THIS FILING IS
Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No.

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company) Indiana Michigan Power Company	Year/Period of Report End of: 2023/ Q4

FERC FORM NO. 1 (REV. 02-04)

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

1. one million megawatt hours of total annual sales,
2. 100 megawatt hours of annual sales for resale,
3. 500 megawatt hours of annual power exchanges delivered, or
4. 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

a. Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

b. The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

c. Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

d. For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

   The CPA Certification Statement should:

   a. Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

   b. Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e. The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

   "In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

   Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

f. Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

g. Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

IV. When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

a. FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b. FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII. For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

X. Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

3. 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;
4. 'Person' means an individual or a corporation;
5. 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

7. 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

11. "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

a. 'To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

a. Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

GENERAL PENALTIES

The Commission may assess up to $1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1 REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER		
IDENTIFICATION		
01 Exact Legal Name of Respondent Indiana Michigan Power Company		02 Year/ Period of Report End of: 2023/ Q4
03 Previous Name and Date of Change (If name changed during year) /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 1 Riverside Plaza, Columbus, OH 43215-2373		
05 Name of Contact Person Jason M. Johnson		06 Title of Contact Person Accountant
07 Address of Contact Person (Street, City, State, Zip Code) 1 Riverside Plaza, Columbus, OH 43215-2373		
08 Telephone of Contact Person, Including Area Code 614-716-1000	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/09/2024
Annual Corporate Officer Certification		
The undersigned officer certifies that: I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.		
01 Name Jeffrey W. Hoersdig 02 Title Assistant Controller	03 Signature Jeffrey W. Hoersdig	04 Date Signed (Mo, Da, Yr) 04/09/2024
Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.		

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Jeffrey W. Hoersdig

1 Riverside Plaza Columbus, Ohio 43215-2373

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Indiana - February 21, 1925

State of Incorporation:

Date of Incorporation:

Incorporated Under Special Law:

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric - IndianaElectric - Michigan

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) ☐ Yes

(2) ☑ No

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

American Electric Power Company, Inc. - Ownership of 100% of Respondent's Common Stock

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Price River Coal Company, Inc.	Coal Company - Inactive	100%	
2	Blackhawk Coal Company, Inc.	Coal Company - Inactive	100%	

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	[(a)] Footnote				

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Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: OfficerTitle

Schedule Page: 104 Line No.: 1 Column: a

The following table provides summary information concerning compensation earned by our Chief Executive Officer, our two Chief Financial Officers during 2023, the three other most highly compensated executive officers and one additional former executive officer whose compensation would have been among the three most highly compensated executive officers other than the CEO and CFOs if he had been an executive officer at year end. We refer collectively to this group as the named executive officers (NEOs).

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)(2)	Stock Awards ($)(3)	Non-Equity Incentive Plan Compensation ($)(4)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(5)	All Other Compensation ($)(6)	Total ($)
Julia A. Sloat								
Chair of the Board, President and Chief Executive Officer	2023	1,200,000	—	8,321,524	787,503	210,263	114,555	10,633,745
Charles E. Zebula								
Executive Vice President and Chief Financial Officer	2023	639,625	—	2,852,248	240,500	181,438	73,170	3,986,981
David M. Feinberg								
Executive Vice President, General Counsel and Secretary	2023	746,000	— —	1,560,286	263,500	151,597	109,767	2,831,150
Christian T. Beam								
Executive Vice President - Energy Services	2023	585,000	—	1,248,229	220,500	123,014	170,900	2,347,643
Peggy I. Simmons								
Executive Vice President - Utilities	2023	585,000	—	1,248,229	220,500	86,652	87,482	2,227,863
Nicholas K. Akins								
Former Executive Chair of the Board	2023	862,500	—	2,000,000	696,149	729,068	359,384	4,647,101
Ann P. Kelly								
Former Executive Vice President and Chief Financial Officer	2023	525,000	250,000	2,042,588	—	—	550,866	3,368,454

(1) Amounts in the salary column are composed of executive salaries earned for the year shown, which include 260 days of pay for 2023, which is the number of workdays and holidays in a standard year.

(2) The amount in the bonus column for Ms. Kelly is a negotiated hire bonus paid in 2023 following her November 2022 hire into the EVP and CFO position.

(3) The amounts reported in this column reflect the aggregate grant date fair value calculated in accordance with FASB ASC Topic 718 of the performance shares, restricted stock units (RSUs) and unrestricted shares granted under our Long-Term Incentive Plan. See Note 15 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2023 for a discussion of the relevant assumptions used in calculating these amounts. The number of shares realized and the value of the performance shares, if any, will depend on the Company's performance during a 3-year performance period. The potential payout can range from 0 percent to 200 percent of the target number of performance shares, plus any dividend equivalents. The value of the performance shares will be based on three measures: a Board approved cumulative operating earnings per share measure (Cumulative EPS 50%), a total shareholder return relative to peer companies (Relative TSR 40%) and a carbon free generation capacity additions (Carbon Free Additions 10%). The grant date fair value of the 2023, 2022 and 2021 performance shares that are based on Cumulative EPS was computed in accordance with FASB ASC Topic 718 and was measured based on the closing price of AEP's common stock on the grant date. The maximum amount payable for the 2023 performance shares
that are based on Cumulative EPS measured on the grant date is $3,000,000 for Ms. Sloat, $487,500 for Mr. Zebula, 562,500 for Mr. Feinberg, $450,000 for Mr. Beam, $450,000 for Ms. Simmons, $0 for Mr. Akins, and $652,495 for Ms. Kelly. The maximum amount payable for the 2023 performance shares that are based on Carbon Free Capacity additions is $600,000 for Ms. Sloat, $97,500 for Mr. Zebula, $112,500 for Mr. Feinberg, $90,000 for Mr. Beam, $90,000 for Ms. Simmons, $0 Mr. Akins, and $130,499 for Ms. Kelly. The grant date fair value of the 2023 performance shares that are based on Relative TSR is calculated using a Monte-Carlo model as of the date of grant, in accordance with FASB ASC Topic 718. Because the performance shares that are based on Relative TSR are subject to market conditions as defined under FASB ASC Topic 718, they did not have a maximum value on the grant date that differed from the grant date fair values presented in the table. Instead, the maximum value is factored into the calculation of the grant date fair value. The values realized from the 2021 performance shares are included in the Option Exercises and Stock Vested for 2023 table.

(4) The amounts shown in this column reflect annual incentive compensation paid for the year shown.

(5) The amounts shown in this column are attributable to the increase in the actuarial values of each of the named executive officer's combined benefits under AEP's qualified and non-qualified defined benefit pension plans determined using interest rate and mortality assumptions consistent with those used in the Company's financial statements. See the Pension Benefits for 2023 table and related footnotes for additional information. See Note 8 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2023 for a discussion of the relevant assumptions. None of the named executive officers received preferential or above-market earnings on deferred compensation.

(6) Amounts shown in the All Other Compensation column for 2023 include: (a) Company matching contributions to the Company's Retirement Savings Plan, (b) Company matching contributions to the Company's Supplemental Retirement Savings Plan, (c) relocation, (d) perquisites, and (e) vacation payout. The 2023 values for these items are listed in the following table:

Type	Julia A. Sloat	Charles E. Zebula	David M. Feinberg	Christian T. Beam	Peggy I. Simmons	Nicholas K. Akins	Ann P. Kelly
Retirement Savings Plan Match	$ 14,85	$ 14,85	$ 14,85	$ 14,85	$ 14,85	$ 14,85	$ 14,85
Supplemental Retirement Savings Plan Match	84,297	45,565	54,917	30,349	22,275	188,169	7,043
Relocation	—	—	—	111,156	35,812	—	238,006
Perquisites	15,308	12,755	40,000	14,545	14,545	20,632	264,717
Vacation Payout	—	—	—	—	—	135,733	26,250
Total	**$ 114,45**	**$ 73,17**	**$ 109,76**	**$ 170,90**	**$ 87,48**	**$ 359,38**	**$ 550,86**

Perquisites provided in 2023 included: financial counseling and tax preparation services and, for Ms. Sloat and Mr. Akins, director's group travel accident insurance premium. Executive officers may also have the occasional personal use of event tickets when such tickets are not being used for business purposes, however, there is no associated incremental cost. From time-to-time executive officers may receive customary gifts from third parties that sponsor events (subject to our policies on conflicts of interest).

Provided Ms. Kelly complies with the terms of her Executive Severance, Noncompetition and Release of All Claims Agreement, she will receive $1,260,000 in cash severance benefits and up to $15,650 in outplacement services in 2024 in connection with her 2023 separation from AEP employment.

Ms. Sloat and Mr. Akins prior to his retirement were parties to Aircraft Time Sharing Agreements with the Company that allowed her or him to use our corporate aircraft for personal use for a limited number of hours each year. As required under these Aircraft Time Sharing Agreement Ms. Sloat and Mr. Akins to reimbursed the Company for the cost of her or his personal use of corporate aircraft in accordance with limits set forth in Federal Aviation Administration regulations. Ms. Sloat and Mr. Akins reimbursed the Company all incremental costs incurred in connection with personal flights under their Aircraft Timesharing Agreement including fuel, oil, hangar costs, crew travel expenses, catering, landing fees and other incremental airport fees. Accordingly, no value is shown for these amounts in the Summary Compensation Table. If the aircraft flew empty to pick up or after dropping off Ms. Sloat or Mr. Akins at a destination on a personal flight, the cost of the empty flight was included in the incremental cost for which Ms. Sloat or Mr. Akins was required to reimburse the Company.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	Julia A. Sloat, Chair of the Board and Chief Executive Officer	Columbus, Ohio	true	true
2	Charles E.Zebula Vice President and Chief Financial Officer	Columbus, Ohio	true	false
3	Steven F.Baker - Chief Operating Officer and President	Fort Wayne, Indiana	true	false
4	Katherine K.Davis - Vice President - External Affairs and Customer Experience	Fort Wayne, Indiana	false	false
5	Nicholas M.Elkins - Director Customer and Business Services	Fort Wayne, Indiana	false	false
6	David S. Isaacson - Vice President - Distribution Region Operations	Fort Wayne, Indiana	false	false
7	Andrew J. Williamson - Director Regulatory Services	Fort Wayne, Indiana	false	false
8	Ann P. Kelly, Vice President and Chief Financial Officer	Columbus, Ohio	true	false
9	Peggy I.Simmons,Vice President	Columbus, Ohio	true	false
10	Toby L. Thomas,Vice President	Fort Wayne, Indiana	false	false

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	☑ Yes ☐ No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	PJM Interconnection LLC - Attachment H-14	ER17-405

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	☑ Yes ☐ No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website.

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20231218-5307	12/18/2023	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14
2	20231031-5276	10/31/2023	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14
3	20230525-5176	05/25/2023	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

INFORMATION ON FORMULA RATES - Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
1	204-207	Electric Plant in Service	g	49
2	214	Electric Plant Held for Future Use	d	46
3	216	Construction Work in Progress	b	1
4	219	Accumulated Depreciation	b	21
5	310-311	Sales for Resale	k	1
6	320	Electric Operations & Maintenance Expense	b	5
7	320	Electric Operations & Maintenance Expense	b	25
8	320	Electric Operations & Maintenance Expense	b	31
9	321	Electric Operations & Maintenance Expense	b	93
10	323	Electric Operations & Maintenance Expense	b	185
11	336	Depreciation Expense	b	7
12	354	Distribution of Wages and Salaries	b	28

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

Date Acquired Or Extended	Community	Period of Franchise & Termination	Consideration
8/22/2023	Texas Township, Kalamazoo County, MI	Nine (9) years expiring August 22, 2032	None

None

None

None

None

$500M Indiana Michigan power company Senior Unsecured Notes , Series P(state authority: cause No.45817, FERC authority: N/A, Issued: 3/23/2023, Maturity: 4/1/2053)

$2,921,022 Letter of Credit issued by American Electric Power Company, Inc. on behalf of Indiana Michigan Power Company to benefit Nat'l Institute of Stds & Tech

$69.09M Indiana Michigan power company Nuclear fuel Lease(state authority: cause No.45806 Issued: 11/03/2023, Maturity: 05/13/2028)

None

1 Cook Nuclear Plant Maintenance employees represented by IBEW #1392 were provided with a 3.5% wage increase effective April 1, 2023.

13 Cook Nuclear Plant Stores employees represented by IBEW #1392 were provided with a 3.5% wage increase effective April 1, 2023.

52 Cook Nuclear Plant RPEC employees represented by IBEW #1392 were provided with a 3.5% wage increase effective April 1, 2023.

68 Cook Nuclear Plant NON Licensed Operators employees represented by IBEW #1392 were provided with a 3.5% wage increase effective April 1, 2023.

62 River Transportation employees represented by USW # 14811 were provided with a 3.5% wage increase effective April 1, 2023.

17 Cook Nuclear Planners employees represented by IBEW #1392 were provided with a Exempt salary plan -wages effective April 1, 2023.

5 Cook Nuclear Plant QC/NDE Techs represented by IBEW #1392 were provided with a 3.5% wage increase effective May 19, 2023

94 Fort Wayne employees represented by IBEW #1392 were provided with a 2.5% wage increase ineffective Nov 1, 2023

142 Michiana & MHG employees represented by IBEW #1392 were provided with a 2.5% wage increase effective on November 1,2023

79 Munice employees represented by IBEW #1392 were provided with a 2.5% wage increase effective Nov 1,2023

3 Southern Maintenance Group represented by IBEW #1392 were provided with a 2.5% wage increase effective Nov 1, 2023

24 Trans Line employees represented by IBEW #1392 were provided with a 2.5% wage increase effective on November 1,2023

Please refer to the Notes to Financial Statements Pages 122-123

None

11. (Reserved)

Julia A Sloat,elected Chairman of the Board and Chief Executive Officer 1/1/2023.

ana M Koenig ,elected as Assistant Vice President-TAX effective on 04/11/2023.

ate Sturgess, elected as Chief Accounting Officer and Controller effective on 05/09/2023.

oseph M. Buonaiuto, resigned as Chief Accounting Officer and Controller effective on 05/08/2023.

imothy C. Kerns, resigned as Vice President - Generation Assets effective on 04/03/2023.

Peggy I Simmons, elected as Vice President effective on 08/18/2023.

Christian T Beam, elected as Vice President effective on 08/18/2023.

Daniel E Mueller elected as Assistant Vice President-TAX effective on 09/28/2023 and resigned as Assistant Vice President-TAX effective on 8/18/2023

Chodak, III Paul, resigned Vice President effective on 08/18/2023.

Eric J James, resigned as Vice President effective on 08/18/2023.

Scott N Smith, resigned as Vice President effective on 07/14/2023.

Thomas D Presthus, resigned as Vice President effective on 08/18/2023.

Mark J Leskowitz, resigned as Vice President effective on 08/18/2023.

Scott P Moore, resigned as Vice President effective on 08/18/2023.

Therace M Risch, resigned as Vice President effective on 08/18/2023.

Charles E Zebula, resigned as Vice President effective on 08/18/2023.

Toby L Thomas, resigned as Vice President effective on 08/18/2023 and as director effective on 07/26/2023

Phillip R Ulrich, resigned as Vice President effective on 08/18/2023.

Ann P Kelly, resigned as Chief Financial Officer, Vice President and Director effective on 09/29/2023.

Charles E Zebula elected as Director, Chief Financial Officer and Vice President effective on 10/03/2023

Proprietary capital ratio exceeds 30%

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200	11,377,231,808	11,026,604,026
3	Construction Work in Progress (107)	200	299,779,244	256,648,504
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		11,677,011,052	11,283,252,530
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	4,336,886,963	4,076,922,613
6	Net Utility Plant (Enter Total of line 4 less 5)		7,340,124,089	7,206,329,917
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	83,395,796	(38,893)
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)		2,558,943	1,645,219
10	Spent Nuclear Fuel (120.4)		580,843,929	629,554,317
11	Nuclear Fuel Under Capital Leases (120.6)		153,808,147	179,143,988
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202	582,317,204	629,431,130
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		238,289,611	180,873,501
14	Net Utility Plant (Enter Total of lines 6 and 13)		7,578,413,700	7,387,203,418
15	Utility Plant Adjustments (116)		(1,234,593)	(1,521,080)
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		683,974,696	670,402,649
19	(Less) Accum. Prov. for Depr. and Amort. (122)		595,584,094	577,465,961
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		22,907,857
23	Noncurrent Portion of Allowances	228	7,271,212	25,258,945
24	Other Investments (124)		11,792,273	12,408,146
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		3,860,213,704	3,341,237,453
29	Special Funds (Non Major Only) (129)		180,519,109	157,046,464
30	Long-Term Portion of Derivative Assets (175)		11,818,600	215,221
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		4,160,005,500	3,652,010,775
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		2,105,763	4,170,737
36	Special Deposits (132-134)		11,367,227	1,369,186
37	Working Fund (135)			
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		68,798,394	100,302,527
41	Other Accounts Receivable (143)		8,183,752	4,692,021
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		4,786	2,568
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		61,896,424	100,641,806
45	Fuel Stock (151)	227	84,069,956	44,879,566
46	Fuel Stock Expenses Undistributed (152)	227	3,988,855	1,646,495
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	206,412,591	186,279,221
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227	1,559,255	1,667,521

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	7,539,887	25,388,469
53	(Less) Noncurrent Portion of Allowances	228	7,271,212	25,258,945
54	Stores Expense Undistributed (163)	227		1
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		20,964,797	12,484,353
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)		140,982	355,807
61	Accrued Utility Revenues (173)		241,058	557,253
62	Miscellaneous Current and Accrued Assets (174)		21,084,973	24,043,675
63	Derivative Instrument Assets (175)		39,610,905	15,383,659
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		11,818,600	215,221
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		518,870,222	498,385,563
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		22,281,512	18,575,692
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	664,714,880	696,583,826
73	Prelim. Survey and Investigation Charges (Electric) (183)		11,799,921	4,914,241
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	99,346,760	78,311,371
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		11,793,731	12,874,071
82	Accumulated Deferred Income Taxes (190)	234	1,014,014,269	933,493,719
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		1,823,951,073	1,744,752,921
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		14,080,005,902	13,280,831,597

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Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250	56,583,866	56,583,866
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)		4,234,635	4,234,635
7	Other Paid-In Capital (208-211)	253	993,410,869	984,636,599
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b	127	127
11	Retained Earnings (215, 215.1, 216)	118	2,088,734,015	1,965,690,158
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	(2,086,935)	(2,416,145)
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(588,506)	(287,989)
16	Total Proprietary Capital (lines 2 through 15)		3,140,287,817	3,008,440,997
17	**LONG-TERM DEBT**			
18	Bonds (221)	256		
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	3,368,102,458	3,105,662,741
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		9,718,152	10,119,645
24	Total Long-Term Debt (lines 18 through 23)		3,358,384,306	3,095,543,096
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		140,206,676	170,107,704
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		781,940	298,465
29	Accumulated Provision for Pensions and Benefits (228.3)		7,358,193	8,369,172
30	Accumulated Miscellaneous Operating Provisions (228.4)		851,241	412,141
31	Accumulated Provision for Rate Refunds (229)		13,931,002	11,810,518
32	Long-Term Portion of Derivative Instrument Liabilities			15,970
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		2,105,922,479	2,028,056,023
35	Total Other Noncurrent Liabilities (lines 26 through 34)		2,269,051,531	2,219,069,993
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)			
38	Accounts Payable (232)		225,775,604	173,426,216
39	Notes Payable to Associated Companies (233)		63,309,819	249,940,964
40	Accounts Payable to Associated Companies (234)		107,351,786	121,494,974
41	Customer Deposits (235)		72,152,655	48,606,762
42	Taxes Accrued (236)	262	104,732,995	102,988,689
43	Interest Accrued (237)		41,295,071	36,865,840
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		7,127,317	7,068,953
48	Miscellaneous Current and Accrued Liabilities (242)		65,147,867	81,039,240
49	Obligations Under Capital Leases-Current (243)		99,593,043	107,995,874

