTIVE FOR BILLS RENDERED BEGINNING ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

LIFE CYCLE MANAGEMENT RIDER (LCMR)

The Life Cycle Management Rider (LCMR) allows the Company to recover costs associated with the D.C. Cook Nuclear Plant so that it can continue to operate reliably through the plant's current operating license. All customer bills subject to the provisions of this rider shall be adjusted by the LCMR per kWh or kW ~~/ kVA~~ charges as follows:

Tariff Class	¢/kWh	$ per kW ~~/ kVA~~
RS, RS-TOD, RS-TOD2, RS-OPES, RSD, RS-PEV and RS-CPP	X.XXXX	--
GS (up to 4,500 kWh)	X.XXXX	--
GS (over 4,500 kWh), LGS and LGS-TOD	X.XXXX	--
GS (over 10 kW), LGS and LGS-TOD	--	X.XXXX
GS-LM-TOD, GS-TOD2, GS Unmetered, GS-TOD, GS-PEV, ~~and~~ GS-CPP and LGS-LM-TOD	X.XXXX	--
~~L.G.S.~~	~~X.XXXX~~	~~X.XXXX~~
IP and CS-IRP2	X.XXXX	X.XXXX
MS	X.XXXX	--
WSS	X.XXXX	--
IS	X.XXXX	--
EHG	X.XXXX	X.XXXX
OL	X.XXXX	--
SLS, ECLS, SLC, SLCM AND FW-SL	X.XXXX	--

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 50**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

RESOURCE ADEQUACY RIDER (RAR)

The Resource Adequacy Rider (RAR) allows the Company to recover costs associated with incremental changes in the Company's purchased power capacity costs. This rider also allows customers to benefit from sales of capacity related to Indiana retail service that may occur in the future. Upon the effective date of this tariff sheet and continuing through the first billing cycle of January 2023, this Rider shall also recover the non-fuel expenses incurred through December 7, 2022 associated with the AEG Unit Power Agreement for Rockport Unit 2.

All customer bills subject to the provisions of this rider shall be adjusted by the (RAR) per billing kWh and kW ~~/ kVA~~ charges as follows:

Tariff Class	¢/kWh	$/kW ~~or kVA~~
RS, RS-TOD, RS-TOD2 and RS-OPES, RSD, RS-PEV and RS-CPP	x.xxxx	--
GS (up to 4,500 kWh)	x.xxxx	--
GS (over 4,500 kWh), LGS and LGS-TOD	x.xxxx	--
GS (over 10 kW), LGS and LGS - TOD	--	x.xxxx
GS-LM-TOD, GS-TOD2, GS Unmetered, GS-TOD, GS-PEV, ~~and~~ GS-CPP and LGS-LM-TOD	x.xxxx	--
~~L.G.S.~~	~~x.xxxx~~	~~x.xxxx~~
IP and CS-IRP2	x.xxxx	x.xxxx
MS	x.xxxx	--
WSS	x.xxxx	--
IS	x.xxxx	--
EHG	x.xxxx	x.xxxx
OL	x.xxxx	--
SLS, ECLS, SLC, SLCM and FW-SL	x.xxxx	--

ISSUED BY
STEVEN F. BAKER
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FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

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I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 51

SOLAR POWER~~RENEWABLE PROJECTS~~ RIDER (SPR)

The Solar Power~~Renewable Projects~~ Rider (~~R~~SPR) surcharge allows the company to recover costs associated with investments in ~~renewable energy projects~~the St. Joseph Solar Project as approved by the Commission. All customer bills subject to the provisions of this rider shall be adjusted by the ~~R~~SPR per billing kWh and kW~~/kVA~~ as follows:

Tariff Class	¢/kWh	$ / kW ~~or kVA~~
RS, RS-TOD, RS-TOD2, RS-OPES, RS PEV, RSD and RS CPP	x.xxxx	--
GS (up to 4,500 kWh)	x.xxxx	--
GS (over 4,500 kWh), LGS and LGS-TOD	x.xxxx	--
GS (over 10 kW), LGS and LGS-TOD	--	x.xxxx
GS-LM-TOD, GS-TOD2, GS Unmetered, GS-TOD, GS-PEV, ~~and~~ GS-CPP and LGS-LM-TOD	x.xxxx	--
~~L.G.S.~~	~~x.xxxx~~	~~x.xxxx~~
IP and CS-IRP2	x.xxxx	x.xxxx
MS	x.xxxx	--
WSS	x.xxxx	--
IS	x.xxxx	--
EHG	x.xxxx	x.xxxx
OL	x.xxxx	--
SLS, ECLS, SLC, SLCM AND FW-SL	x.xxxx	--

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FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

I.U.R.C. NO. 19 **ORIGINAL SHEET NO. 52**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

PHASE-IN RATE ADJUSTMENT (PRA)

The Phase-In Rate Adjustment (PRA) allows the Company to phase-in base rates with the cost of providing service as approved by the Commission.

1. Upon the effective date of this tariff sheet, and continuing until a revised Plant in Service Credit is approved in January 2023, this Rider shall provide a Plant in Service Credit that reflects the difference between January 1, 2022 net plant and December 31, 2022 net plant.
2. Upon the effective date of this tariff sheet, and continuing through December 7, 2022, this Rider shall provide an Excluded Capacity Credit of $2,625,358 per month. This credit shall not apply to service rendered on or after December 8, 2022.
3. Upon the effective date of this tariff sheet, and continuing through December 7, 2022, this Rider shall provide a PRA Rockport Charge for costs and expenses associated with Rockport Unit 2 that are not tracked in other riders. This charge shall not apply to service rendered on or after December 8, 2022.
4. As part of the filing to establish a revised Plant in Service Credit to be effective in January 2023, that filing shall include and this Rider shall also provide a credit to remove the remaining Net Book Value of Rockport Unit 2 of $77,687,384 from base rates. This credit shall continue until new base rates are established which exclude the Net Book Value.

All customer bills subject to the provisions of this rider shall be adjusted by the PRA adjustment factor per billing kWh and kW~~/kVA~~ as follows.

Phase I Rates		
Tariff Class	¢/kWh	$/kW~~ or kVA~~
RS, RS-TOD, RS-TOD2, RS-OPES, RSD, RS-PEV and RS-CPP	~~(0.3753)~~ 0.0385	--
GS (up to 4,500 kWh)	~~(0.2513)~~ 0.1061	
GS (over 4,500 kWh), LGS and LGS-TOD	~~(0.0054)~~ 0.1525	--
GS (over 10 kW), LGS and LGS - TOD	--	~~(0.732)~~ (0.141)
GS-LM-TOD, GS-TOD2, GS Unmetered, GS-TOD, GS-PEV, ~~and~~ GS- CPP and LGS-LM-TOD	~~(0.2513)~~ 0.1061	--
~~L.G.S.~~	~~x.xxxx~~	~~x.xxxx~~
IP and CS-IRP2	~~(0.0047)~~ 0.1533	~~(0.599)~~ 0.032
MS	~~(0.2824)~~ 0.0953	
WSS	~~(0.1689)~~ 0.1287	
IS	~~(0.5326)~~ (0.0766)	--
EHG	~~(0.0054)~~ 0.1526	~~(0.577)~~ (0.153)
OL	~~(0.5538)~~ (0.1351)	--
SLS, ECLS, SLC, SLCM and FW-SL	~~(0.2547)~~ 0.0366	--

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

~~I.U.R.C. NO. 19~~ ~~ORIGINAL SHEET NO. 53~~
~~INDIANA MICHIGAN POWER COMPANY~~
~~STATE OF INDIANA~~

~~ADVANCED METERING INFRASTRUCTURE (AMI) RIDER~~

~~The Advanced Metering Infrastructure (AMI) Rider surcharge allows the company to recover costs associated with investments in AMI metering technology as approved by the Commission. All customer bills subject to the provisions of this rider shall be adjusted by the AMI Rider per billing kWh and kW as follows:~~