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
50	Derivative Instrument Liabilities (244)		1,996,901	(31,881)
51	(Less) Long-Term Portion of Derivative Instrument Liabilities			15,970
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		788,483,058	929,379,661
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)			
57	Accumulated Deferred Investment Tax Credits (255)	266	15,772,724	17,350,699
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	28,739,109	25,439,687
60	Other Regulatory Liabilities (254)	278	2,295,381,583	1,894,919,119
61	Unamortized Gain on Reacquired Debt (257)			1,284
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	11,939,902	14,753,180
63	Accum. Deferred Income Taxes-Other Property (282)		1,166,950,482	1,162,093,451
64	Accum. Deferred Income Taxes-Other (283)		1,005,015,390	913,840,427
65	Total Deferred Credits (lines 56 through 64)		4,523,799,190	4,028,397,847
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		14,080,005,902	13,280,831,594
	Page 112-113			

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

6. Do not report fourth quarter data in columns (e) and (f)
7. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
8. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	2,305,195,850	2,683,980,655			2,305,195,850	2,683,980,655				
3	Operating Expenses											
4	Operation Expenses (401)	320	1,007,731,110	1,480,052,301			1,007,731,110	1,480,052,301				
5	Maintenance Expenses (402)	320	232,937,034	226,936,639			232,937,034	226,936,639				
6	Depreciation Expense (403)	336	406,335,551	398,405,567			406,335,551	398,405,567				
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	2,052,740	4,284,998			2,052,740	4,284,998				
8	Amort. & Depl. of Utility Plant (404-405)	336	45,929,089	61,848,393			45,929,089	61,848,393				
9	Amort. of Utility Plant Acq. Adj. (406)	336										
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)											
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)			(449,814)				(449,814)				
13	(Less) Regulatory Credits (407.4)		(5,660,713)	8,137,422			(5,660,713)	8,137,422				
14	Taxes Other Than Income Taxes (408.1)	262	80,452,744	94,533,065			80,452,744	94,533,065				
15	Income Taxes - Federal (409.1)	262	100,281,326	44,547,867			100,281,326	44,547,867				
16	Income Taxes - Other (409.1)	262	21,938,242	10,483,396			21,938,242	10,483,396				

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
17	Provision for Deferred Income Taxes (410.1)	234, 272	349,865,531	462,278,975			349,865,531	462,278,975				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	411,668,406	509,576,487			411,668,406	509,576,487				
19	Investment Tax Credit Adj. - Net (411.4)	266	(1,577,975)	(5,033,642)			(1,577,975)	(5,033,642)				
20	(Less) Gains from Disp. of Utility Plant (411.6)		615,873	631,371			615,873	631,371				
21	Losses from Disp. of Utility Plant (411.7)		209,501				209,501					
22	(Less) Gains from Disposition of Allowances (411.8)		58	4,299,350			58	4,299,350				
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)		2,256,443	2,435,359			2,256,443	2,435,359				
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,841,787,712	2,257,678,475			1,841,787,712	2,257,678,475				
27	Net Util Oper Inc (Enter Tot line 2 less 25)		463,408,138	426,302,180			463,408,138	426,302,180				
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)											
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)											
33	Revenues From Nonutility Operations (417)		194,622,278	117,131,577								
34	(Less) Expenses of Nonutility Operations (417.1)		185,175,348	79,594,358								
35	Nonoperating Rental Income (418)		553,976	341,431								
36	Equity in Earnings of Subsidiary Companies (418.1)	119	329,210	287,187								
37	Interest and Dividend Income (419)		2,577,052	658,051								
38	Allowance for Other Funds Used During Construction (419.1)		10,857,387	9,770,373								
39	Miscellaneous Nonoperating Income (421)		472,732	(1,524,240)								
40	Gain on Disposition of Property (421.1)		17,780	177,798								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		24,255,067	47,247,819								
42	Other Income Deductions											

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
43	Loss on Disposition of Property (421.2)		1,842	765,742								
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		993,378	12,282,743								
46	Life Insurance (426.2)											
47	Penalties (426.3)		25,763	2,334								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		778,192	1,450,863								
49	Other Deductions (426.5)		17,762,596	10,338,882								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		19,561,771	24,840,565								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	3,668,807	2,575,617								
53	Income Taxes-Federal (409.2)	262	(7,151,378)	(776,181)								
54	Income Taxes-Other (409.2)	262	(997,536)	278,704								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	16,511,805	13,616,289								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	8,943,666	11,873,866								
57	Investment Tax Credit Adj.-Net (411.5)											
58	(Less) Investment Tax Credits (420)											
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		3,088,032	3,820,563								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		1,605,264	18,586,691								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		130,890,015	116,690,752								
63	Amort. of Debt Disc. and Expense (428)		2,066,036	2,130,308								
64	Amortization of Loss on Reaquired Debt (428.1)		1,080,340	1,318,003								
65	(Less) Amort. of Premium on Debt-Credit (429)											
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		1,284	1,712								
67	Interest on Debt to Assoc. Companies (430)		3,195,053	2,893,111								
68	Other Interest Expense (431)		(422,845)	2,883,904								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		7,666,980	5,746,073								

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
70	Net Interest Charges (Total of lines 62 thru 69)		129,140,335	120,168,294								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		335,873,067	324,720,577								
72	Extraordinary Items											
73	Extraordinary Income (434)											
74	(Less) Extraordinary Deductions (435)											
75	Net Extraordinary Items (Total of line 73 less line 74)											
76	Income Taxes-Federal and Other (409.3)	262	0									
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		335,873,067	324,720,577								
Page 114-117												

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
4. State the purpose and amount for each reservation or appropriation of retained earnings.
5. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		1,960,690,274	1,746,436,904
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		335,543,857	324,433,390
17	Appropriations of Retained Earnings (Acct. 436)			
17.1	Reclassification of Appropriated Retained Earnings-Amort Reserve Federal		(131,279)	(180,020)
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		(131,279)	(180,020)
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	Dividends Declared-Common Stock		(212,500,000)	(110,000,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(212,500,000)	(110,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,083,602,852	1,960,690,274
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		5,131,163	4,999,884
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		5,131,163	4,999,884
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,088,734,015	1,965,690,158
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		(2,416,145)	(2,703,332)
50	Equity in Earnings for Year (Credit) (Account 418.1)		329,210	287,187
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)		(2,086,935)	(2,416,145)

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Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

STATEMENT OF CASH FLOWS

1. Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	335,873,067	324,720,577
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	454,317,381	464,538,958
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Regulatory Debits & Credits	5,660,713	(8,587,236)
5.2	Amortization of Nuclear Fuel	103,085,460	86,277,041
5.3	Accretion of Asset Retirement Obligation	2,256,443	2,435,359
8	Deferred Income Taxes (Net)	(54,234,737)	(45,555,089)
9	Investment Tax Credit Adjustment (Net)	(1,577,975)	(5,033,642)
10	Net (Increase) Decrease in Receivables	70,877,672	(81,880,582)
11	Net (Increase) Decrease in Inventory	(61,557,853)	(2,800,561)
12	Net (Increase) Decrease in Allowances Inventory	2,764,456	212,945
13	Net Increase (Decrease) in Payables and Accrued Expenses	28,702,804	45,782,938
14	Net (Increase) Decrease in Other Regulatory Assets	24,521,227	(51,380,477)
15	Net Increase (Decrease) in Other Regulatory Liabilities	(52,439,268)	(20,028,794)
16	(Less) Allowance for Other Funds Used During Construction	10,857,387	9,770,373
17	(Less) Undistributed Earnings from Subsidiary Companies	329,210	287,187
18	Other (provide details in footnote):		
18.1	Other (provide details in footnote):	[(a)](67,308,354)	(138,407,869)
18.2	Mark-to-Market of Risk Management Contracts	(22,198,465)	(17,103,425)
18.3	Over/Under Recovered Fuel,Net	55,947,745	(42,017,658)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	813,503,719	501,114,925
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(567,288,538)	(569,260,339)
27	Gross Additions to Nuclear Fuel	(129,871,313)	(102,715,455)
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	(272,640)	(311,352)
30	(Less) Allowance for Other Funds Used During Construction	(10,857,387)	(9,770,373)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
31.2	Acquired Assets	(1,274,829)	(12,647,866)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(687,849,933)	(675,164,640)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	[(b)]1,972,268	17,763,935
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)	(2,845,119,721)	(2,765,375,937)
45	Proceeds from Sales of Investment Securities (a)	2,787,538,306	2,713,633,868
46	Loans Made or Purchased		

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Sale of Barges		
53.2	Other (provide details in footnote):	[(c)]5,423,627	5,183,404
53.3	(increase) Decrease in Other Special Deposits	(925,231)	10,250,728
53.4	Note Receivable from Associated Companies		
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(738,960,684)	(693,708,643)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	500,000,000	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Capital Contributions from Parent	8,774,270	7,974,796
64.2	Long Term Issuance Costs	(5,157,840)	(35,142)
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Proceeds from Acquired Assets	826,096	459,856
67.2	Notes Payable to Associated Companies		156,609,669
67.3	Proceeds on Nuclear Fuel Leaseback	70,440,000	142,700,000
70	Cash Provided by Outside Sources (Total 61 thru 69)	574,882,526	307,709,179
72	Payments for Retirement of:		
73	Long-term Debt (b)	(252,359,390)	(2,222,323)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):		
76.2	Notes Payable to Associated Companies - Retired	(186,631,145)	
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(212,500,000)	(110,000,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	(76,608,009)	195,486,856
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	(2,064,974)	2,893,138
88	Cash and Cash Equivalents at Beginning of Period	4,170,737	1,277,599
90	Cash and Cash Equivalents at End of Period	2,105,763	4,170,737

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FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

	2023 Cash Flow Incr / (Decr)	2022 Cash Flow Incr / (Decr)
Utility Plant, Net	$ (141,621,280)	$ (178,608,788)
Property and Investments, Net	32,048,324	3,292,403
Margin Deposits	(9,072,810)	7,253,715
Prepayments	(30,273,435)	(12,299,418)
Accrued Utility Revenues, Net	316,195	(557,253)
Miscellaneous Current and Accr Assets	5,057,953	2,054,876
Unamortized Debt Expense	1,297,020	1,538,724
Other Deferred Debits, Net	(30,266,632)	(14,369,170)
Proprietary Capital, Net		
Other Comprehensive Income, Net	(353,078)	1,602,302
Unamortized Discount/Premium on Long-Term Debt	556,493	585,729
Accumulated Provisions - Misc	3,049,636	8,188,758
Current and Accrued Liabilities, Net	7,567,257	(33,318,900)
Other Deferred Credits, Net	94,386,003	76,229,153
Total	**$ (67,308,354)**	**$ (138,407,869)**

(b) Concept: ProceedsFromDisposalOfNoncurrentAssets

	2023 Cash Flow Incr / (Decr)	2022 Cash Flow Incr / (Decr)
Sale of transformers between various operating companies	$ 853,534	$ 2,389,877
Sale of meters between various operating companies	338,301	512,125
Transco Transfer of Assets	111,481	1,513,614
Land Sale Dumont / Lakeville Site, Dumont UHV Test Facility		147,595
Land Sale of Buchanan Nuclear Headquarters 19.19+/- acres in Buchanan, MI	196,670	
Sale of Mobile Station Assets from I&M-D to OPCo-D Mobile Station	472,282	
Sale of two 176 foot 345kV DC Tangent Emergency Restoration Structures from I&M-T Sorenson 345/138/132.2 Station to ETT Edith Clarke-Riley 345kV Line.		308,564
Sale of IP Rotor		887,160
Sales of Marine Vessel		12,005,000
Total	**$ 1,972,268**	**$ 17,763,935**

(c) Concept: OtherAdjustmentsToCashFlowsFromInvestmentActivities

	2023 Cash Flow Incr / (Decr)	2022 Cash Flow Incr / (Decr)
DOE Reimbursemnt	$ 2,572,539	$ —
CIAC Proceeds	2,851,088	1,536,317
Insurance Receivable		3,156,980
DOE Proceeds		196,086
Other investing		294,021
Total	**$ 5,423,627**	**$ 5,183,404**

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

INDEX OF NOTES TO FINANCIAL STATEMENTS

GLOSSARY OF TERMS FOR NOTES

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority-owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated VIE of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KGPCo, KPCo, OPCo and WPCo.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Wind Holdings, LLC	Acquired in April 2019 as Sempra Renewables LLC, develops, owns and operates, or holds interests in, wind generation facilities in the United States.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a wholly-owned subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns the State Transcos.
AFUDC	Allowance for Equity Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary. APCo engages in the generation, transmission and distribution of electric power to retail customers in the southwestern portion of Virginia and southern West Virginia.
ARO	Asset Retirement Obligations.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,296 MW nuclear plant owned by I&M.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel XIII, DCC Fuel XIV, DCC Fuel XV, DCC Fuel XVI, DCC Fuel XVII and DCC Fuel XVIII, DCC Fuel XIX consolidated VIEs formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DOE	U. S. Department of Energy.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated VIE of AEP.
Excess ADIT	Excess accumulated deferred income taxes.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary. I&M engages in the generation, transmission and distribution of electric power to retail customers in northern and eastern Indiana and southwestern Michigan.
IRA	On August 16, 2022 President Biden signed into law legislation commonly referred to as the "Inflation Reduction Act" (IRA).
IRS	Internal Revenue Service.
ITC	Investment Tax Credit.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary. KGPCo provides electric service to retail customers in Kingsport, Tennessee and eight neighboring communities in northeastern Tennessee.

Term	Meaning
KPCo	Kentucky Power Company, an AEP electric utility subsidiary. KPCo engages in the generation, transmission and distribution of electric power to retail customers in eastern Kentucky.
KWh	Kilowatt-hour.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
NO_x	Nitrogen oxide.
NRC	Nuclear Regulatory Commission.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary. OPCo engages in the transmission and distribution of electric power to retail customers in Ohio.
OPEB	Other Postretirement Benefits.
OTC	Over-the-counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PCA	Power Coordination Agreement among APCo, I&M, KPCo and WPCo.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PPA	Purchase Power and Sale Agreement.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary. PSO engages in the generation, transmission and distribution of electric power to retail customers in eastern and southwestern Oklahoma.
PTC	Production Tax Credit.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, jointly-owned by AEGCo and I&M, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana.
ROE	Return on Equity.
RPM	Reliability Pricing Model.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sempra Renewables LLC	Sempra Renewables LLC, acquired in April 2019 (subsequently renamed as AEP Wind Holdings LLC), consists of 724 MWs of wind generation and battery assets in the United States.
SNF	Spent Nuclear Fuel.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary. SWEPCo engages in the transmission and distribution of electric power to retail customers in northeastern and panhandle of Texas, northwestern Louisiana and western Arkansas.
TA	Transmission Agreement, effective November 2010, among APCo, I&M, KGPCo, KPCo, OPCo and WPCo with AEPSC as agent.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary. WPCo provides electric service to retail customers in northern West Virginia.

1.
ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
ORGANIZATION

As a public utility, I&M engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 613,000 retail customers in its service territory in northern and eastern Indiana and southwestern Michigan. I&M sells power at wholesale to municipalities and electric cooperatives. I&M's River Transportation Division provides barging services to affiliates and nonaffiliated companies. The revenues from barging represent the majority of other revenues.

To minimize the credit requirements and operating constraints when operating within PJM, participating AEP companies, including I&M, agreed to a netting of certain payment obligations incurred by the participating AEP companies against certain balances due to such AEP companies and to hold PJM harmless from actions that any one or more AEP companies may take with respect to PJM.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

I&M's rates are regulated by the FERC, the IURC and the MPSC. The FERC also regulates I&M's affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over certain issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. The state regulatory commissions also regulate certain intercompany transactions under various orders and affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets and wholesale power transactions. I&M's wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when a cost-based contract is negotiated and filed with the FERC or the FERC determines that I&M has "market power" in the region where the transaction occurs. Wholesale power supply contracts have been entered into with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued-up to actual costs annually.

The IURC and the MPSC regulate all of the retail distribution operations and rates of I&M's retail public utility subsidiaries on a cost basis. They also regulate the retail generation/power supply operations and rates.

The FERC also regulates I&M's wholesale transmission operations and rates. Retail transmission rates are based upon the FERC OATT rate when retail rates are unbundled in connection with restructuring. Retail transmission rates are based on formula rates included in the PJM OATT that are cost-based and are unbundled in Michigan for I&M.

In addition, the FERC regulates the TA, which allocates shared system costs and revenues among the utility subsidiaries that are parties to the agreement. The FERC also regulates the PCA. See Note 14 - Related Party Transactions for additional information.
Basis of Accounting

I&M's accounting is subject to the requirements of the IURC, the MPSC and the FERC. The financial statements have been prepared in accordance with the Uniform System of Accounts prescribed by the FERC. The principal differences from GAAP include:

- Accounting for subsidiaries on an equity basis.
- The classification of deferred fuel as noncurrent rather than current.
- The requirement to report deferred tax assets and liabilities separately rather than as a single amount.
- The classification of accrued taxes as a single amount rather than as assets and liabilities.
- The exclusion of current maturities of long-term debt from current liabilities.
- The classification of accrued non-ARO asset removal costs as accumulated depreciation rather than regulatory liabilities.
- The classification of finance lease payments as operating activities instead of financing activities.
- The classification of gains/losses from disposition of allowances as utility operating expenses rather than as operating revenues.
- The classification of PJM hourly activity for physical transactions as purchases and sales instead of net sales.
- The classification of tax assets related to the accounting guidance for "Uncertainty in Income Taxes" as a reduction to current liabilities rather than a tax benefit.
- The classification of noncurrent tax liabilities related to the accounting guidance for "Uncertainty in Income Taxes" as a current liability rather than a noncurrent liability.
- The classification of regulatory assets and liabilities related to the accounting guidance for "Accounting for Income Taxes" as separate assets and liabilities rather than as a single amount.
- The presentation of finance leased assets and their associated accumulated amortization as a single amount instead of as separate amounts.
- The classification of factored accounts receivable expense as a nonoperating expense instead of as an operating expense.
- The presentation of over/under fuel recovery in revenue rather than as a component of operating expense.
- The classification of certain nonoperating revenues as miscellaneous nonoperating income instead of as operating revenue.
- The classification of certain nonoperating expenses as miscellaneous nonoperating expense instead of as operating expense.
- The separate classification of income tax expense for operating and nonoperating activities instead of as a single income tax expense.
- The classification of DCC Fuel as a finance lease rather than consolidating in accordance with the accounting guidance for "Variable Interest Entities."
- The classification of coal procurement sales as a reduction of fuel expense rather than as revenue.
- The classification of unamortized loss on reacquired debt in deferred debits rather than in regulatory assets.
- The classification of unamortized gain on reacquired debt in deferred credits rather than in regulatory liabilities.
- The classification of accumulated deferred investment tax credits in deferred credits rather than in regulatory liabilities and deferred investment tax credits.
- The classification of plant impairment in utility plant adjustments rather than in property, plant and equipment.
- The classification of plant impairment in utility plant adjustments rather than in property, plant and equipment - accumulated depreciation and amortization.
- The classification of certain other assets and liabilities as current instead of noncurrent.
- The classification of certain other assets and liabilities as noncurrent instead of current.
- The classification of debt issuance costs as noncurrent assets instead of noncurrent liabilities.
- The classification of unrecovered plant costs as accumulated depreciation instead of regulatory assets.
- The classification of rents receivable as rents receivable instead of customer accounts receivable.
- The classification of Non-Service Cost Components of Net Periodic Benefit Cost as Operating Expense instead of Other Income (Expense).
- The classification of operating lease assets as Utility Plant rather than as a noncurrent asset.
- The classification of operating lease assets as Other Property and Investments rather than as noncurrent assets.
- The presentation of obligations under finance and operating leases as a single amount in Obligations Under Capital Leases rather than as separate items.
- The classification of certain expenses in operating income rather than operating expenses.
- The classification of interest on regulated finance leases as operating expense instead of Other Income (Expense).
- The classification of cloud computing implementation costs as Utility Plant rather than as a noncurrent asset.
- The classification of cloud computing implementation costs as Other Property and Investments rather than as a noncurrent asset.
- The classification of the amortization of certain finance leases as depreciation and amortization rather than as operating expenses.
- The classification of certain plant balances as nonutility property rather than as utility property.
- The presentation of certain property balances on a net basis in gross property rather than a split between gross property and accumulated depreciation.
- The classification of the amortization of excess SO^2 allowances as current and accrued assets rather than noncurrent assets.
- The classification of the depreciation and amortization of Rockport Unit 2 in accumulated depreciation and amortization - nonutility rather than accumulated depreciation and amortization - utility.

Accounting for the Effects of Cost-Based Regulation

I&M's financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

Use of Estimates

The preparation of these financial statements requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for doubtful accounts, long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents include Cash, Working Fund and Temporary Cash Investments on the balance sheets with original maturities of three months or less.

Supplementary Information

For the Years Ended December 31,	2023	2022
	(in millions)	
Cash was Paid for:		
Interest (Net of Capitalized Amounts)	$ 123.9	$ 116.7
Income Taxes (Net of Refunds)	108.9	11.2
Noncash Acquisitions Under Finance Leases	75.3	144.9
As of December 31,		
Construction Expenditures Included in Current and Accrued Liabilities	67.8	71.9
Nuclear Fuel Expenditures Included in Current and Accrued Liabilities	24.2	—

Special Deposits

Special Deposits include funds held by trustees primarily for margin deposits for risk management activities.

Inventory

Fossil fuel inventories and materials and supplies inventories are carried at average cost.

Accounts Receivable and Allowance for Uncollectible Accounts

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized over time as the performance obligations of delivering energy to customers are satisfied. To the extent that deliveries have occurred but a bill has not been issued, I&M accrues and recognizes, as Accrued Utility Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, through purchase agreements with I&M. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from bank conduits for a portion of its interests in the billed and unbilled receivables acquired from the affiliated utility subsidiaries. See "Securitized Accounts Receivable – AEP Credit" section of Note 13 for additional information.

Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from I&M. The assessment is performed separately for I&M which inherently contemplates any differences in geographical risk characteristics for the allowance for uncollectible accounts.

For customer accounts receivables relating to risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For miscellaneous accounts receivable, bad debt expense is recorded based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable, unless specifically identified.

In addition to these processes, management contemplates available current information, as well as any reasonable and supportable forecast information, to determine if allowances for uncollectible accounts should be further adjusted in accordance with the accounting guidance for "Credit Losses." Management's assessments contemplate expected losses over the life of the accounts receivable.

Concentrations of Credit Risk and Significant Customers

I&M does not have any significant customers that comprise 10% or more of its operating revenues for the years ended December 31, 2023 and 2022, respectively.

I&M monitors credit levels and the financial condition of its customers on a continuous basis to minimize credit risk. The regulatory commissions allow recovery in rates for a reasonable level of bad debt costs. Management believes adequate provisions for credit loss have been made in the accompanying financial statements.

Renewable Energy Credits

I&M records renewable energy credits (RECs) at cost. I&M follows the inventory model for these RECs. RECs are reported in Miscellaneous Current and Accrued Assets on the balance sheets. The purchases and sales of RECs are reported in the Operating Activities section of the statements of cash flows. RECs that are consumed to meet applicable state renewable portfolio standards are recorded in Operation Expenses at an average cost on the statements of income. The net margin on sales of RECs affects the determination of deferred fuel and REC costs.

Property, Plant and Equipment

Electric utility property, plant and equipment for rate-regulated operations are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of removal cost incurred and salvage received. These rates and the related lives are subject to periodic review.

Removal costs accrued are charged to accumulated depreciation. The costs of labor, materials and overhead incurred to operate and maintain plant and equipment are included in operating expenses.

Nuclear fuel, including nuclear fuel in the fabrication phase, is included in Net Nuclear Fuel on the balance sheets.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in-service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed or is not probable, the cost of that asset shall be written down to its then current estimated fair value, with the change charged to expense, and the asset is removed from plant-in-service or CWIP. The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Investment in Subsidiary Companies

I&M has two wholly-owned subsidiaries, Blackhawk Coal Company and Price River Coal Company that were formerly engaged in coal-mining operations. Blackhawk Coal Company currently leases and subleases portions of its Utah coal rights and land to nonaffiliated companies. Price River Coal Company which owns no land or mineral rights is inactive. Investment in the net assets of the two wholly-owned subsidiaries is carried at cost plus equity in their undistributed earnings since acquisition.

Allowance for Funds Used During Construction

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant.

Asset Retirement Obligations

I&M records ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for legal obligations for asbestos removal, the retirement of certain ash disposal facilities and the decommissioning of the Cook Plant. AROs are computed as the present value of the estimated costs associated with the future retirement of an asset and are recorded in the period in which the liability is incurred. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be decommissioned, inflation, and discount rate, which may change significantly over time. The estimated costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. I&M has identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since I&M plans to use their facilities indefinitely. The retirement obligation would only be recognized if and when I&M abandons or ceases the use of specific easements, which is not expected.

Valuation of Nonderivative Financial Instruments

The book values of Cash, Special Deposits, Working Fund, Notes Receivable from Associated Companies, Notes Payable to Associated Companies, accounts receivable and accounts payable approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For commercial activities, exchange-traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange-traded derivatives where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket-based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A portion of the Level 3 instruments have been economically hedged which limits potential earnings volatility.

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the benefit plan and nuclear trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes.

Assets in the benefits and nuclear trusts are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and equity securities. They are valued based on observable inputs, primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Investments classified as Other are valued using Net Asset Value as a practical expedient. Items classified as Other are primarily cash equivalent funds, common collective trusts, commingled funds, structured products, private equity, real estate, infrastructure and alternative credit investments. These investments do not have a readily determinable fair value or they contain redemption restrictions which may include the right to suspend redemptions under certain circumstances. Redemption restrictions may also prevent certain investments from being redeemed at the reporting date for the underlying value.

Deferred Fuel Costs

The cost of purchased electricity, fuel and related emission allowances and emission control chemicals/consumables is charged to Operation Expenses when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily using the units-of-production method. Fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as regulatory assets. These deferrals are incorporated into the development of future fuel rates billed to or refunded to customers. The amount of an over-recovery or under-recovery can also be affected by actions of the IURC and the MPSC. On a routine basis, the IURC and the MPSC reviews and/or audits I&M's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable. I&M shares the majority of its Off-system Sales margins to customers either through an active FAC or other rate mechanisms. Where the FAC or Off-system Sales sharing mechanism is capped, frozen, non-existent or not applicable to merchant operations, changes in fuel costs or sharing of off-system sales impact earnings.

Revenue Recognition

Regulatory Accounting

I&M's financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses or alternative revenues recognized in accordance with the guidance for "Regulated Operations") and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching revenue with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, assets are recorded on the balance sheets. Regulatory assets are reviewed for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, the regulatory asset is derecognized as a charge against income.

Retail and Wholesale Supply and Delivery of Electricity

I&M recognizes revenues from customers for retail and wholesale electricity sales and electricity transmission and distribution delivery services. I&M recognizes such revenues on the statements of income as the performance obligations of delivering energy to customers are satisfied. Recognized revenues include both billed and unbilled amounts.

Wholesale transmission revenue is based on FERC-approved formula rate filings made for each calendar year using estimated costs. Revenues initially recognized per the annual rate filing are compared to actual costs, resulting in the subsequent recognition of an over or under-recovered amount, with interest, that is refunded or recovered, respectively, in a future year's rates. These annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations". An estimated annual true-up is recorded by I&M in the fourth quarter of each calendar year and a final annual true-up is recognized by I&M in the second quarter of each calendar year following the filing of annual FERC reports. Any portion of the true-ups applicable to an affiliated company is recorded as Accounts Receivable from Associated Companies or Accounts Payable to Associated Companies on the balance sheets. Any portion of the true-ups applicable to third-parties is recorded as regulatory assets or regulatory liabilities on the balance sheets. See Note 16 - Revenue from Contracts with Customers for additional information.

Gross versus Net Presentation of Certain Electricity Supply and Delivery Activities

Most of the power produced at the generation plants is sold to PJM. I&M also purchases power from PJM to supply power to customers. Generally, these power sales and purchases are reported on a net basis as revenues on the statements of income. However, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are recorded gross as Operation Expenses on the statements of income.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Operation Expenses on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's facts and circumstances. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Operation Expenses on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, I&M records expenses when purchased electricity is received and when expenses are incurred. I&M defers unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

I&M engages in power, capacity and, to a lesser extent, natural gas marketing as a major power producer and participant in electricity and natural gas markets. I&M also engages in power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity risk management activities focused on markets where the AEP System owns assets and on adjacent markets. These activities include the purchase-and-sale of energy under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. Certain energy marketing and risk management transactions are with RTOs.

I&M recognizes revenues from marketing and risk management transactions that are not derivatives as the performance obligation of delivering the commodity is satisfied. Expenses from marketing and risk management transactions that are not derivatives are also recognized upon delivery of the commodity.

I&M uses MTM accounting for marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or elected normal under the normal purchase normal sale election. Unrealized MTM gains and losses are included on the balance sheets as Derivative Instrument Assets or Liabilities, as appropriate, and on the statements of income in Operating Revenues. I&M includes realized gains and losses on marketing and risk management transactions in revenue or expense based on the transaction's facts and circumstances. The unrealized MTM amounts and some realized gains and losses are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Certain qualifying marketing and risk management derivatives transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). In the event I&M designates a cash flow hedge, the cash flow hedge's gain or loss is initially recorded as a component of AOCI. When the forecasted transaction is realized and affects
net income, I&M subsequently reclassifies the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on their statements of income. See "Accounting for Cash Flow Hedging Strategies" section of Note 9 for additional information.

Levelization of Nuclear Refueling Outage Costs

In accordance with regulatory orders, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over approximately 18 months, beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins.

Maintenance

I&M expenses maintenance costs as incurred. If it becomes probable that I&M will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with its recovery in cost-based regulated revenues. I&M defers costs above the level included in base rates and amortizes those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment Tax Credits

I&M uses the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled.

When the flow-through method of accounting for temporary differences is required by a regulator to be reflected in regulated revenues (that is, when deferred taxes are not included in the cost-of-service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

I&M applies the deferral methodology for the recognition of ITCs. Deferred ITCs are amortized to income tax expense over the life of the asset that generated the credit. Amortization of deferred ITCs begins when the asset is placed in-service, except where regulatory commissions reflect ITCs in the rate-making process, then amortization begins when the utility is able to utilize the ITC on a stand-alone basis.

Transferable tax credits established by the IRA are accounted for in accordance with the accounting guidance for "Income Taxes" by I&M. Proceeds from sales of transferable tax credits are included as a component of Operating Activities on the statement of cash flows and presented as gross within the Supplementary Cash Flow Information.

I&M accounts for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." I&M classifies interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classifies penalties as Penalties on the statements of income.

Excise Taxes

As an agent for some state and local governments, I&M collects from customers certain excise taxes levied by those state or local governments on customers. I&M does not record these taxes as revenue or expense.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates.

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations.

Pension and OPEB Plans

I&M participates in an AEP sponsored qualified pension plan and two unfunded nonqualified pension plans. Substantially all I&M's employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. I&M also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees. I&M is allocated a proportionate share of benefit costs and account for their participation in these plans as multiple-employer plans. See Note 7 - Benefit Plans for additional information including significant accounting policies associated with the plans.

Investments Held in Trust for Future Liabilities

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and SNF disposal. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for the trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the investment risk of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. Management regularly reviews the actual asset allocations and periodically rebalances the investments to targeted allocations when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The objective of the investment policy for the pension fund is to maintain the funded status of the plan while providing for growth in the plan assets to offset the growth in the plan liabilities. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	30 %
Fixed Income	54 %
Other Investments	15 %
Cash and Cash Equivalents	1 %

OPEB Plans Assets	Target
Equity	58 %
Fixed Income	41 %
Cash and Cash Equivalents	1 %

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies or certain commingled funds). However, the investment
policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law.

For equity investments, the concentration limits are generally as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No individual stock may be more than 10% and 7% for pension and OPEB investments, respectively, of each manager's equity portfolio.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, each investment manager's portfolio is compared to investment grade, diversified long and intermediate benchmark indices.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and opportunistic classifications.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships to invest across the private equity investment spectrum. The private equity holdings are with multiple general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investments.

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is to provide modest incremental income with a limited increase in risk. As of December 31, 2023 and 2022, the fair value of securities on loan as part of the program was $62 million and $83 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2023 and 2022.

Trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company is held in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Nuclear Trust Funds

Nuclear decommissioning and SNF trust funds represent funds that regulatory commissions allow I&M to collect through rates to fund future decommissioning and SNF disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP, I&M or their affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

I&M maintains trust funds for each regulatory jurisdiction. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by an external investment manager that must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

I&M records securities held in these trust funds in Other Special Funds on its balance sheets. I&M records these securities at fair value. I&M classifies debt securities in the trust funds as available-for-sale due to their long-term purpose.

Other-than-temporary impairments for investments in debt securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the debt and equity investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. I&M records unrealized gains, unrealized losses and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. See the "Nuclear Contingencies" section of Note 6 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 10 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners.

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2023 through February 26, 2024, the date that AEP's Form 10-K was issued, and has updated such evaluation for disclosure purposes through April 9, 2024. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

2. <u>NEW ACCOUNTING STANDARDS</u>

During the FASB's standard-setting process and upon issuance of final standards, management reviews the new accounting literature to determine its relevance, if any, to I&M's business. The following standards will impact I&M's financial statements.

ASU 2023-09 "Improvements to Income Tax Disclosures" (ASU 2023-09)

In December 2023, the FASB issued ASU 2023-09, to address investors' suggested enhancements to (a) better understand an entity's exposure to potential changes in jurisdictional tax legislation and the ensuing risks and opportunities, (b) assess income tax information that affects cash flow forecasts and capital allocation decisions and (c) identify potential opportunities to increase future cash flows.

The new standard requires an annual rate reconciliation disclosure of the following categories regardless of materiality: state and local income tax net of federal income tax effect, foreign tax effects, effect of changes in tax laws or rates enacted in the current period, effect of cross-border tax laws, tax credits, changes in valuation allowances, nontaxable or nondeductible items and changes in unrecognized tax benefits.

The new standard also requires an annual disclosure of the amount of income taxes paid (net of refunds received) disaggregated by federal, state and foreign taxes and by individual jurisdictions that are equal to or greater than 5 percent of total income taxes paid. Disclosure of income (loss) from continuing operations before income tax expense (benefit) disaggregated between domestic and foreign jurisdictions and income tax expense (benefit) from continuing operations disaggregated by federal, state and foreign jurisdictions is required.
The new standard removes the requirement to disclose the cumulative amount of each type of temporary difference when a deferred tax liability is not recognized because of the exceptions to comprehensive recognition of deferred taxes related to subsidiaries and corporate joint ventures.

The amendments in the new standard may be applied on either a prospective or retrospective basis for public business entities for fiscal years beginning after December 15, 2024 with early adoption permitted. Management has not yet made a decision to early adopt the amendments to this standard or how to apply them.

ASU 2023-07 "Improvements to Reportable Segment Disclosures" (ASU 2023-07)

In November 2023, the FASB issued ASU 2023-07, to address investors' observations that there is limited information disclosed about segment expenses and to better understand expense categories and amounts included in segment profit or loss. The new standard requires annual and interim disclosure of (a) the categories and amounts of significant segment expenses (determined by management using both qualitative and quantitative factors) that are regularly provided to the chief operating decision maker (CODM) and included within each reported measure of segment profit or loss, (b) the amounts and a qualitative description of "other segment items", defined as the difference between reported segment revenues less the significant segment expenses and each reported measure of segment profit or loss disclosed, (c) reportable segment profit or loss and assets that are currently only required annually, (d) the CODM's title and position, and an explanation of how the CODM uses the reported measure(s) of segment profit or loss in assessing segment performance and deciding how to allocate resources and (e) a requirement that entities with a single reportable segment provide all disclosures required by ASU 2023-07 and all existing segment disclosures in Topic 280. Additionally, this new standard allows disclosure of one or more of additional profit or loss measures if the CODM uses more than one measure provided that at least one of the disclosed measures is determined in a manner "most consistent with the measurement principles under GAAP". If multiple measures are presented, additional disclosure is required about how the CODM uses each measure to assess performance and decide how to allocate resources.

The amendments in the new standard are effective on a retrospective basis for all entities for fiscal years beginning after December 15, 2023 and interim periods within fiscal periods beginning after December 15, 2024 with early adoption permitted. Management does not plan to early adopt the amendments to this standard.

3. <u>COMPREHENSIVE INCOME</u>

I&M's balance and activity in AOCI was not material for the years ended December 31, 2023 and December 31, 2022.

4. RATE MATTERS

I&M is involved in rate and regulatory proceedings at the FERC and the IURC and the MPSC. Rate matters can have a material impact on net income, cash flows and possibly financial condition. I&M's recent significant rate orders and pending rate filings are addressed in this note.

Michigan Power Supply Cost Recovery (PSCR) Reconciliation

In April 2023, I&M received intervenor testimony in I&M's 2021 PSCR Reconciliation for the 12-month period ending December 31, 2021, recommending disallowances of purchased power costs of $18 million associated with the OVEC Inter-Company Power Agreement (ICPA) and the UPA with AEGCo that were alleged to be above market in applying the MPSC's Code of Conduct rules. Michigan staff submitted testimony in I&M's 2021 PSCR Reconciliation with no recommended disallowances for PSCR costs incurred, including those associated with the OVEC ICPA and the AEGCo UPA. Michigan staff also recommended several options to address I&M's shortfall in achieving Michigan's annual one percent energy waste reduction savings level, resulting in potential future disallowed costs of up to approximately $14 million. In June 2023, Michigan staff submitted rebuttal testimony to update their calculation of the 2021 market proxy price resulting in a recommended disallowance of approximately $1 million related to the OVEC ICPA.

In January 2024, I&M received staff testimony in I&M's 2022 PSCR Reconciliation for the 12-month period ending December 31, 2022 recommending disallowances of purchased power costs of $2 million associated with the OVEC ICPA that were alleged to be above market in applying the MPSC's Code of Conduct rules. Similar to the 2021 PSCR Reconciliation, Michigan staff also recommended several options to address I&M's shortfall in achieving Michigan's annual one percent energy waste reduction savings level, resulting in potential future disallowed costs of up to approximately $6 million.