~~Tariff Class~~	~~¢/kWh~~	~~$/kW~~
~~RS, RS-TOD, RS-TOD2, RS-OPES, RSD, RS-PEV and RS-CPP~~	~~x.xxxx~~	~~--~~
~~GS (up to 4,500 kWh)~~	~~x.xxxx~~	~~--~~
~~GS (over 4,500 kWh) and LGS-TOD~~	~~x.xxxx~~	~~--~~
~~GS (over 10 kW) and LGS-TOD~~	~~--~~	~~x.xxx~~
~~GS-LM-TOD, GS-TOD2, GS Unmetered, GS-TOD, GS-PEV and GS-CPP~~	~~x.xxxx~~	~~--~~
~~IP and CS-IRP2~~	~~x.xxxx~~	~~x.xxx~~
~~MS~~	~~x.xxxx~~	~~--~~
~~WSS~~	~~x.xxxx~~	~~--~~
~~IS~~	~~x.xxxx~~	~~--~~
~~EHG~~	~~x.xxxx~~	~~x.xxx~~
~~OL~~	~~x.xxxx~~	~~--~~
~~SLS, ECLS, SLC, SLCM, and FW-SL~~	~~x.xxxx~~	~~--~~

~~ISSUED BY~~ ~~EFFECTIVE FOR ELECTRIC SERVICE RENDERED~~
~~TOBY L. THOMAS~~ ~~ON AND AFTER~~
~~PRESIDENT~~
~~FORT WAYNE, INDIANA~~ ~~ISSUED UNDER AUTHORITY OF THE~~
~~INDIANA UTILITY REGULATORY COMMISSION~~
~~DATED~~
~~IN CAUSE NO.~~

I.U.R.C. NO. 19
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 53~~54~~

TAX RIDER

The Tax Rider has two purposes:

(1) to credit customer rates for the remaining benefits associated with the unprotected EADFIT associated with the Tax Cuts and Jobs Act of 2017 and

(2) to implement ratemaking adjustments associated with an IRS PLR that requires I&M to make its proposed NOLC adjustment. ~~surcharge allows the company to refund remaining accumulated unprotected deferred federal income tax associated with the Tax Cuts and Jobs Act of 2017 through 2022. This rider will also be used to track and adjust future changes to federal corporate income tax above or below the amount of federal taxes in base rates as approved by the Commission.~~

All customer bills subject to the provisions of this rider shall be adjusted by the Tariff Class per billing kWh and kW as follows:

Tariff Class	¢/kWh	$/kW ~~or $/kVA~~
RS, RS-TOD, RS-TOD2, RS-OPES, RSD, RS-PEV and RS-CPP	x.xxxx	--
GS (up to 4,500 kWh)	x.xxxx	--
GS (over 4,500 kWh), LGS and LGS-TOD	x.xxxx	--
GS (over 10 kW), LGS and LGS-TOD	--	x.xxx
GS-LM-TOD, GS-TOD2, GS Unmetered, GS-TOD, GS-PEV, ~~and~~ GS-CPP and LGS-LM-TOD	x.xxxx	--
IP and CS-IRP2	x.xxxx	x.xxx
MS	x.xxxx	--
WSS	x.xxxx	--
IS	x.xxxx	--
EHG	x.xxxx	x.xxx
OL	x.xxxx	--
SLS, ECLS, SLC, SLCM, and FW-SL	x.xxxx	--

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON AN AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION DATED
IN CAUSE NO. 45576

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN RATE ADJUSTMENT; AND FOR APPROVAL OF RELATED RELIEF INCLUDING: (1) REVISED DEPRECIATION RATES; (2) ACCOUNTING RELIEF; (3) INCLUSION OF CAPITAL INVESTMENT; (4) RATE ADJUSTMENT MECHANISM PROPOSALS; (5) CUSTOMER PROGRAMS: (6) WAIVER OR DECLINATION OF JURISDICTION WITH RESPECT TO CERTAIN RULES; AND (7) NEW SCHEDULES OF RATES, RULES AND REGULATIONS.	)	**CAUSE NO. 45576**

MUNCIE STIPULATION AND SETTLEMENT AGREEMENT

Indiana Michigan Power Company ("I&M") and the City of Muncie, Indiana ("Muncie"), (collectively the "Settling Parties"), solely for purposes of compromise and settlement, stipulate and agree that the terms and conditions set forth below represent a fair, just and reasonable resolution of the matters set forth below, subject to their incorporation by the Indiana Utility Regulatory Commission ("IURC" or "Commission") into a final, non-appealable order ("Final Order") without modification or further condition that may be unacceptable to any Settling Party. If the Commission does not approve this Muncie Stipulation and Settlement Agreement ("Muncie Settlement Agreement"), in its entirety, the entire Muncie Settlement Agreement shall be null and void and deemed withdrawn, unless otherwise agreed to in writing by the Settling Parties.

I. TERMS AND CONDITIONS.

1. I&M commits to: promptly identify the requirements for, assist with, and process any of the City of Muncie necessary system impact studies, interconnection applications and

agreements, and other prerequisites consistent with I&M's rules and regulations, and Indiana law; to collaboratively work with Muncie's selected representatives as is reasonable and necessary; and to facilitate the interconnection of the solar generating facility to be located on the former General Motors brownfield site in southwest Muncie referred to in testimony as the "Chevy Plant". Muncie has provided I&M preliminary designs and an approximate size range for the solar project and I&M has correspondingly provided information regarding: the I&M interconnection application process; the potential need for an impact study depending on the final project details to be provided by Muncie; and has also advised Muncie of I&M's ongoing integrated resource plan stakeholder process. I&M will timely advise Muncie and its representatives of any required additional prerequisite information or requirements for interconnection and shall use commercially reasonable efforts to process all impact studies, interconnection agreements, or related matters to the Muncie solar project. As part of its commitments herein, I&M will designate a qualified, single point of contact person to work directly with Muncie to clearly identify all information needed by I&M, any required steps to help expedite and facilitate interconnection, and distribution system interconnection options for Muncie's proposed Chevy Plant solar energy generating facility.

2. I&M further commits within 30 days of the I&M base rate case (Cause No. 45576) Settlement Agreement being approved to locate and provide Muncie with contact information for a qualified AEPSC affiliate entity representative to: reasonably assist Muncie with introductions to appropriate PJM Interconnection representatives who can provide Muncie with guidance on where to locate the processes, procedures, and logistics of making wholesale power sales into and through the PJM wholesale electric power market. To the extent any City application to FERC for Qualifying Facility (QF) status meets all the criteria for being a QF under federal law and regulation, I&M agrees that it would not oppose the application. Additionally, should Muncie

determine that it is necessary for Muncie to file a petition with the IURC under Ind. Code § 8-1-8.5-2 or Ind. Code § 8-1-2.5-5 to sell the energy and capacity from the proposed solar generation facility at wholesale through PJM, I&M agrees to meet with Muncie in advance of such filing and to provide any I&M interconnection information reasonably necessary for the filing. I&M reserves its right to take any position regarding any such IURC filing.

3. I&M expects to issue a Request for Proposal (RFP) in connection with its 2021 IRP Preferred Resource Plan Portfolio. I&M agrees to discuss as part of the IRP stakeholder process an RFP structure that would allow local solar resources to submit bids.

4. Muncie agrees that nothing herein requires I&M to provide legal, regulatory, financial or business development advice to Muncie, or to take on the burden to pursue regulatory relief on behalf of Muncie.

5. The Settling Parties further agree that nothing in this Muncie Settlement Agreement shall have any rate impact or otherwise would affect any issues raised or presented in the multi-party Stipulation and Settlement Agreement filed in this Cause No. 45576, and the other parties take no position with respect to any of the issues addressed herein.

6. Muncie also agrees to join in and support the rate case Stipulation and Settlement Agreement in Cause No. 45576 which provides that all parties agree to waive cross examination and a stipulation to the admission of all other party witness prefiled testimonies and exhibits.