MPSC orders on I&M's 2021 and 2022 PSCR Reconciliations are expected in the first half of 2024. If any PSCR costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2023 Indiana Base Rate Case

In August 2023, I&M filed a request with the IURC for a $116 million annual increase in Indiana base rates based upon a 2024 forecasted test year, a proposed 10.5% ROE and a proposed capital structure of 48.8% debt and 51.2% common equity. I&M proposed that the annual increase in base rates be implemented in two steps, with the first increase effective in mid-2024, following an IURC order, and the second increase effective in January 2025. The proposed annual increase includes a $41 million increase related to depreciation expense, driven by increased depreciation rates and increased capital investments, and a $15 million increase related to storm expenses. I&M's Indiana base case filing requests recovery of certain historical period regulatory asset balances and proposes deferral accounting for certain future investments and tax related issues, including corporate alternative minimum tax expense and PTCs related to the Cook Plant.
In December 2023, I&M and intervenors reached a settlement agreement that was submitted to the IURC recommending a two-step increase in Indiana rates with a $28 million annual increase effective upon an IURC order and the remaining $34 million annual increase effective in January 2025. The recommended revenue increase includes: (a) a 9.85% ROE, (b) a two-step update of I&M's capital structure with a capital structure of 50% for both debt and common equity effective upon an IURC order and I&M will submit an updated capital structure in January 2025 with the common equity component adjusted to no more than 51.2%, (c) a $25 million increase related to depreciation expense and (d) an $11 million increase related to storm expenses.

A hearing was held in January 2024 and an order is expected in the second quarter of 2024. If any costs included in this filing are not approved for recovery, it could reduce future net income and cash flows and impact financial condition.

2023 Michigan Base Rate Case

In September 2023, I&M filed a request with the MPSC for a $34 million annual increase in Michigan base rates based upon a 2024 forecasted test year, a proposed 10.5% ROE and a capital structure of 49.4% debt and 50.6% common equity. The proposed annual increase includes an $11 million annual increase in depreciation expense driven by increased capital investment. I&M's Michigan base case filing requests recovery of certain historical period regulatory asset balances and proposes deferral accounting for certain future investments and tax related issues, including corporate alternative minimum tax expense and PTCs related to the Cook Plant.

In January 2024, Michigan Staff and various intervenors submitted testimony recommending changes in base rates ranging from a $6 million annual decrease to a $19 million annual increase. These changes are based on ROEs ranging from 9.7% to 9.9% and capital structures ranging from 49.4% debt and 50.6% equity to 52% debt and 48% equity. Intervenors also proposed in testimony certain disallowances related to existing regulatory assets totaling approximately $5 million, the exclusion of CAMT from any future deferrals and the prospective inclusion of PTCs related to the Cook Plant in I&M's PSCR.

A hearing was held in February 2024. If any costs included in this filing are not approved for recovery, it could reduce future net income and cash flows and impact financial condition.

Request to Update AEGCo Depreciation Rates

In October 2022, AEP, on behalf of AEGCo, submitted proposed revisions to AEGCo's depreciation rates for its 50% ownership interest in Rockport Plant, Unit 1 and Unit 2, reflected in the UPA between AEGCo and I&M. The proposed depreciation rates for these assets reflect an estimated 2028 retirement date for the Rockport Plant. AEGCo's previous FERC-approved depreciation rates for Rockport Plant, Unit 1 were based upon a December 31, 2028 estimated retirement date while AEGCo's previous FERC-approved depreciation rates for Rockport Plant, Unit 2 leasehold improvements were based upon a December 31, 2022 estimated retirement date in conjunction with the termination of the Rockport Plant, Unit 2 lease.

In December 2022, the FERC issued an order approving the proposed AEGCo Rockport depreciation rates effective January 1, 2023, subject to further review and a potential refund. The FERC established a separate proceeding to review: (a) AEGCo's acquisition value for the Rockport Plant, Unit 2 base generating asset (original cost and accumulated depreciation), (b) the appropriateness of including future capital additions as stated components in proposed depreciation rates, in light of the UPA's formula rate mechanism, (c) the appropriateness of applying two different depreciation rates to a single asset common to both units and (d) the accounting and regulatory treatment of Rockport Plant, Unit 2 costs of removal and related AROs. In August 2023, AEGCo reached a settlement agreement with the FERC Trial Staff that resolves all issues set for hearing. In September 2023, the settlement agreement was certified to the FERC as uncontested. An order from the FERC on this settlement agreement is expected in 2024. If the FERC finalizes the settlement agreement as proposed, management anticipates the results of the order will not have a material impact on financial condition, results of operations or cash flows.

FERC 2021 PJM and SPP Transmission Formula Rate Challenge

I&M and other AEP subsidiaries transitioned to stand-alone treatment of NOLCs in its PJM and SPP transmission formula rates beginning with the 2022 projected transmission revenue requirements and 2021 true-up to actual transmission revenue requirements and provided notice of this change in informational filings made with the FERC. Stand-alone treatment of the NOLCs for transmission formula rates increased the annual revenue requirements for years 2023, 2022 and 2021 by $60 million, $69 million and $78 million, respectively.

In March 2023 and May 2023, certain joint customers submitted a complaint and a formal challenge at the FERC related to the 2022 Annual Update of the 2021 Transmission Formula Rates of the AEP transmission owning subsidiaries within PJM and SPP, respectively. These challenges primarily relate to stand-alone treatment of NOLCs in the transmission formula rates of the AEP transmission owning subsidiaries. AEPSC, on behalf of the AEP transmission owning subsidiaries within PJM and SPP, filed answers to the joint formal challenge and complaint with the FERC in the second quarter of 2023.

In January 2024, the FERC issued two orders, granting the joint customers' challenges related to stand-alone treatment of NOLCs in the 2021 Transmission Formula Rates of the AEP transmission owning subsidiaries within PJM and SPP. The FERC directed the AEP transmission owning subsidiaries within PJM and SPP to provide refunds with interest on all amounts collected for the 2021 rate year, and for such refunds to be reflected in the annual update for the next rate year. In February 2024, AEPSC on behalf of the AEP transmission owning subsidiaries within PJM and SPP filed requests with the FERC that it grant rehearing and reverse findings in its January 2024 orders or establish hearing procedures to address outstanding factual issues. In March 2024, the FERC denied AEPSC's requests for rehearing of the January 2024 orders by operation of law and stated it may address the requests for rehearing in future orders.

As a result of the January 2024 FERC orders, I&M's 2022 and 2023 income statements cumulatively reflect a provision for refund for the probable refund of all NOLC revenues included in transmission formula rates for years 2023, 2022 and 2021. The probable refunds to affiliated and nonaffiliated customers are reflected as Accumulated Provision for Rate Refunds on the balance sheets. Refunds probable to be received by affiliated companies, resulting in a reduction to affiliated transmission expense, were deferred as an increase to Regulatory Liabilities on the balance sheets where management expects that refunds would be returned to retail customers through authorized retail jurisdiction rider mechanisms. The FERC directed cash refunds with interest related to the 2021 rate year to occur through the annual update for the next rate year, which will be invoiced by PJM and SPP primarily in 2025. I&M and other AEP subsidiaries have not yet been directed to make cash refunds related to the 2022 or 2023 rate years.

The impact of the FERC's orders on the pretax net income of I&M was not material.

5. EFFECTS OF REGULATION

Regulatory Assets:	December 31, 2023	2022	Remaining Recovery Period
	(in millions)		
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Other Regulatory Assets Pending Final Regulatory Approval	$ 0.2	$ 0.1	
Total Regulatory Assets Currently Earning a Return	0.2	0.1	
Regulatory Assets Currently Not Earning a Return			
Income Tax Assets	103.0	87.7	
Storm-Related Costs - Indiana	29.7	21.6	
Other Regulatory Assets Pending Final Regulatory Approval	3.3	2.0	
Total Regulatory Assets Currently Not Earning a Return	136.0	111.3	
Total Regulatory Assets Pending Final Regulatory Approval	136.2	111.4	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Cook Plant Uprate Project	22.9	25.3	10 years
Rockport Plant Dry Sorbent Injection System and Selective Catalytic Reduction	21.1	25.6	5 years
Under-recovered Fuel Costs - Michigan	14.8	9.0	1 year
Deferred Cook Plant Life Cycle Management Project Costs - Michigan, FERC	11.1	12.1	11 years
Cook Plant Turbine - Indiana	8.4	9.0	15 years
Other Regulatory Assets Approved for Recovery	17.5	20.6	various
Total Regulatory Assets Currently Earning a Return	95.8	101.6	
Regulatory Assets Currently Not Earning a Return			
Income Tax Assets	300.7	293.1	(a)
Cook Plant Nuclear Refueling Outage Levelization	55.7	81.2	2 years
Pension and OPEB Funded Status	25.4	26.9	12 years
Excess SO_2 Allowance Inventory - Indiana	14.8	—	5 years
Environmental Cost Rider - Indiana	8.1	6.6	2 years
Postemployment Benefits	7.0	7.7	3 years
Under-recovered Fuel Costs - Indiana	—	38.1	
Demand Side Management - Indiana	—	10.3	
Other Regulatory Assets Approved for Recovery	21.0	19.7	various
Total Regulatory Assets Currently Not Earning a Return	432.7	483.6	
Total Regulatory Assets Approved for Recovery	528.5	585.2	
Total FERC Account 182.3 Regulatory Assets	$ 664.7	$ 696.6	

(a) Recovered over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets.

Regulatory Liabilities:	December 31, 2023	2022	Remaining Refund Period
	(in millions)		
Regulatory Liabilities pending final regulatory approval:			
Regulatory Liabilities Currently Not Paying a Return			
FERC 2021 Transmission Formula Rate Challenge Refunds	$ 22.8	$ —	2 years
Total Regulatory Liabilities Currently Not Paying a Return	22.8	—	
Total Regulatory Liabilities Pending Final Regulatory Approval	22.8	—	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Income Tax Liabilities (a)	417.6	461.7	(b)
Renewable Energy Surcharge - Michigan	26.6	23.2	2 years
Other Regulatory Liabilities Approved for Payment	—	3.0	various
Total Regulatory Liabilities Currently Paying a Return	444.2	487.9	
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	1,721.9	1,318.5	(c)
Spent Nuclear Fuel	47.6	45.8	(c)
Over-recovered Fuel Costs - Indiana	23.2	—	1 year
Demand Side Management - Indiana	16.7	—	2 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	14.1	34.2	
Other Regulatory Liabilities Approved for Payment	4.9	8.5	various
Total Regulatory Liabilities Currently Not Paying a Return	1,828.4	1,407.0	
Total Regulatory Liabilities Approved for Payment	2,272.6	1,894.9	
Total FERC 254 Account Regulatory Liabilities	$ 2,295.4	$ 1,894.9	

(a) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Refunded over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements were $25 million and $42 million for the years ended December 31, 2023 and 2022, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2023 is to be refunded over 5 years.
(c) Relieved when plant is decommissioned.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

I&M is subject to certain claims and legal actions arising in the ordinary course of business. In addition, I&M's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. Management accrues contingent liabilities only when management concludes that it is both probable that a liability has been incurred at the date of the financial statements and the amount of loss can be reasonably estimated. When management determines that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, management discloses such contingencies and the possible loss or range of loss if such estimate can be made. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the maximum possible loss exposure. Circumstances change over time and actual results may vary significantly from estimates.

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements.

COMMITMENTS

I&M has substantial commitments for fuel, energy and capacity contracts as part of the normal course of business. Certain contracts contain penalty provisions for early termination.

In accordance with the accounting guidance for "Commitments", the following table summarizes I&M's actual contractual commitments as of December 31, 2023:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 144.4	$ 232.3	$ 130.8	$ 241.6	$ 749.1
Energy and Capacity Purchase Contracts	127.0	253.8	236.6	182.2	799.6
Total	$ 271.4	$ 486.1	$ 367.4	$ 423.8	$ 1,548.7

(a) Represents contractual commitments to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.

GUARANTEES

Liabilities for guarantees are recorded in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third-parties unless specified below.

Letters of Credit

Standby letters of credit are entered into with third-parties. These letters of credit are issued in the ordinary course of business and cover items such as natural gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

AEP has $4 billion and $1 billion revolving credit facilities due in March 2027 and 2025, respectively, under which up to $1.2 billion may be issued as letters of credit on behalf of its subsidiaries. As of December 31, 2023, no letters of credit were issued under the revolving credit facility.

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under six uncommitted facilities totaling $450 million. I&M's maximum future payments for letters of credit issued under the uncommitted facilities as of December 31, 2023 was $3 million with a maturity date of September 2024.

Indemnifications and Other Guarantees

Contracts

I&M enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2023, there were no material liabilities recorded for any indemnifications.

AEPSC conducts power purchase-and-sale activity on behalf of I&M who are jointly and severally liable for activity conducted on their behalf.

Lease Obligations

I&M leases equipment under master lease agreements. See "Master Lease Agreements" section of Note 12 for additional information.

ENVIRONMENTAL CONTINGENCIES

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generation plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and non-hazardous materials. I&M currently incurs costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2023, I&M received information requests for three sites that could lead to a Potentially Responsible Party (PRP) designation. In those instances where a PRP or defendant has been named, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

Management evaluates the potential liability for each Superfund site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often non-hazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. As of December 31, 2023, management's estimates do not anticipate material clean-up costs for identified Superfund sites.

NUCLEAR CONTINGENCIES

I&M owns and operates the two-unit 2,296 MW Cook Plant under licenses granted by the NRC. I&M has a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. Management is currently evaluating applying for license extensions for both units. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generation units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial.

Decommissioning and Low-Level Waste Accumulation Disposal

The costs to decommission a nuclear plant are affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of Cook Plant. The most recent decommissioning cost study was performed in 2021. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste was $2.2 billion in 2021 non-discounted dollars, with additional ongoing costs of $7 million per year for post decommissioning storage of SNF and an eventual cost of $33 million for the subsequent decommissioning of the SNF storage facility, also in 2021 non-discounted dollars. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were $2 million and $2 million for the years ended December 31, 2023 and 2022, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2023 and 2022, the total decommissioning trust fund balances were $3.5 billion and $3.0 billion, respectively. The increase in the trust fund balance was driven by favorable investment performance in 2023. Trust fund earnings increase the fund assets and may decrease the amount remaining to be recovered from customers. Trust fund losses decrease the fund assets and may increase the amount remaining to be recovered from customers. The decommissioning costs (including unrealized gains and losses, interest and trust funds expenses) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to establish rates designed to collect the estimated costs of decommissioning the Cook Plant. However, future net income and cash flows would be reduced and financial condition could be impacted if the cost of SNF disposal and decommissioning increases and cannot be recovered.

Spent Nuclear Fuel Disposal

The federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one-mill per KWh for fuel consumed after April 6, 1983 at the Cook Plant was collected from customers and remitted to the DOE through May 14, 2014. In May 2014, pursuant to court order from the U.S Court of Appeals for the District of Columbia Circuit, the DOE adjusted the fee to $0. As of December 31, 2023 and 2022, fees and related interest of $300 million and $286 million, respectively, for fuel consumed prior to April 7, 1983 were recorded as Long-term Debt and funds collected from customers along with related earnings totaling $348 million and $330 million, respectively, to pay the fee, were recorded as part of Other Special Funds on the balance sheets. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

In 2011, I&M signed a settlement agreement with the federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government's delay in accepting SNF for permanent storage. Under the settlement agreement, I&M received $21 million and $3 million in 2023 and 2022, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2023. The proceeds reduced costs for dry cask storage. As of December 31, 2023 and 2022, I&M deferred $12 million and $21 million, respectively, in Miscellaneous Current and Accrued Assets and $9 million and $3 million, respectively, in Miscellaneous Deferred Debits on the balance sheets for dry cask storage and related operation and maintenance costs for recovery under this agreement. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 10 for additional information.

Nuclear Insurance

I&M carries nuclear property insurance of $2.7 billion to cover a nuclear incident at Cook Plant including coverage for decontamination and stabilization, as well as premature decommissioning caused by a nuclear incident. Insurance coverage for a nonnuclear property incident at Cook Plant is $500 million. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes industry mutual insurers for the placement of this insurance coverage. Coverage from these industry mutual insurance programs require a contingent financial obligation of up to $42 million for I&M, which is assessable if the insurer's financial resources would be inadequate to pay for industry losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public nuclear liability arising from a nuclear incident of $16.3 billion and applies to any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $500 million of primary coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $332 million per nuclear incident on Cook Plant's reactors payable in annual installments of $49 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is covered for public nuclear liability for the first $500 million through commercially available insurance. The next level of liability coverage of up to $15.8 billion would be covered by claim premium assessments made under the Price-Anderson Act. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds, I&M would seek recovery of those amounts from customers through a rate increase. If recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

I&M maintains insurance coverage normal and customary for electric utilities, subject to various deductibles. I&M also maintains property and casualty insurance that may cover certain physical damage or third-party injuries caused by cybersecurity incidents. Insurance coverage includes all risks of physical loss or damage to nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from certain claims made by third-parties and are in excess of retentions absorbed by I&M. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers. See "Nuclear Contingencies" section above for additional information.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to a cybersecurity incident or damage to the Cook Plant and costs of replacement power in the event of an incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could reduce future net income and cash flows and impact financial condition.

7. <u>BENEFIT PLANS</u>

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Fair Value Measurements of Assets and Liabilities" and "Investments Held in Trust for Future Liabilities" sections of Note 1.

I&M participates in an AEP sponsored qualified pension plan and two unfunded non-qualified pension plans. Substantially all of I&M's employees are covered by the qualified plan or both the qualified and a non-qualified pension plan. I&M also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees.

I&M recognizes the funded status associated with defined benefit pension and OPEB plans on the balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. I&M recognizes an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. I&M records a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that for rate-making purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions used in the measurement of I&M's benefit obligations are shown in the following table:

Assumption	Pension Plans 2023	Pension Plans 2022	OPEB 2023	OPEB 2022
	December 31,			
Discount Rate	5.15%	5.50%	5.15%	5.50%
Interest Crediting Rate	4.00%	4.25%	NA	NA
Rate of Compensation Increase	5.05% (a)	5.00% (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.
NA Not applicable.

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2023, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% per year, with the average increase shown in the table above.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions used in the measurement of benefit costs are shown in the following table:

Assumption	Pension Plans 2023	Pension Plans 2022	OPEB 2023	OPEB 2022
	Year Ended December 31,			
Discount Rate	5.50 %	2.90 %	5.50 %	2.90 %
Interest Crediting Rate	4.25 %	4.00 %	NA	NA
Expected Return on Plan Assets	7.50 %	5.25 %	7.25 %	5.50 %
Rate of Compensation Increase	5.05 % (a)	5.00 % (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.
NA Not applicable.

The expected return on plan assets was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, third-party forecasts and current prospects for economic growth.