II. PRESENTATION OF THE SETTLEMENT AGREEMENT TO THE COMMISSION.

1. The Settling Parties herein shall support this Muncie Settlement Agreement before the Commission and request that the Commission expeditiously accept and approve the Muncie

Settlement Agreement. No other party filed any cross-answering testimony and have agreed to waive cross examination of the I&M and Muncie witnesses.

2. The Settling Parties agree to offer the respective party prefiled testimonies as evidence of and in support of the Settlement Agreement and will be offered into evidence without objection and the Settling Parties hereby waive cross-examination of each other's witnesses. The Settling Parties propose to submit this Muncie Settlement Agreement and evidence conditionally, and that, if the Commission fails to approve this Muncie Settlement Agreement in its entirety without any change or approves it with condition(s) unacceptable to any Settling Party, the Settlement and supporting evidence shall be withdrawn and the Commission will continue to hear this with the proceedings resuming at the point they were suspended by the filing of this Muncie Settlement Agreement.

3. A Commission Order approving this Muncie Settlement Agreement shall be effective immediately, and the agreements contained herein shall be unconditional, effective and binding on the Settling Parties as an Order of the Commission.

III. EFFECT AND USE OF MUNCIE SETTLEMENT AGREEMENT.

1. It is understood that this Muncie Settlement Agreement is reflective of a negotiated settlement and neither the making of this Muncie Settlement Agreement nor any of its provisions shall constitute an admission by either Settling Party in this or any other litigation or proceeding except to the extent necessary to implement and enforce its terms. It is also understood that each and every term of this Muncie Settlement Agreement is in consideration and support of each and every other term.

2. Neither the making of this Muncie Settlement Agreement (nor the execution of any of the other documents or pleadings required to effectuate the provisions of this Muncie Settlement Agreement), nor the provisions thereof, nor the entry by the Commission of a Final Order approving this Muncie Settlement Agreement, shall establish any principles or legal precedent applicable to Commission proceedings other than those resolved herein.

3. This Muncie Settlement Agreement shall not constitute and shall not be used as precedent by any person or entity in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce this Muncie Settlement Agreement.

4. This Muncie Settlement Agreement is solely the result of compromise in the settlement process and except as provided herein, is without prejudice to and shall not constitute a waiver of any position that either Settling Party may take with respect to any or all of the items resolved here and in any future regulatory or other proceedings.

5. The Settling Parties submit that evidence in support of this Muncie Settlement Agreement constitutes substantial evidence sufficient to support this Muncie Settlement Agreement and provides an adequate evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of this Muncie Settlement Agreement, as filed.

6. The communications and discussions during the negotiations and conferences and any materials produced and exchanged concerning this Muncie Settlement Agreement all relate to offers of settlement and shall be confidential, without prejudice to the position of either Settling Party, and are not to be used in any manner in connection with any other proceeding or otherwise.

7. The undersigned Settling Parties have represented and agreed that they are fully authorized to execute the Muncie Settlement Agreement on behalf of their respective clients, and their successor and assigns, which will be bound thereby.

8. The Settling Parties shall not appeal or seek rehearing, reconsideration or a stay of the Commission Order approving this Muncie Settlement Agreement in its entirety and without change or condition(s) acceptable to any Settling Party (or related orders to the extent such orders are specifically implementing the provisions of this Muncie Settlement Agreement).

9. The provisions of this Muncie Settlement Agreement shall be enforceable by any Settling Party to this agreement first before the Commission by filing a formally docketed case before the full Commission, and thereafter a complaint may be filed in any state court of competent jurisdiction as necessary.

10. This Muncie Settlement Agreement may be executed in two or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

ACCEPTED and AGREED as of the 16th day of November, 2021.

INDIANA MICHIGAN POWER COMPANY

Steven F. Baker
I&M President and Chief Operating Officer
Indiana Michigan Power Center
Fort Wayne, Indiana 46802

THE CITY OF MUNCIE, INDIANA

Mayor Dan Ridenour, City of Muncie