The health care trend rate assumptions used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	December 31, 2023	December 31, 2022
Initial	7.00 %	7.50 %
Ultimate	4.50 %	4.50 %
Year Ultimate Reached	2030	2029

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. Management monitors the plans to control security diversification and ensure compliance with the investment policy. As of December 31, 2023, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets, Funded Status and Amounts Recognized on the Balance Sheets

For the year ended December 31, 2023, the pension plans had an actuarial loss primarily due to a decrease in the discount rate, and to a lesser extent the effect of demographic experience (updated census data on January 1, 2023). These losses were partially offset by decreasing the cash balance account interest crediting rate. For the year ended December 31, 2023, the OPEB plans had an actuarial loss primarily due to discount rates, as well as actual net benefit payments above expected. These losses were partially offset by updated per capita cost assumptions. For the year ended December 31, 2022, the pension plans had an actuarial gain primarily due to an increase in the discount rate and was partially offset by increases in the assumed lump sum conversion rate and cash balance account interest crediting rate. For the year ended December 31, 2022, the OPEB plans had an actuarial gain primarily due to an increase in the discount rate and updated per capita cost assumptions. The OPEB plans gains were partially offset by a projected reduction in the Employer Group Waiver Program catastrophic reinsurance offset provided to AEP, resulting from the Inflation Reduction Act as well as an increase in the health care cost trend assumption. The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets, funded status and the presentation on the balance sheets. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans 2023	Pension Plans 2022	OPEB 2023	OPEB 2022
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 466.8	$ 612.1	$ 101.9	$ 118.6
Service Cost	11.9	16.2	0.6	0.9
Interest Cost	24.9	17.0	5.4	3.4
Actuarial (Gain) Loss	8.5	(138.0)	3.2	(8.7)
Benefit Payments	(35.1)	(40.5)	(18.3)	(18.3)
Participant Contributions	—	—	6.0	6.0
Benefit Obligation as of December 31,	$ 477.0	$ 466.8	$ 98.8	$ 101.9
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 533.7	$ 681.5	$ 190.5	$ 248.7
Actual Gain (Loss) on Plan Assets	51.5	(107.4)	26.4	(45.9)
Company Contributions	0.5	0.1	—	—
Participant Contributions	—	—	6.0	6.0
Benefit Payments	(35.1)	(40.5)	(18.3)	(18.3)
Fair Value of Plan Assets as of December 31,	$ 550.6	$ 533.7	$ 204.6	$ 190.5
Funded Status as of December 31,	$ 73.6	$ 66.9	$ 105.8	$ 88.6

	Pension Plans 2023	Pension Plans 2022	OPEB 2023	OPEB 2022
	December 31, (in millions)			
Special Funds – Prepaid Benefit Costs	$ 74.8	$ 68.5	$ 105.8	$ 88.6
Miscellaneous Current and Accrued Liabilities – Short-term Benefit Liability	—	(0.1)	—	—
Accumulated Provision for Pensions and Benefits – Long-term Benefit Liability	(1.2)	(1.5)	—	—
Funded Status	$ 73.6	$ 66.9	$ 105.8	$ 88.6

Amounts Included in Regulatory Assets, Deferred Income Taxes and AOCI

The following tables show the components of the plans included in regulatory assets, Accumulated Deferred Income Taxes, and income tax expense and the items attributable to the change in these components:

Components	Pension Plans 2023	Pension Plans 2022	OPEB 2023	OPEB 2022
	December 31,			
	(in millions)			
Net Actuarial (Gain) Loss	$ (5.8)	$ (6.9)	$ 28.7	$ 40.2
Prior Service Credit	—	—	(3.7)	(12.4)
Recorded as				
Regulatory Assets	$ 6.4	$ 4.8	$ 19.0	$ 22.1
Deferred Income Taxes	(2.6)	(2.4)	1.3	1.2
Net of Tax AOCI	(9.6)	(9.3)	4.7	4.5

Components	Pension Plans 2023	Pension Plans 2022	OPEB 2023	OPEB 2022
	(in millions)			
Actuarial (Gain) Loss During the Year	$ 1.2	$ 1.8	$ (9.6)	$ 50.9
Amortization of Actuarial Loss	(0.1)	(7.1)	(1.9)	—
Amortization of Prior Service Credit	—	—	8.7	9.7
Change for the Year Ended December 31,	$ 1.1	$ (5.3)	$ (2.8)	$ 60.6

Determination of Pension Expense

The determination of pension expense or income is based on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return.

Pension and OPEB Assets

The fair value tables within Pension and OPEB Assets present the classification of assets for AEP within the fair value hierarchy. All Level 1, 2, 3 and Other amounts can be allocated to I&M using the percentages in the table below:

Pension Plan 2023	Pension Plan 2022	OPEB 2023	OPEB 2022
December 31,			
13.4 %	12.9 %	12.2 %	12.3 %

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2023:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 411.3	$ —	$ —	$ —	$ 411.3	10.0 %
International	389.8	—	—	—	389.8	9.5 %
Common Collective Trusts (b)	—	—	—	420.9	420.9	10.2 %
Subtotal – Equities	801.1	—	—	420.9	1,222.0	29.7 %
Fixed Income (a):						
United States Government and Agency Securities	8.3	1,099.2	—	—	1,107.5	26.9 %
Corporate Debt	—	894.8	—	—	894.8	21.7 %
Foreign Debt	—	167.1	—	—	167.1	4.1 %
State and Local Government	—	38.7	—	—	38.7	0.9 %
Other – Asset Backed	—	1.3	—	—	1.3	— %
Subtotal – Fixed Income	8.3	2,201.1	—	—	2,209.4	53.6 %
Infrastructure (b)	—	—	—	101.4	101.4	2.5 %
Real Estate (b)	—	—	—	239.3	239.3	5.8 %
Alternative Investments (b)	—	—	—	241.8	241.8	5.8 %
Cash and Cash Equivalents (b)	—	51.0	—	33.8	84.8	2.1 %
Other – Pending Transactions and Accrued Income (c)	—	—	0.1	19.4	19.5	0.5 %
Total	$ 809.4	$ 2,252.1	$ 0.1	$ 1,056.6	$ 4,118.2	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2023:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 540.6	$ —	$ —	$ —	$ 540.6	32.3 %
International	288.4	—	—	—	288.4	17.2 %
Common Collective Trusts (a)	—	—	—	131.6	131.6	7.9 %
Subtotal – Equities	829.0	—	—	131.6	960.6	57.4 %
Fixed Income:						
Common Collective Trust – Debt (a)	—	—	—	146.7	146.7	8.8 %
United States Government and Agency Securities	1.4	163.3	—	—	164.7	9.8 %
Corporate Debt	—	149.0	—	—	149.0	8.9 %
Foreign Debt	—	28.6	—	—	28.6	1.7 %
State and Local Government	41.5	7.8	—	—	49.3	3.0 %
Other - Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	42.9	348.9	—	146.7	538.5	32.2 %
Trust Owned Life Insurance:						
International Equities	—	22.3	—	—	22.3	1.3 %
United States Bonds	—	130.0	—	—	130.0	7.8 %
Subtotal – Trust Owned Life Insurance	—	152.3	—	—	152.3	9.1 %
Cash and Cash Equivalents (a)	25.9	—	—	2.9	28.8	1.7 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	(6.9)	(6.9)	(0.4)%
Total	$ 897.8	$ 501.2	$ —	$ 274.3	$ 1,673.3	100.0 %

(a) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2022:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 347.6	$ —	$ —	$ —	$ 347.6	8.4 %
International	398.4	—	—	—	398.4	9.7 %
Common Collective Trusts (b)	—	—	—	379.9	379.9	9.2 %
Subtotal – Equities	746.0	—	—	379.9	1,125.9	27.3 %
Fixed Income (a):						
United States Government and Agency Securities	(0.6)	1,071.4	—	—	1,070.8	26.0 %
Corporate Debt	—	891.7	—	—	891.7	21.6 %
Foreign Debt	—	140.2	—	—	140.2	3.4 %
State and Local Government	—	37.0	—	—	37.0	0.9 %
Other – Asset Backed	—	0.8	—	—	0.8	— %
Subtotal – Fixed Income	(0.6)	2,141.1	—	—	2,140.5	51.9 %
Infrastructure (b)	—	—	—	109.2	109.2	2.6 %
Real Estate (b)	—	—	—	276.9	276.9	6.7 %
Alternative Investments (b)	—	—	—	319.7	319.7	7.8 %
Cash and Cash Equivalents (b)	—	64.9	—	58.3	123.2	3.0 %
Other – Pending Transactions and Accrued Income (c)	—	—	—	29.3	29.3	0.7 %
Total	$ 745.4	$ 2,206.0	$ —	$ 1,173.3	$ 4,124.7	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2022:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 414.1	$ —	$ —	$ —	$ 414.1	26.7 %
International	265.0	—	—	—	265.0	17.1 %
Common Collective Trusts (a)	—	—	—	169.1	169.1	10.9 %
Subtotal – Equities	679.1	—	—	169.1	848.2	54.7 %
Fixed Income:						
Common Collective Trust – Debt (a)	—	—	—	120.3	120.3	7.8 %
United States Government and Agency Securities	0.1	155.8	—	—	155.9	10.1 %
Corporate Debt	—	141.5	—	—	141.5	9.1 %
Foreign Debt	—	21.0	—	—	21.0	1.4 %
State and Local Government	62.9	7.8	—	—	70.7	4.6 %
Subtotal – Fixed Income	63.0	326.1	—	120.3	509.4	33.0 %
Trust Owned Life Insurance:						
International Equities	—	46.7	—	—	46.7	3.0 %
United States Bonds	—	110.3	—	—	110.3	7.1 %
Subtotal – Trust Owned Life Insurance	—	157.0	—	—	157.0	10.1 %
Cash and Cash Equivalents (a)	23.2	—	—	6.7	29.9	1.9 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	4.8	4.8	0.3 %
Total	$ 765.3	$ 483.1	$ —	$ 300.9	$ 1,549.3	100.0 %

(a) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

Accumulated Benefit Obligation

The accumulated benefit obligation for the pension plans is as follows:

Accumulated Benefit Obligation	December 31, 2023	2022
	(in millions)	
Qualified Pension Plan	$ 450.3	$ 443.8
Nonqualified Pension Plans	0.7	1.2
Total	$ 451.0	$ 445.0

Obligations in Excess of Fair Values

The tables below show the underfunded pension plans that had obligations in excess of plan assets.

Projected Benefit Obligation

	December 31, 2023	2022
	(in millions)	
Projected Benefit Obligation	$ 1.2	$ 1.6
Fair Value of Plan Assets	—	—
Underfunded Projected Benefit Obligation	$ (1.2)	$ (1.6)

Accumulated Benefit Obligation

	December 31, 2023	2022
	(in millions)	
Accumulated Benefit Obligation	$ 0.7	$ 1.2
Fair Value of Plan Assets	—	—
Underfunded Accumulated Benefit Obligation	$ (0.7)	$ (1.2)

Estimated Future Benefit Payments and Contributions

I&M expects contributions and payments for the pension plans to be immaterial during 2024. For the pension plans, this amount includes the payment of unfunded nonqualified benefits plus contributions to the qualified trust fund of at least the minimum amount required by the Employee Retirement Income Security Act. For the qualified pension plan, I&M may also make additional discretionary contributions to maintain the funded status of the plan.

The table below reflects the total benefits expected to be paid from the plan or from I&M's assets. The payments include the participants' contributions to the plan for their share of the cost. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for the pension benefits and OPEB are as follows:

	Estimated Payments	
	Pension Plans	OPEB
	(in millions)	
2024	$ 39.0	$ 15.2
2025	39.7	15.7
2026	39.7	15.7
2027	39.8	15.4
2028	39.4	15.0
Years 2029 to 2033, in Total	189.4	69.7

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost (credit) for the plans:

	Pension Plans		OPEB	
	Years Ended December 31,			
	2023	2022	2023	2022
	(in millions)			
Service Cost	$ 11.9	$ 16.2	$ 0.6	$ 0.9
Interest Cost	24.9	17.0	5.4	3.4
Expected Return on Plan Assets	(44.2)	(32.4)	(13.5)	(13.7)
Amortization of Prior Service Credit	—	—	(8.7)	(9.7)
Amortization of Net Actuarial Loss	0.1	7.1	1.9	—
Net Periodic Benefit Cost (Credit)	(7.3)	7.9	(14.3)	(19.1)
Capitalized Portion	(3.6)	(4.6)	(0.2)	(0.3)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ (10.9)	$ 3.3	$ (14.5)	$ (19.4)

American Electric Power System Retirement Savings Plan

I&M participates in an AEP sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions to the retirement savings plans for the years ended December 31, 2023 and 2022 were $11 million and $11 million, respectively.

8. BUSINESS SEGMENTS

I&M has one reportable segment, an electricity generation, transmission and distribution business. I&M's other activities are insignificant.

9. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of I&M.

I&M is exposed to certain market risks as major power producer and participant in the electricity, capacity, natural gas, coal and emission allowance markets. These risks include commodity price risks which may be subject to capacity risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact I&M due to changes in the underlying market prices or rates. Management utilizes derivative instruments to manage these risks.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes which focus on seizing market opportunities to create value driven by expected changes in the market prices of the commodities. To accomplish these objectives, I&M primarily employs risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

I&M utilizes power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. I&M utilizes interest rate derivative contracts in order to manage the interest rate exposure associated with the commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. I&M also utilizes derivative contracts to manage interest rate risk associated with debt financing. For disclosure purposes, these risks are grouped as "Interest Rate." The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors.

The following table represents the gross notional volume of outstanding derivative contracts:

Notional Volume of Derivative Instruments

Primary Risk Exposure	2023	2022	Unit of Measure
	(in millions)		
Commodity:			
Power	5.9	4.2	MWhs
Heating Oil and Gasoline	0.6	0.7	Gallons

Cash Flow Hedging Strategies

I&M utilizes cash flow hedges on certain derivative transactions for the purchase-and-sale of power ("Commodity") in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. I&M does not hedge all commodity price risk.

I&M utilizes a variety of interest rate derivative transactions in order to manage interest rate risk exposure. I&M also utilizes interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. I&M does not hedge all interest rate exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes and other assumptions. In order to determine the relevant fair values of the derivative instruments, I&M applies valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," I&M reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, I&M are required to post or receive cash collateral based on third-party contractual agreements and risk profiles. There was no cash collateral received from third-parties netted against short-term and long-term risk management assets for I&M as of December 31, 2023 and 2022. The amount of cash collateral paid to third-parties netted against short-term and long-term risk management liabilities was not material for I&M as of December 31, 2023 and 2022.
The following tables represent the gross fair value of I&M's derivative activity on the balance sheets.

	December 31, 2023		
Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Derivative Instrument Assets	$ 42.1	$ (2.5)	$ 39.6
Long-Term Portion of Derivative Instrument Assets	12.0	(0.2)	11.8
Derivative Instrument Liabilities	5.6	(3.6)	2.0
Long-Term Portion of Derivative Instrument Liabilities	0.2	(0.2)	—

Balance Sheet Location	December 31, 2022 Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Derivative Instrument Assets	$ 16.5	$ (1.1)	$ 15.4
Long-Term Portion of Derivative Instrument Assets	0.5	(0.3)	0.2
Derivative Instrument Liabilities	1.2	(1.2)	—
Long-Term Portion of Derivative Instrument Liabilities	0.3	(0.3)	—

(a) Derivative instruments within this category are disclosed as gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) All derivative contracts subject to a master netting arrangement or similar agreement are offset in the statement of financial position.

The table below presents the activity of derivative risk management contracts:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2023	2022
	(in millions)	
Operating Revenues	$ 24.5	$ 10.6
Operation Expenses	0.1	0.6
Maintenance Expenses	(0.1)	0.6
Other Regulatory Assets (a)	(3.1)	(0.8)
Other Regulatory Liabilities (a)	7.8	8.6
Total Gain (Loss) on Risk Management Contracts (b)	$ 29.2	$ 19.6

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the statements of income on an accrual basis.

The accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.
For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same line item on the statements of income as that of the associated risk being hedged. However, unrealized and some realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for "Regulated Operations."

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), I&M initially reports the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income on the balance sheets until the period the hedged item affects Net Income.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Operating Revenues or Operation Expenses on the statements of income or in Other Regulatory Assets or Other Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During the years ended 2023 and 2022, I&M did not apply cash flow hedging to outstanding power derivatives.

I&M reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income on the balance sheets into Interest on Long-term Debt on the statements of income in those periods in which hedged interest payments occur. During the year ended 2023, I&M applied cash flow hedging to outstanding interest rate derivatives. During the year ended 2022, I&M did not apply cash flow hedging to outstanding interest rate derivatives.

Cash flow hedges included in Accumulated Other Comprehensive Income on the balance sheets were:

Impact of Cash Flow Hedges on the Balance Sheets

December 31, 2023		December 31, 2022	
Interest Rate			
AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months
	(in millions)		
$ (5.5)	$ (0.4)	$ (5.1)	$ (0.6)

The actual amounts reclassified from Accumulated Other Comprehensive Income to Net Income can differ from the estimate above due to market price changes.

Credit Risk

Management mitigates credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. Management uses credit agency ratings and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. Some master agreements include margining, which requires a counterparty to post cash or letters of credit in the event exposure exceeds the established threshold. The
threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, master agreements allow for termination and liquidation of all positions in the event of a default including a failure or inability to post collateral when required.

Credit-Risk-Related Contingent Features

Credit Downgrade Triggers

A limited number of derivative contracts include collateral triggering events, which include a requirement to maintain certain credit ratings. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering events in contracts. I&M has not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. I&M had no derivative contracts with collateral triggering events in a net liability position as of December 31, 2023 and 2022.

Cross-Acceleration Triggers

Certain interest rate derivative contracts contain cross-acceleration provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-acceleration provisions could be triggered if there was a non-performance event by I&M under any of their outstanding debt of at least $50 million and the lender on that debt has accelerated the entire repayment obligation. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-acceleration provisions in contracts. I&M's derivative contracts with cross-acceleration provisions outstanding as of December 31, 2023 and 2022 were not material.

Cross-Default Triggers

In addition, a majority of non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third-party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. I&M had no derivative contracts with cross-default provisions outstanding as of December 31, 2023. I&M's derivative contracts with cross-default provisions outstanding as of December 31, 2022 were not material.

10. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of Long-term Debt are summarized in the following table:

	December 31,			
	2023		2022	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
	$ 3,358.4	$ 3,125.4	$ 3,095.5	$ 2,749.4

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF are recorded at fair value. See "Nuclear Trust Funds" section of Note 1 for additional information.

The following is a summary of nuclear trust fund investments:

	December 31,							
	2023				2022			
	Fair Value	Gross Unrealized Gains	Gross Unrealized Losses	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Gross Unrealized Losses	Other-Than-Temporary Impairments
	(in millions)							
Cash and Cash Equivalents	$ 16.8	$ —	$ —	$ —	$ 21.2	$ —	$ —	$ —
Fixed Income Securities:								
United States Government	1,273.0	28.6	(3.9)	(33.2)	1,123.8	11.8	(14.9)	(18.8)
Corporate Debt	132.1	4.8	(5.2)	(8.6)	61.6	0.7	(7.7)	(9.6)
State and Local Government	1.7	—	—	—	3.3	0.1	—	(0.1)
Subtotal Fixed Income Securities	1,406.8	33.4	(9.1)	(41.8)	1,188.7	12.6	(22.6)	(28.5)
Equity Securities - Domestic	2,436.6	1,869.5	(0.9)	—	2,131.3	1,483.7	(6.4)	—
Other Special Funds	$ 3,860.2	$ 1,902.9	$ (10.0)	$ (41.8)	$ 3,341.2	$ 1,496.3	$ (29.0)	$ (28.5)

The following table provides the securities activity within the decommissioning and SNF trusts:

	Years Ended December 31,	
	2023	2022
	(in millions)	
Proceeds from Investment Sales	$ 2,787.5	$ 2,713.6
Purchases of Investments	2,845.1	2,765.4
Gross Realized Gains on Investment Sales	99.0	52.4
Gross Realized Losses on Investment Sales	26.6	42.6

The base cost of fixed income securities was $1.4 billion and $1.2 billion as of December 31, 2023 and 2022, respectively. The base cost of equity securities was $568 million and $654 million as of December 31, 2023 and 2022, respectively. The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2023 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 359.6
After 1 year through 5 years	597.6
After 5 years through 10 years	180.7
After 10 years	268.9
Total	$ 1,406.8

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, I&M's financial assets and liabilities that were accounted for at fair value on a recurring basis. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

	December 31, 2023				
	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Derivative Instrument Assets					
Risk Management Commodity Contracts (b)	$ —	$ 37.4	$ 4.5	$ (2.3)	$ 39.6
Other Special Funds					
Cash and Cash Equivalents (c)	7.8	—	—	9.0	16.8
Fixed Income Securities:					
United States Government	—	1,273.0	—	—	1,273.0
Corporate Debt	—	132.1	—	—	132.1
State and Local Government	—	1.7	—	—	1.7
Subtotal Fixed Income Securities	—	1,406.8	—	—	1,406.8
Equity Securities - Domestic (a)	2,436.6	—	—	—	2,436.6
Total Other Special Funds	2,444.4	1,406.8	—	9.0	3,860.2
Total Assets	$ 2,444.4	$ 1,444.2	$ 4.5	$ 6.7	$ 3,899.8
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (b)	$ —	$ 3.7	$ 1.7	$ (3.4)	$ 2.0

	December 31, 2022				
	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Derivative Instrument Assets					
Risk Management Commodity Contracts (b)	$ —	$ 11.3	$ 5.3	$ (1.2)	$ 15.4
Other Special Funds					
Cash and Cash Equivalents (c)	11.3	—	—	9.9	21.2
Fixed Income Securities:					
United States Government	—	1,123.8	—	—	1,123.8
Corporate Debt	—	61.6	—	—	61.6
State and Local Government	—	3.3	—	—	3.3
Subtotal Fixed Income Securities	—	1,188.7	—	—	1,188.7
Equity Securities - Domestic (a)	2,131.3	—	—	—	2,131.3
Total Other Special Funds	2,142.6	1,188.7	—	9.9	3,341.2
Total Assets	$ 2,142.6	$ 1,200.0	$ 5.3	$ 8.7	$ 3,356.6
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (b)	$ —	$ 0.6	$ 0.7	$ (1.3)	$ —

(a) Amounts represent publicly-traded equity securities and equity-based mutual funds.
(b) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(c) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 1 amounts primarily represent investments in money market funds.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 2023	Derivative Instrument Assets (Liabilities)
	(in millions)
Balance as of December 31, 2022	$ 4.6
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	4.2
Settlements	(8.8)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	2.8
Balance as of December 31, 2023	$ 2.8

Year Ended December 31, 2022	Derivative Instrument Assets (Liabilities)
	(in millions)
Balance as of December 31, 2021	$ (0.7)
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	3.7
Settlements	(3.0)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	4.6
Balance as of December 31, 2022	$ 4.6

(a) Included in revenues on the statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These changes in fair value are recorded as regulatory liabilities for net gains and as regulatory assets for net losses or accounts payable.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

December 31, 2023

	Fair Value		Valuation	Significant Unobservable	Input/Range		Weighted
	Assets	Liabilities	Technique	Input (a)	Low	High	Average (b)
	(in millions)						
FTRs	$ 4.5	$ 1.7	Discounted Cash Flow	Forward Market Price	$ (1.48)	$ 8.40	$ 0.85

December 31, 2022

	Fair Value		Valuation	Significant Unobservable	Input/Range		Weighted
	Assets	Liabilities	Technique	Input (a)	Low	High	Average (b)
	(in millions)						
FTRs	$ 5.3	$ 0.7	Discounted Cash Flow	Forward Market Price	$ 0.16	$ 18.79	$ 1.23

(a) Represents market prices in dollars per MWh.
(b) The weighted-average is the product of the forward market price of the underlying commodity and volume weighted by term.

The following table provides the measurement uncertainty of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts, Natural Gas Contracts and FTRs as of December 31, 2023 and 2022:

Uncertainty of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

11. <u>INCOME TAXES</u>

Income Tax Expense (Benefit)

The details of I&M's Income Tax Expense (Benefit) as reported are as follows:

	Years Ended December 31,	
	2023	2022
	(in millions)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ 122.2	$ 55.0
Deferred	(63.4)	(52.3)
Total	58.8	2.7
Charged (Credited) to Nonoperating Income, Net:		
Current	(8.1)	(0.5)
Deferred	7.6	1.7
Total	(0.5)	1.2
Total Income Tax Expense	$ 58.3	$ 3.9

The following is a reconciliation of the difference between the amounts of federal income taxes computed by multiplying book income before income taxes by the federal statutory tax rate and the amount of income taxes reported:

	Years Ended December 31,			
	2023		2022	
	(in millions)			
Net Income	$	335.9	$	324.7
Income Tax Expense		58.3		3.9
Pretax Income	$	394.2	$	328.6
Income Taxes on Pretax Income at Statutory Rate (21%)	$	82.8	$	69.0
Increase (Decrease) in Income Taxes Resulting from the Following Items:				
Reversal of Origination Flow-Through		6.4		2.9
Investment Tax Credit Amortization		(1.6)		(3.1)
State and Local Income Taxes, Net		17.5		9.6
Removal Costs		(11.8)		(12.4)
AFUDC		(2.3)		(2.0)
Tax Reform Excess ADIT Reversal		(30.0)		(54.0)
Federal Return-to-Provision		(2.5)		(6.3)
Other		(0.2)		0.2
Income Tax Expense	$	58.3	$	3.9
Effective Income Tax Rate	14.8%		1.2%	

Net Deferred Tax Liability

The following table shows elements of I&M's net deferred tax assets (liabilities) and significant temporary differences:

	December 31,			
	2023		2022	
	(in millions)			
Deferred Tax Assets	$	1,014.0	$	933.5
Deferred Tax Liabilities		(2,183.9)		(2,090.7)
Net Deferred Tax Liabilities	$	(1,169.9)	$	(1,157.2)
Property Related Temporary Differences	$	(298.1)	$	(398.0)
Amounts Due to Customers for Future Federal Income Taxes		103.2		114.3
Deferred State Income Taxes		(238.1)		(227.0)
Accrued Nuclear Decommissioning		(776.5)		(632.7)
Regulatory Assets		32.3		(29.5)
Operating Lease Liability		10.8		13.6
All Other, Net		(3.5)		2.1
Net Deferred Tax Liabilities	$	(1,169.9)	$	(1,157.2)

Tax Credit Carryforward

As of December 31, 2023, I&M has federal tax credit carryforwards in the amount of $7 million. If these credits are not utilized, federal general business tax credits will expire in the years 2036 through 2041. I&M anticipates future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused.

Federal and State Income Tax Audit Status

The statute of limitations for the IRS to examine I&M and other AEP subsidiaries originally filed federal return has expired for tax years 2016 and earlier. I&M and other AEP subsidiaries have agreed to extend the statute of limitations on the 2017-2019 tax returns to October 31, 2024, to allow time for our refund claim to be approved by the Congressional Joint Committee on Taxation. The statute of limitations for the 2020 return is set to naturally expire in October 2024 as well.

The current IRS audit and associated refund claim evolved from a net operating loss carryback to 2015 that originated in the 2017 return. I&M and other AEP subsidiaries have received and agreed to immaterial IRS proposed adjustments on the 2017 tax return. The IRS exam is complete, and I&M and other AEP subsidiaries are currently waiting on the IRS to submit the refund claim to the Congressional Joint Committee on Taxation for resolution and final approval.

I&M and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns, and I&M and other AEP subsidiaries are currently under examination in several state and local jurisdictions. Generally, the statutes of limitations have expired for tax years prior to 2017. In addition, management is monitoring and continues to evaluate the potential impact of federal legislation and corresponding state conformity.

Federal Legislation

In August 2022, President Biden signed H.R. 5376 into law, commonly known as the Inflation Reduction Act of 2022 or IRA. Most notably this budget reconciliation legislation creates a 15% minimum tax on adjusted financial statement income (Corporate Alternative Minimum Tax or CAMT), extends and increases the value of PTCs and ITCs, adds a nuclear and clean hydrogen PTC, an energy storage ITC and allows the sale or transfer of tax credits to third parties for cash. As further significant guidance from Treasury and the IRS is expected on the tax provisions in the IRA, I&M and AEP subsidiaries will continue to monitor any issued guidance and evaluate the impact on future net income, cash flows and financial condition.
In December 2022, the IRS released Notice 2023-7, which provided initial CAMT guidance that I&M and other AEP subsidiaries can begin to rely on in 2023. Notably, the interim guidance in Notice 2023-7 confirmed the CAMT depreciation adjustment includes tax depreciation that is capitalized to inventory under §263A and recovered as part of cost of goods sold, providing significant relief to I&M and other AEP subsidiaries' potential CAMT exposure. In September 2023, the IRS released Notice 2023-64, which clarifies and supplements items in Notice 2023-7 and stated that additional guidance in the form of proposed regulations is expected. I&M and other AEP subsidiaries will continue to monitor and assess any additional guidance.

I&M and other AEP subsidiaries expect to be applicable corporations for purposes of the CAMT beginning in 2023. CAMT cash taxes are expected to be partially offset by regulatory recovery, the utilization of tax credits and additionally the cash inflow generated by the sale of tax credits. The sale of tax credits will be presented in the operating section of the statements of cash flows consistent with the presentation of cash taxes paid. I&M and other AEP subsidiaries will present the loss on sale of tax credits through income tax expense.

12. LEASES

I&M leases property, plant and equipment including, but not limited to, fleet, information technology and real estate leases. These leases require payments of non-lease components, including related property taxes, operating and maintenance costs. I&M does not separate non-lease components from associated lease components. Many of these leases have purchase or renewal options. Leases not renewed are often replaced by other leases. Options to renew or purchase a lease are included in the measurement of lease assets and liabilities if it is reasonably certain I&M will exercise the option.

Lease obligations are measured using the discount rate implicit in the lease when that rate is readily determinable. AEP has visibility into the rate implicit in the lease when assets are leased from selected financial institutions under master leasing agreements. When the implicit rate is not readily determinable, I&M measures its lease obligation using its estimated secured incremental borrowing rate. Incremental borrowing rates are comprised of an underlying risk-free rate and a secured credit spread relative to the lessee on a matched maturity basis.

Operating and Finance lease rental costs are generally charged to Operation Expense and Maintenance Expense in accordance with rate-making treatment for regulated operations. Lease costs associated with capital projects are included in Utility Plant on the balance sheets. For regulated operations with finance leases, a finance lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. The components of rental costs were as follows:

	Years Ended December 31,			
	2023		2022	
	(in millions)			
Operating Lease Cost	$	19.6	$	29.5
Finance Lease Cost:				
Amortization of Right-of-Use Assets		98.3		159.8
Interest on Lease Liabilities		9.0		6.2
Total Lease Rental Costs (a)	$	126.9	$	195.5

(a) Excludes variable and short-term lease costs, which were immaterial.

Supplemental information related to leases are shown in the tables below:

	December 31, 2023	December 31, 2022
	(in millions)	
Weighted-Average Remaining Lease Term (years):		
Operating Leases	4.53	5.79
Finance Leases	4.95	4.76
Weighted-Average Discount Rate:		
Operating Leases	3.89 %	3.62 %
Finance Leases	8.62 %	8.99 %

	Years Ended December 31, 2023	Years Ended December 31, 2022
	(in millions)	
Cash paid for amounts included in the measurement of lease liabilities:		
Operating Cash Flows from Operating Leases	$ 19.5	$ 29.7
Operating Cash Flows from Finance Leases	107.3	218.1
Non-cash Acquisitions Under Operating Leases	$ 7.9	$ 19.1

The following tables show property, plant and equipment under finance leases, operating leases and related obligations recorded on I&M's balance sheets:

	December 31, 2023	December 31, 2022
	(in millions)	
Property, Plant and Equipment Under Finance Leases:		
Utility Plant (a)	$ 31.5	$ 33.7
Nuclear Fuel Under Finance Leases (b)	153.8	179.1
Net Property, Plant and Equipment Under Finance Leases	$ 185.3	$ 212.8
Obligations Under Finance Leases:		
Noncurrent	$ 102.5	$ 121.2
Current	82.8	92.0
Total Obligations Under Finance Leases	$ 185.3	$ 213.2

(a) Includes $39 million and $35 million of accumulated provision for depreciation and amortization for the years ended December 31, 2023 and 2022, respectively.
(b) Includes $254 million and $221 million of accumulated provision for depreciation and amortization for the years ended December 31, 2023 and 2022, respectively.

	December 31, 2023	December 31, 2022
	(in millions)	
Property, Plant and Equipment Under Operating Leases:		
Utility Plant (a)	$ 37.9	$ 39.3
Nonutility Plant	32.6	33.2
Accumulated Provision for Depreciation and Amortization - Nonutility Plant	(16.6)	(8.2)
Net Property, Plant and Equipment Under Operating Leases	$ 53.9	$ 64.3
Obligations Under Operating Leases:		
Noncurrent	$ 37.7	$ 48.9
Current	16.8	16.0
Total Obligations Under Operating Leases	$ 54.5	$ 64.9

(a) Includes $26 million and $25 million of accumulated provision for depreciation and amortization for the years ended December 31, 2023 and 2022, respectively.

Future minimum lease payments consisted of the following as of December 31, 2023:

	Finance Leases	Operating Leases
	(in millions)	
2024	$ 100.7	$ 18.9
2025	61.0	10.6
2026	31.8	9.7
2027	8.3	8.9
2028	4.1	7.0
After 2028	7.2	4.8
Total Future Minimum Lease Payments	213.1	59.9
Less: Imputed Interest	27.8	5.4
Estimated Present Value of Future Minimum Lease Payments	$ 185.3	$ 54.5

Master Lease Agreements

I&M leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, I&M is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the amount guaranteed. As of December 31, 2023, the maximum potential loss by I&M for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term was $4 million.

Lessor Activity

I&M's lessor activity was immaterial as of and for the twelve months ended December 31, 2023 and December 31, 2022, respectively.

Nuclear Fuel Lease

In May 2019, I&M entered into a sale-and-leaseback transaction for $63 million with DCC Fuel XIII LLC (DCC XIII). DCC XIII is a single-lessee leasing arrangement with one asset and was formed for the sole purpose of acquiring, owning and leasing nuclear fuel to I&M. The lease has a variable rate and was a finance lease with a term of 54 months. I&M made payments on the lease monthly. I&M made the final payment in November 2023.

In November 2019, I&M entered into a sale-and-leaseback transaction for $61 million with DCC Fuel XIV LLC (DCC XIV). DCC XIV is a single-lessee leasing arrangement with one asset and was formed for the sole purpose of acquiring, owning and leasing nuclear fuel to I&M. The lease has a variable rate and is a finance lease with a term of 54 months. I&M makes payments on the lease monthly. Payments began in December 2019.

In October 2020, I&M entered into a sale-and-leaseback transaction for $70 million with DCC Fuel XV LLC (DCC XV). DCC XV is a single-lessee leasing arrangement with one asset and was formed for the sole purpose of acquiring, owning and leasing nuclear fuel to I&M. The lease has a variable rate and is a finance lease with a term of 54 months. I&M makes payments on the lease monthly. Payments began in November 2020.

In May 2021, I&M entered into a sale-and-leaseback transaction for $65 million with DCC Fuel XVI LLC (DCC XVI). DCC XVI is a single-lessee leasing arrangement with one asset and was formed for the sole purpose of acquiring, owning and leasing nuclear fuel to I&M. The lease has a fixed 0.93% rate and is a finance lease with a term of 54 months. I&M makes payments on the lease monthly. Payments began in June 2021.

In May 2022, I&M entered into a sale-and-leaseback transaction for $73 million with DCC Fuel XVII LLC (DCC XVII). DCC XVII is a single-lessee leasing arrangement with one asset and was formed for the sole purpose of acquiring, owning and leasing nuclear fuel to I&M. The lease has a fixed 3.44% rate and is a finance lease with a term of 54 months. I&M makes payments on the lease monthly. Payments began in June 2022.

In November 2022, I&M entered into a sale-and-leaseback transaction for $70 million with DCC Fuel XVIII LLC (DCC XVIII). DCC XVIII is a single-lessee leasing arrangement with one asset and was formed for the sole purpose of acquiring, owning and leasing nuclear fuel to I&M. The lease has a fixed 5.93% rate and is a finance lease with a term of 54 months. I&M makes payments on the lease monthly. Payments began in December 2022.

In November 2023, I&M entered into a sale-and-leaseback transaction for $70 million with DCC Fuel XIX LLC (DCC XIX). DCC XIX is a single-lessee leasing arrangement with one asset and was formed for the sole purpose of acquiring, owning and leasing nuclear fuel to I&M. The lease has a fixed 6.01% rate and is a finance lease with a term of 54 months. I&M makes payments on the lease monthly. Payments began in December 2023.

13. FINANCING ACTIVITIES

Long-term Debt

The following table details long-term debt outstanding:

	Maturity	Weighted-Average Interest Rate as of December 31, 2023	Interest Rate Ranges as of December 31, 2023	2022	Outstanding as of December 31, 2023	2022
Senior Unsecured Notes	2028-2053	4.52%	3.25%-6.05%	3.20%-6.05%	$ 2,875.0	$ 2,625.0
Pollution Control Bonds (a)	2025 (b)	2.49%	0.75%-3.05%	0.75%-3.05%	190.0	190.0
Spent Nuclear Fuel Obligation (c)					300.4	285.6
Other Long-term Debt	2025	6.00%	6.00%	6.00%	2.7	5.0
Unamortized Discount, Net					(9.7)	(10.1)
Total Long-term Debt Outstanding					$ 3,358.4	$ 3,095.5

(a) For certain series of Pollution Control Bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and insurance policies support certain series.
(b) Certain Pollution Control Bonds are subject to redemption earlier than the maturity date.
(c) Spent Nuclear Fuel Obligation consists of a liability along with accrued interest for disposal of SNF. See "Spent Nuclear Fuel Disposal" section of Note 6 for additional information.

As of December 31, 2023, outstanding long-term debt was payable as follows:

	(in millions)
2024	$ 2.3
2025	190.4
2026	—
2027	—
2028	350.0
After 2028	2,825.4
Principal Amount	3,368.1
Unamortized Discount	(9.7)
Total Long-term Debt	$ 3,358.4

Dividend Restrictions

I&M pays dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of I&M to transfer funds to Parent in the form of dividends.

All of the dividends declared by I&M are subject to a Federal Power Act requirement that prohibits the payment of dividends out of capital accounts in certain circumstances; payment of dividends is generally allowed out of retained earnings. The Federal Power Act also creates a reserve on earnings attributable to hydroelectric generation plants. Because of their ownership of such plants, this reserve applies to I&M.

I&M has credit agreements that contain covenants that limit their debt to capitalization ratio to 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

The most restrictive dividend limitation for I&M is through the credit agreements. As of December 31, 2023, the maximum amount of restricted net assets of I&M that may not be distributed to the Parent in the form of a loan, advance or dividend was $1.8 billion. The Federal Power Act restriction limits the ability of I&M to pay dividends out of retained earnings because of their ownership in hydroelectric generation. Additionally, the credit agreement covenant restrictions can limit the ability of I&M to pay dividends out of retained earnings. As of December 31, 2023, the amount of any such restrictions was $703 million.

Corporate Borrowing Program

I&M uses a corporate borrowing program to meet its short-term borrowing needs. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP Utility Money Pool operates in accordance with the terms and conditions of its agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of December 31, 2023 and 2022 are included in Notes Payable to Associated Companies on the balance sheets. I&M's money pool activity and corresponding authorized borrowing limits are described in the following table:

Years ended December 31,	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of December 31,	Authorized Short-term Borrowing Limit
				(in millions)		
2023	$ 475.3	$ 112.2	$ 149.0	$ 44.9	$ 63.3	$ 500.0
2022	318.6	—	105.2	—	249.9	500.0

The maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

Years ended December 31,	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rates for Funds Borrowed from the Utility Money Pool	Average Interest Rates for Funds Loaned to the Utility Money Pool
2023	5.77 %	4.66 %	5.81 %	5.33 %	5.14 %	5.65 %
2022	5.28 %	0.10 %	— %	— %	2.57 %	— %

Interest expense and interest income related to the Utility Money Pool financing relationship are included in Interest on Debt to Associated Companies and Interest and Dividend Income, respectively, on the statements of income. The interest expense related to the corporate borrowing programs were $3 million and $3 million for the years ended December 31, 2023 and 2022, respectively, and interest income related to the corporate borrowing programs were $2 million and $0 for the years ended December 31, 2023 and 2022, respectively.

Credit Facilities

See "Letters of Credit" section of Note 6 for additional information.

Securitized Accounts Receivables – AEP Credit

Under this sale of receivables arrangement, I&M sells, without recourse, certain of its customer accounts receivable and accrued utility revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for I&M's receivables. The costs of customer accounts receivable sold are reported in Other Deductions on I&M's statements of income. I&M manages and services its customer accounts receivable, which are sold to AEP Credit. AEP Credit securitizes the eligible receivables for I&M and retains the remainder.

The amount of accounts receivable and accrued utility revenues under the sale of receivables agreement as of December 31, 2023 and 2022 were $156 million and $167 million, respectively.

The fees paid to AEP Credit for customer accounts receivable sold were $16 million and $10 million for the years ended December 31, 2023 and 2022, respectively.

The proceeds on the sale of receivables to AEP Credit were $2.1 billion and $2 billion for the years ended December 31, 2023 and 2022, respectively.

14. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Income Taxes and Investment and Production Tax Credits" section of Note 1 in addition to "Corporate Borrowing Program" and "Securitized Accounts Receivables – AEP Credit" sections of Note 13.

Intercompany Billings

I&M performs certain utility services for each other when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

Power Coordination Agreement

Effective January 1, 2014, the FERC approved the PCA. Under the PCA, I&M, APCo, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective Off-system Sales and purchase activities.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo, PSO, SWEPCo and WPCo. Certain power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies' respective equity positions.

Joint License Agreement

AEPTCo entered into a 50-year joint license agreement with APCo, I&M, KPCo, OPCo and PSO, respectively, allowing either party to occupy the granting party's facilities or real property. After the expiration of these agreements, the term shall automatically renew for successive one-year terms unless either party provides notice. The joint license billing provides compensation to the granting party for the cost of carrying assets, including depreciation expense, property taxes, interest expense, return on equity and income taxes. AEPTCo recorded the costs related to these agreements in Operation Expense on the statements of income. I&M recorded income related to these agreements in Operating Revenues on the statements of income. The impact of the joint license agreement for the years ended December 31, 2023 and 2022 was not material.

Unit Power Agreements

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all of its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The UPA will continue in effect until the debt obligations of AEGCo secured by the Rockport Plant have been satisfied and discharged (currently expected to be December 2028). I&M's direct purchases from AEGCo were $181 million and $242 million for the years ended December 31, 2023 and 2022, respectively. These direct purchases are presented as Operation Expense on I&M's statements of income.

Sales and Purchases of Property

Certain AEP subsidiaries had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions and the net book value of all sales and purchases for the years ended December 31, 2023 and 2022 were not material. These sales and purchases are recorded in Utility Plant on the balance sheets.

Charitable Contributions to AEP Foundation

The American Electric Power Foundation is funded by American Electric Power and its utility operating units. The Foundation provides a permanent, ongoing resource for charitable initiatives and multi-year commitments in the communities served by AEP and initiatives outside of AEP's 11-state service area. In 2023, there were no charitable contributions made to the AEP Foundation. In 2022, I&M made an $11 million charitable contribution to the AEP Foundation recorded in Donations on the statements of income.

I&M Barging, Urea Transloading and Other Services

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NOx emissions at certain generation plants in the AEP System. I&M recorded revenues from barging, transloading and other services of $59 million and $54 million for the years ended December 31, 2023 and 2022, respectively, in Operating Revenues on the statements of income.

AEP Wind Holdings LLC PPAs

Prior to acquisition, Fowler Ridge 2 had PPAs with I&M and OPCo for a portion of their energy production. The I&M portion totaled $8 million and $12 million for the years ended December 31, 2023 and 2022, respectively, of purchased electricity.

Transmission Service Charges

The AEP East Companies are parties to the TA, which defines how transmission costs through the PJM OATT are allocated among the AEP East Companies on a 12-month average coincident peak basis. Additional costs for transmission services provided by AEPTCo and other transmission affiliates are billed to AEP East Companies through the PJM OATT. I&M recorded net transmission service charges of $226 million and $221 million, for the years ended December 31, 2023 and 2022, respectively, in Operation Expense on the statements of income.

Affiliated Revenues

The following table shows the revenues derived from direct sales to affiliates, auction sales to affiliates, net transmission agreement sales and other revenues for the years ended December 31, 2023 and 2022:

Related Party Revenues	Years Ended December 31, 2023	2022
	(in millions)	
Transmission Revenues	$ (11.1)	$ 7.7
Barging, Urea Transloading and Other Transportation Services	59.0	54.1
Other Revenues	9.9	7.8

15. PROPERTY, PLANT AND EQUIPMENT

Depreciation

I&M provides for depreciation of Utility Plant, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides total regulated annual composite depreciation rates by functional class:

Year	Nuclear	Steam	Other Generation	Hydro	Transmission	Distribution	General
				(in percentages)			
2023	3.9 %	7.4 %	5.1 %	3.6 %	2.5 %	2.9 %	9.1 %
2022	3.8 %	8.7 %	4.8 %	3.5 %	2.5 %	3.1 %	10.1 %

The composite depreciation rate generally includes a component for non-ARO removal costs, which is credited to accumulated depreciation on the balance sheets. Actual removal costs incurred are charged to accumulated depreciation.

Asset Retirement Obligations

As of December 31, 2023 and 2022, I&M's ARO liability for nuclear decommissioning of the Cook Plant was $2.11 billion and $2 billion, respectively. These liabilities are reflected in Asset Retirement Obligations on I&M's balance sheets. As of December 31, 2023 and 2022, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $3.51 billion and $3.01 billion, respectively. These assets are included in Spent Nuclear Fuel and Decommissioning Trusts on I&M's balance sheets.

The following is a reconciliation of the 2023 and 2022 aggregate carrying amounts of ARO:

Year	ARO at January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31,
			(in millions)			
2023	$ 2,028.1	$ 74.8	$ 4.8	$ (3.7)	$ 1.9	$ 2,105.9
2022	1,946.3	71.5	3.2	(0.6)	7.7	2,028.1

Jointly-owned Electric Facilities

I&M has electric facilities that are jointly-owned with affiliated companies. Using its own financing, I&M is obligated to pay its share of the costs of these jointly-owned facilities in the same proportion as its ownership interest. I&M's proportionate share of the operating costs associated with these facilities is included in its statements of income and the investments and accumulated depreciation are reflected in its balance sheets under Utility Plant as follows:

	Fuel Type	Percent of Ownership	Share as of December 31, 2023: Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
Rockport Generating Plant (a)(b)	Coal	50.0 %	$ 1,341.4	$ 7.9	$ 1,018.9

	Fuel Type	Percent of Ownership	Share as of December 31, 2022: Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
Rockport Generating Plant (a)(b)	Coal	50.0 %	$ 1,357.4	$ 9.2	$ 905.1

(a) Operated by I&M.
(b) AEGCo owns 50%.

16. REVENUE FROM CONTRACTS WITH CUSTOMERS

Disaggregated Revenues from Contracts with Customers

The table below represents revenues from contracts with customers, net of respective provisions for refund, by type of revenue for I&M.

	Years Ended December 31,	
	2023	2022
	(in millions)	
Retail Revenues:		
Residential Revenues	$ 827.5	$ 862.7
Commercial Revenues	560.4	562.0
Industrial Revenues	587.5	622.8
Other Retail Revenues	5.0	5.0
Total Retail Revenues	$ 1,980.4	$ 2,052.5
Wholesale Revenues:		
Generation Revenues	245.2	540.7
Transmission Revenues (a)	38.6	36.8
Total Wholesale Revenues	283.8	577.5
Other Revenues from Contracts with Customers (a)	27.6	43.9
Total Revenues from Contracts with Customers	2,291.8	2,673.9
Other Revenues:		
Alternative Revenues	(10.9)	10.0
Other Revenues	24.3	0.1
Total Other Revenues	13.4	10.1
Total Operating Revenues	$ 2,305.2	$ 2,684.0

(a) Amounts include affiliated and nonaffiliated revenues.

Performance Obligations

I&M has performance obligations as part of its normal course of business. A performance obligation is a promise to transfer a distinct good or service, or a series of distinct goods or services that are substantially the same and have the same pattern of transfer to a customer. The invoice practical expedient within the accounting guidance for "Revenue from Contracts with Customers" allows for the recognition of revenue from performance obligations in the amount of consideration to which there is a right to invoice the customer and when the amount for which there is a right to invoice corresponds directly to the value transferred to the customer.

The purpose of the invoice practical expedient is to depict an entity's measure of progress toward completion of the performance obligation within a contract and can only be applied to performance obligations that are satisfied over time and when the invoice is representative of services provided to date. I&M elected to apply the invoice practical expedient to recognize revenue for performance obligations satisfied over time as the invoices from the respective revenue streams are representative of services or goods provided to date to the customer. Performance obligations for I&M are summarized as follows:

Retail Revenues

I&M has performance obligations to generate, transmit and distribute electricity for sale to rate-regulated retail customers. The performance obligation to deliver electricity is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are variable as they are subject to the customer's usage requirements.

Rate-regulated retail customers typically have the right to discontinue receiving service at will, therefore these contracts between I&M and their customers for rate-regulated services are generally limited to the services requested and received to date for such arrangements. Retail customers are generally billed on a monthly basis, and payment is typically due within 15 to 20 days after the issuance of the invoice.

Wholesale Revenues - Generation

I&M has performance obligations to sell electricity to wholesale customers from generation assets in PJM. The performance obligation to deliver electricity from generation assets is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Wholesale generation revenues are variable as they are subject to the customer's usage requirements.

I&M also has performance obligations to stand ready in order to promote grid reliability. Stand ready services are sold into PJM's RPM capacity market. RPM entails a base auction and at least three incremental auctions for a specific PJM delivery year, with the incremental auctions spanning three years. The performance obligation to stand ready is satisfied over time and the consideration for which is variable until the occurrence of the final incremental auction, at which point the performance obligation becomes fixed.

Payments from the RTO for stand ready services are typically received within one week from the issuance of the invoice, which is typically issued weekly. Gross margin resulting from generation sales are primarily subject to margin sharing agreements with customers and vary by state, where the revenues are reflected gross in the disaggregated revenues table above.

Wholesale Revenues - Transmission

I&M has performance obligations to transmit electricity to wholesale customers through assets owned and operated. The performance obligation to provide transmission services in PJM is partially fixed for a period of one year or less. Payments from the RTO for transmission services are typically received within one week from the issuance of the invoice, which is issued weekly for PJM.

I&M collects revenues through transmission formula rates. The FERC-approved rates establish the annual transmission revenue requirement (ATRR) and transmission service rates for transmission owners. The formula rates establish rates for a one year period and also include a true-up calculation for the prior year's billings, allowing for over/under-recovery of the transmission owner's ATRR. The annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations," and are therefore presented as such in the disaggregated revenues table above.

The AEP East Companies are parties to the TA, which defines how transmission costs are allocated among the AEP East Companies on a 12-month average coincident peak basis. Affiliate revenues as a result of the TA are reflected as Transmission Revenues in the disaggregated revenues table above.

Fixed Performance Obligations

The following table represents the remaining fixed performance obligations satisfied over time as of December 31, 2023. Fixed performance obligations primarily include electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. I&M elected to apply the exemption to not disclose the value of unsatisfied performance obligations for
contracts with an original expected term of one year or less. Due to the annual establishment of revenue requirements, transmission revenues are excluded from the table below. I&M amounts shown in the table below include affiliated and nonaffiliated revenues.

2024	2025-2026	2027-2028	After 2028	Total
		(in millions)		
$ 4.4	$ 8.8	$ 8.8	$ 4.5	$ 26.5

Contract Assets and Liabilities

Contract assets are recognized when I&M has a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. I&M did not have any material contract assets as of December 31, 2023 and 2022.

When I&M receives consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheets in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. I&M's contract liabilities typically arise from services provided under joint use agreements for utility poles. I&M did not have any material contract liabilities as of December 31, 2023 and 2022.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on I&M's balance sheets within the Customer Accounts Receivable line item. I&M's balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Customer Accounts Receivable were not material as of December 31, 2023 and 2022. See "Securitized Accounts Receivable - AEP Credit" section of Note 13 for additional information.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable from Associated Companies on I&M's balance sheets were $44 million and $75 million, as of December 31, 2023 and 2022.

Contract Costs

Contract costs to obtain or fulfill a contract are accounted for under the guidance for "Other Assets and Deferred Costs" and presented as a single asset and are neither bifurcated nor reclassified between current assets and deferred debits on the balance sheets. Contract costs to acquire a contract are amortized in a manner consistent with the transfer of goods or services to the customer in Operation Expenses on the statements of income. I&M did not have material contract costs as of December 31, 2023 and 2022.

17. FERC ORDER NO. 784-A

On July 18, 2013, the FERC issued Order No. 784 that revised certain aspects of the accounting and reporting requirements under the Uniform System of Accounts related to energy storage accounts. Due to software limitations, the newly adopted and revised schedules in the FERC forms that would contain the energy storage accounts are not available to filers of the forms for use as of the effective date. Utilities with energy storage assets must use the existing schedules in the FERC Forms to report energy storage assets pending availability of the new and revised schedules. FERC directed filers to submit the requested energy storage information as part of pages 122-123.

The following table presents I&M's energy storage operations for small plants for the years ended December 31, 2023 and 2022, as required by FERC Order No. 784:

Project Name	Functional Classification	Project Location	Project Costs		Operation Expenses		Maintenance Expenses	
			Account	Amount	Account	Amount	Account	Amount (a)
					(dollars in millions)			
<u>Year Ended December 31, 2023</u>								
East Busco Station	Distribution	Churubusco, IN	363	$ 0.1	562	$ —	592	$ —
<u>Year Ended December 31, 2022</u>								
East Busco Station	Distribution	Churubusco, IN	363	$ 5.6	562	$ —	592	$ —

(a) This amount would have been recorded in Account 592.2 in accordance with FERC Order No. 784.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year				5,320,653	(6,572,799)		(1,252,146)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				(352,288)	1,602,303		1,250,015		
3	Preceding Quarter/Year to Date Changes in Fair Value				(285,858)			(285,858)		
4	Total (lines 2 and 3)				(638,146)	1,602,303		964,157	324,720,577	325,684,734
5	Balance of Account 219 at End of Preceding Quarter/Year				4,682,507	(4,970,496)		(287,989)		
6	Balance of Account 219 at Beginning of Current Year				4,682,507	(4,970,496)		(287,989)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				(889,320)	(353,077)		(1,242,397)		
8	Current Quarter/Year to Date Changes in Fair Value				941,879			941,879		
9	Total (lines 7 and 8)				52,559	(353,077)		(300,518)	335,873,067	335,572,549
10	Balance of Account 219 at End of Current Quarter/Year				4,735,066	(5,323,573)		(588,507)		

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	10,730,314,112	10,730,314,112					
4	Property Under Capital Leases	69,301,552	69,301,552					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	576,295,850	576,295,850					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	11,375,911,514	11,375,911,514					
9	Leased to Others							
10	Held for Future Use	1,320,294	1,320,294					
11	Construction Work in Progress	299,779,244	299,779,244					
12	Acquisition Adjustments							
13	Total Utility Plant (8 thru 12)	11,677,011,052	11,677,011,052					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	4,336,886,963	4,336,886,963					
15	Net Utility Plant (13 less 14)	7,340,124,089	7,340,124,089					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	4,086,974,174	4,086,974,174					
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	249,907,654	249,907,654					
22	Total in Service (18 thru 21)	4,336,881,828	4,336,881,828					
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation	5,135	5,135					
29	Amortization							
30	Total Held for Future Use (28 & 29)	5,135	5,135					
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment							
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,336,886,963	4,336,886,963					

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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication					
3	Nuclear Materials	(3,857,528)	151,583,720		[c]69,118,226	78,607,966
4	Allowance for Funds Used during Construction	3,818,635	2,446,424		[d]1,477,229	4,787,830
5	(Other Overhead Construction Costs, provide details in footnote)					
6	SUBTOTAL (Total 2 thru 5)	(38,893)				83,395,796
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)					
9	In Reactor (120.3)	1,645,219	71,353,724		[e]70,440,000	2,558,943
10	SUBTOTAL (Total 8 & 9)	1,645,219				2,558,943
11	Spent Nuclear Fuel (120.4)	[a]629,554,317	[b]62,041,731		[f]110,752,119	[h]580,843,929
12	Nuclear Fuel Under Capital Leases (120.6)	179,143,988	70,440,000	95,775,841		153,808,147
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	629,431,130		(63,638,193)	[g]110,752,119	582,317,204
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	180,873,501				238,289,611
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

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FOOTNOTE DATA

(a) Concept: SpentNuclearFuel
Includes 2022 costs in connection with nuclear leases: Finance charges - $3,353,036
(b) Concept: SpentNuclearFuelAdditions
Reclassification of $70,440,000 of nuclear fuel from owned to leased due to sale/leaseback with third party
(c) Concept: NuclearMaterialsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions
Placed nuclear fuel into reactor
(d) Concept: AllowanceForFundsConstructionNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions
Placed nuclear fuel into reactor
(e) Concept: NuclearFuelAssembliesInReactorOtherReductions
Reclassification of nuclear fuel from owned to leased due to sale/leaseback with third party - $70,440,000
(f) Concept: SpentNuclearFuelOtherReductions
Retirement of spent fuel
(g) Concept: AccumulatedProvisionForAmortizationOfNuclearFuelAssembliesOtherReductions
Retirement of spent fuel
(h) Concept: SpentNuclearFuel
Includes 2023 costs in connection with nuclear leases: Finance charges - $6,471,425

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization	117,425					117,425
3	(302) Franchise and Consents	19,866,098					19,866,098
4	(303) Miscellaneous Intangible Plant	347,296,364	35,927,370	38,358,673			344,865,061
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	367,279,887	35,927,370	38,358,673			364,848,584
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	7,407,266					7,407,266
9	(311) Structures and Improvements	109,625,689	23,985,498	589,583			133,021,604
10	(312) Boiler Plant Equipment	917,838,663	5,005,747	3,151,683			919,692,727
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	121,831,542	925,295	1,537,484			121,219,353
13	(315) Accessory Electric Equipment	63,319,328	14,820	3,085			63,331,063
14	(316) Misc. Power Plant Equipment	25,392,893	17,514				25,410,407
15	(317) Asset Retirement Costs for Steam Production	18,918,803	6,515,314				25,434,117
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,264,334,184	36,464,188	5,281,835			1,295,516,537
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights	1,879,589		1			1,879,588
19	(321) Structures and Improvements	461,818,704	13,570,746	2,383,509			473,005,941
20	(322) Reactor Plant Equipment	1,790,285,774	6,410,766	4,214,829			1,792,481,711
21	(323) Turbogenerator Units	717,544,503	3,910,330	1,114,745			720,340,088
22	(324) Accessory Electric Equipment	349,707,971	3,654,435	1,622,295			351,740,111
23	(325) Misc. Power Plant Equipment	292,172,235	3,063,601	1,499,781			293,736,055
24	(326) Asset Retirement Costs for Nuclear Production	496,814,452					496,814,452
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	4,110,223,228	30,609,878	10,835,160			4,129,997,946
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	706,302					706,302
28	(331) Structures and Improvements	6,038,325	679,351	14,070			6,703,606
29	(332) Reservoirs, Dams, and Waterways	25,772,096	18,952	6,979			25,784,069
30	(333) Water Wheels, Turbines, and Generators	16,616,873	69,701	30,650			16,655,924
31	(334) Accessory Electric Equipment	5,722,976	1,281,265	264,225			6,740,016
32	(335) Misc. Power Plant Equipment	2,842,619	12,379				2,854,998
33	(336) Roads, Railroads, and Bridges	853					853
34	(337) Asset Retirement Costs for Hydraulic Production	318,520					318,520
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	58,018,564	2,061,648	315,924			59,764,288
36	D. Other Production Plant						
37	(340) Land and Land Rights	5,311,684					5,311,684
38	(341) Structures and Improvements	734,924					734,924
39	(342) Fuel Holders, Products, and Accessories						

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
40	(343) Prime Movers						
41	(344) Generators	62,647,471	998,330				63,645,801
42	(345) Accessory Electric Equipment	5,116,394	(105,167)				5,011,227
43	(346) Misc. Power Plant Equipment	796,944	44,293				841,237
44	(347) Asset Retirement Costs for Other Production						
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	74,607,417	937,456				75,544,873
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	5,507,183,393	70,073,170	16,432,919			5,560,823,644
47	3. Transmission Plant						
48	(350) Land and Land Rights	80,126,762	2,283,106	2			82,409,866
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	81,317,493	13,037,090	798,665		19,297	93,575,215
50	(353) Station Equipment	869,625,927	41,903,703	10,815,521		(19,297)	900,694,812
51	(354) Towers and Fixtures	231,461,519	189,299	1,129,865			230,520,953
52	(355) Poles and Fixtures	246,283,527	16,941,965	4,828,370			258,397,122
53	(356) Overhead Conductors and Devices	315,493,916	6,905,355	3,311,840			319,087,431
54	(357) Underground Conduit	9,301,350	2,663,552				11,964,902
55	(358) Underground Conductors and Devices	8,281,750	1,289,559	52,202			9,519,107
56	(359) Roads and Trails	91,159					91,159
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,841,983,403	85,213,629	20,936,465			1,906,260,567
59	4. Distribution Plant						
60	(360) Land and Land Rights	32,110,017	1,973,976	2,199			34,081,794
61	(361) Structures and Improvements	55,170,936	15,855,397	326,974			70,699,359
62	(362) Station Equipment	537,312,684	60,244,028	5,481,104			592,075,608
63	(363) Energy Storage Equipment – Distribution	5,606,730		5,499,815			106,915
64	(364) Poles, Towers, and Fixtures	389,655,227	48,203,403	5,983,896			431,874,734
65	(365) Overhead Conductors and Devices	639,764,014	59,641,972	10,882,639			688,523,347
66	(366) Underground Conduit	184,903,947	17,642,744	134,828			202,411,863
67	(367) Underground Conductors and Devices	321,778,596	14,303,756	2,753,866			333,328,486
68	(368) Line Transformers	407,615,081	45,801,457	8,721,392			444,695,146
69	(369) Services	222,355,939	14,766,732	1,032,715			236,089,956
70	(370) Meters	161,951,901	27,380,570	27,925,138			161,407,333
71	(371) Installations on Customer Premises	31,271,593	2,532,837	957,295			32,847,135
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	32,046,702	1,552,579	7,839,872			25,759,409
74	(374) Asset Retirement Costs for Distribution Plant	2,968,296		2,968,296			
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,024,511,663	309,899,451	80,510,029			3,253,901,085
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
85	6. General Plant						
86	(389) Land and Land Rights	14,483,315	(4,972,192)				9,511,123
87	(390) Structures and Improvements	81,774,113	11,706,036	6,515,835			86,964,314
88	(391) Office Furniture and Equipment	5,703,382	1,155,209	89,953			6,768,638
89	(392) Transportation Equipment	72,626	(1,542)				71,084
90	(393) Stores Equipment	1,371,647	85,240				1,456,887
91	(394) Tools, Shop and Garage Equipment	19,185,176	3,085,616	561,303			21,709,489
92	(395) Laboratory Equipment	349,600	228,063				577,663

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
93	(396) Power Operated Equipment	543,715					543,715
94	(397) Communication Equipment	73,509,598	5,795,626	1,462,401			77,842,823
95	(398) Miscellaneous Equipment	13,098,542	923,448				14,021,990
96	SUBTOTAL (Enter Total of lines 86 thru 95)	210,091,714	18,005,504	8,629,492			219,467,726
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant	1,308,356					1,308,356
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	211,400,070	18,005,504	8,629,492			220,776,082
100	TOTAL (Accounts 101 and 106)	10,952,358,416	519,119,124	164,867,578			11,306,609,962
101	(102) Electric Plant Purchased (See Instr. 8)						
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	10,952,358,416	519,119,124	164,867,578			11,306,609,962

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ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
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47	TOTAL					

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ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Rockport Generating Plant Unit 1 (0111)	11/01/1984		1,034,109.00
3	Items under $250,000			280,262.00
21	Other Property:			
22	Items under $250,000			5,923.00
47	TOTAL			1,320,294

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	2023 Network Enhancements	1,540,937
2	ADMS Imp DSN DNEX-IM D	6,342,671
3	Ameriplex - Land purchase	1,266,256
4	Beckwith - Glenbrook	9,513,839
5	Business LAN Expansion	19,573,402
6	CIS-Common Deployment-IM D	5,506,320
7	Corp Prgrm Billing - I&M Trans	2,127,406
8	CRID Inverter Replacement U1	1,072,930
9	D/IM/Capital Blanket - IMPCo	1,569,302
10	Distributino CI	2,408,268
11	East Busco Battery Retirement	1,187,920
12	Ed-Ci-Impco-D Ast Imp	8,147,746
13	Ed-Ci-Impco-D Cust Serv	2,714,907
14	FW AMI VVO Circuits / Stations	4,327,826
15	GLBU 120 OpCo CI	1,457,648
16	I&M	1,263,074
17	I&M - Distribution	3,256,542
18	I&M IN Major Eq/Spare -Trans	1,868,457
19	I&M IN Major Eq/Spares- Distr	4,468,109
20	I&M CI	1,129,820
21	I&M D Supplemental Work	7,337,600
22	I&M Failure Distribution	1,250,017
23	I&M Grid Modernization CTS IN	1,856,350
24	I&M Grid Modernization DACR IN	2,215,015
25	I&M Major Eq/Spare -Trans	1,313,785
26	I&M T-OPCO	5,272,767
27	I&M Transmission Supplemental	2,462,821
28	I&M Transmission Work	7,725,906
29	I&M-T-BlnktProj Under $3M	5,510,868
30	IDS/Cyber & Upgrade Network	1,679,119
31	IM Trans Work	4,441,288
32	IM Trans Work Baseline	2,109,726
33	IM/IN Ameriplex Dline	1,623,493
34	IM/IN Ameriplex new station	5,852,471
35	IM/IN McGalliard Rd D Station	2,156,705
36	IMPCo Trans Pre Eng Parent	(4,371,620)
37	IMPCo Trans Pre Eng Parent	6,390,661
38	IMPCO-D Telecom	4,553,532
39	MI AMI VVO Circuits / Stations	1,230,274
40	Michigan Roadside Relocate	3,022,302
41	OPCO CI	1,025,449
42	OPCo D CI	2,579,127
43	OPCo D CI	2,547,619
44	OPCO Supplemental CI	1,313,324
45	Opco T CI	1,581,795
46	Opco T CI	1,969,220
47	OPCo T SUpplemental CI	1,273,120

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
48	Pleasant - Murray Line Reroute	1,598,712
49	REP IN 3PH OH Rebuild	1,284,626
50	REP IN 4KV Conversion	1,130,081
51	REP IN Circuit Ties	1,466,099
52	REP IN Cutouts, LAs	1,187,436
53	REP IN UG Cable Replacement	1,412,777
54	RK U0 CCR Compliance	(16,539,959)
55	RKP05CIIM Horiz RH ReplaceU1	3,000,507
56	RP-CI-IMPCo-G NMIB	19,217,935
57	RV Capital Station Opco	8,003,296
58	South Bend SC (New)	28,744,858
59	SPILLWAY CUT OFF WALL	8,313,957
60	SS-CI-IMPCo-D GEN PLT	8,338,814
61	Supplemental OPCo T work	3,031,592
62	T/IM/Capital Blanket - IMPCo	1,179,135
63	T/IM/Jefferson-Dumont Spacers	1,363,058
64	T/IM/Transmission Line Rebuild	5,378,584
65	Transformer #5/#9 purchase spa	1,705,023
66	WS-CI-IMPCo-G PPB	7,933,218
67	Other Minor Projects Under $1,000,000	55,363,381
43	Total	299,779,244

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ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	3,835,656,221	3,835,651,190	5,031	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	406,346,860	406,346,756	104	
4	(403.1) Depreciation Expense for Asset Retirement Costs	2,052,740	2,052,740		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):	23,416,131	[(a)]23,416,131		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	431,815,731	431,815,627	104	
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(126,525,055)	(126,525,055)		
13	Cost of Removal	(59,922,373)	[(b)](59,922,373)		
14	Salvage (Credit)	10,188,758	[(c)]10,188,758		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(176,258,670)	(176,258,670)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	(4,233,973)	[(d)](4,233,973)		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,086,979,309	4,086,974,174	5,135	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	757,583,245	757,583,245		
21	Nuclear Production	1,978,185,037	1,978,185,037		
22	Hydraulic Production-Conventional	38,852,807	38,852,807		
23	Hydraulic Production-Pumped Storage				
24	Other Production	16,692,625	16,692,625		
25	Transmission	478,428,490	478,423,355	5,135	
26	Distribution	775,717,245	775,717,245		
27	Regional Transmission and Market Operation				
28	General	41,519,860	41,519,860		
29	TOTAL (Enter Total of lines 20 thru 28)	4,086,979,309	4,086,974,174	5,135	

FOOTNOTE DATA

(a) Concept: OtherAccounts

Amortization of the Cook ARO	$ 23,757,616
Revised items due to IURC Final Order in I&M's Base Case Cause No. 44967	$ (442,916)
Amortize Indiana jurisdiction LCM deferred balances for carrying charges, depreciation, and property tax over a six year period as approved by the IURC in Cause No. 44182 LCM1 and amortize over recovery of all costs from Jul17-Jun18	$ (21,884)
Over/under recovery of the payments to the Michigan Energy Optimization Program administrator and associated carrying charges	$ 77,055
Amortization per MPSC Order in I&M Base Case No. U-18370	$ (167,049)
Record over/under recovery of the I&M South Bend Solar Project	$ (460,471)
ARO depr exp 1080013	$ 673,780
Total	$ 23,416,131

(b) Concept: CostOfRemovalOfPlant

Includes $(3,672,273) of removal cost in retirement work in progress (RWIP).

(c) Concept: SalvageValueOfRetiredPlant

Includes $3,855,056 of salvage in retirement work in progress (RWIP).

(d) Concept: OtherAdjustmentsToAccumulatedDepreciation

To amortize the deferred incremental depreciation expense for the MI portion of Rockport Unit 2 through December 2028 as a result of the pending purchase of Rockport Unit 2, aligning both the GAAP and regulatory depreciable lives through Dec. 2028.	$ (3,207,395)
Defer ARO Deprec & Accretion Exp	$ (1,026,578)
TOTAL	$ 4,233,973

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1	Blackhawk Coal Company, Inc.	09/01/1980						
2	Common Stock			25,324,001		(25,324,001)		
3	Cash Capital Contribution					2,086,934	2,086,934	
4	Equity in Earnings			(2,416,144)	329,210		(2,086,934)	
5	Investment in Subsidiary AOCI							
6	Subtotal							
42	Total Cost of Account 123.1 $		Total	22,907,857	329,210	(23,237,067)		

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	44,879,566	84,069,956	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	1,646,495	3,988,855	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	105,669,615	101,425,986	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	78,882,130	103,334,146	Electric
8	Transmission Plant (Estimated)	275,977	286,359	Electric
9	Distribution Plant (Estimated)	860,872	781,581	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	[(a)]590,627	[(b)]584,519	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	186,279,221	206,412,591	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	1,667,521	1,559,255	River Transport
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	1		
17				
18				
19				
20	TOTAL Materials and Supplies	234,472,803	296,030,657	

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FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesOther
Assigned to - Other includes customer account, administrative and general expenses.
(b) Concept: PlantMaterialsAndOperatingSuppliesOther
Assigned to - Other includes Customer Account, Administrative and General Expenses.

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Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year’s allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA’s sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA’s sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	563,158	25,386,062	115,572		80,899		80,899		2,110,034		2,950,562	25,386,062
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	958								91,296		92,254	
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9	Restricted Title IV SO2 Allowances												
10	[(a)] Other		(17,804,214)										(17,804,214)
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	3,814	44,369									3,814	44,369
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Consent Decree Surrenders	(1,464)		73,568								72,104	
23													
24													
25													
26													
27													
28	Total	(1,464)		73,568								72,104	
29	Balance-End of Year	561,766	7,537,479	42,004		80,899		80,899		2,201,330		2,966,898	7,537,479
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains		58										58
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year	357		357		357		357		56,556		57,984	
37	Add: Withheld by EPA									714		714	
38	Deduct: Returned by EPA												

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
39	Cost of Sales	357								357		714	
40	Balance-End of Year			357		357		357		56,913		57,984	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

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FOOTNOTE DATA

(a) Concept: AllowancesInventoryPurchasesTransfersDescription
As approved in the Final Order in Cause No. 45576 by the Indiana Utility Regulatory Commission, reclass excess SO2 allowances from allowance inventory #1581 to a Regulatory Asset #1823 of $17,804,214 to be amortized over 6 years from January 2023 through December 2028.

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Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	97,905	2,408	19,337								117,242	2,408
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	4,369		1,945								6,314	
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	1,860										1,860	
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Wolverine Power Supply Cooperative, Inc.												
23	Surrenders												
24	Consent Decree Surrenders												
25	Unknown												
26	Other												
27													
28	Total												
29	Balance-End of Year	100,414	2,408	21,282								121,696	2,408
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

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Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
20	TOTAL					

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UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of COmmission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	AD1-100	2,058	186	2,129	186
3	AE1-070	33,304	186	31,712	186
4	AE1-163	6	186		
5	AF1-071	2,671	186	2,671	186
6	AF1-084	6,703	186	6,888	186
7	AF1-088	4,508	186	4,508	186
8	AF1-091	3,457	186	5,965	186
9	AF1-092	1,140	186	1,274	186
10	AF1-141	5,504	186	6,927	186
11	AF1-148	3,123	186	3,123	186
12	AF1-161	1,213	186	956	186
13	AF1-202	20,333	186	22,226	186
14	AF1-204	159	186	159	186
15	AF1-207	6,363	186	6,155	186
16	AF1-215	13,309	186	8,678	186
17	AF1-223	2,076	186	2,076	186
18	AF1-268	2,010	186	2,010	186
19	AF1-322	4,566	186	4,359	186
20	AF2-094	1,554	186	1,554	186
21	AF2-125	606	186		
22	AF2-132	388	186	388	186
23	AF2-133	62	186	62	186
24	AF2-134	4,038	186	4,038	186
25	AF2-162	36	186	36	186
26	AF2-173	8,754	186	8,991	186
27	AF2-177	1,095	186	1,095	186
28	AF2-204	3,215	186	2,909	186
29	AF2-205	5,154	186	5,154	186
30	AF2-224	2,392	186	2,392	186
31	AF2-370	1,003	186		
32	AF2-389	2,280	186	1,874	186
33	AG1-017	738	186	747	186
34	AG1-047	738	186	738	186
35	AG1-222	1,634	186		
36	AG1-224	1,661	186		
37	AG1-225	1,362	186		
38	AG1-232	2,039	186	1,651	186
39	AG1-302	1,245	186	349	186
40	AG1-324	5,251	186	6,388	186
41	AG1-349	1,992	186	1,943	186
42	AG1-367	536	186	528	186
43	AG1-368	831	186	918	186
44	AG1-375	536	186		
45	AG1-417	363	186	363	186

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
46	AG1-424	2,041	186	1,219	186
47	AG1-433	676	186	676	186
48	AG1-436	429	186	164	186
49	AG1-447	429	186	429	186
50	AG1-453	170	186	953	186
51	AG1-454	8,945	186	9,017	186
52	AG2-242	(1,302)	186		
53	AH1-084	196	186	196	186
54	AH1-085	196	186	196	186
55	AH1-549	(8,786)	186		
56	AI2-144	230	186		
57	J1180 MISO	41,466	186	40,691	186
58	J793	1,105	186		
59	PJM #AF1-046	4,405	186	5,425	186
60	PJM - # AE1-17	596	186	10,169	186
61	PJM - # AE2-32	676	186	1,413	186
62	PJM - #AC2-090	941	186	352	186
63	PJM - #AC2-157	13,827	186	16,465	186
64	PJM - #AD1-043	1,877	186	593	186
65	PJM - #AD1-128	297	186	143	186
66	PJM - #AD2-020	2,666	186	2,812	186
67	PJM - #AD2-071	1,485	186	1,485	186
68	PJM - #AE1-207	2,513	186	2,513	186
69	PJM - #AE1-208	2,768	186	2,768	186
70	PJM - #AE1-209	3,380	186	4,010	186
71	PJM - #AE1-210	165	186	880	186
72	PJM - #AE2-089	2,656	186	2,656	186
73	PJM - #AE2-130	17,211	186	20,337	186
74	PJM - #AE2-154			499	186
75	PJM - #AE2-169	937	186	937	186
76	PJM - #AE2-172	1,812	186	1,812	186
77	PJM - #AE2-219	1,722	186	2,893	186
78	PJM - #AE2-220	11,942	186	13,114	186
79	PJM - #AE2-234	4,984	186	5,456	186
80	PJM - #AE2-236	5,149	186	7,165	186
81	PJM - #AE2-276	93	186	93	186
82	PJM - #AE2-323	2,287	186	2,287	186
83	PJM - #AF1-118	2,465	186	2,465	186
84	PJM - #AF1-119	1,344	186	1,921	186
85	PJM - #AF1-158	7,226	186	7,597	186
86	PJM - #AF1-221	20,927	186	17,168	186
20	Total	324,152		342,903	
21	**Generation Studies**				
22	Cook Study AC2-140			671	107
39	Total			671	
40	Grand Total	324,152		343,574	

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Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	2022 PJM Transmission True-up	4,693,088	6,245,437	447, 456	5,295,224	5,643,301
2	City of Fort Wayne Settlement, IURC Cause Order #44075, Amortization Period: 03/2013 - 04/2025	2,151,102		588	914,591	1,236,511
3	Cook Life Cycle Management Program - Indiana Portion, IIURC Cause Order #44182	21,885	133,896	403	155,781	
4	Cook Life Cycle Management Program - Michigan Portion, MPSC Case U-17026	12,073,435	459,678	403, 182, 421, 408	1,472,991	11,060,122
5	Cook Plant Refueling	81,218,279	53,470,897	519, 520, 523, 524, 528, 529, 530, 531, 532	79,030,258	55,658,918
6	Cook Plant Water Study Cost	8,677,098	1	524	713,793	7,963,306
7	Cook Turbine Replacement CC - Indiana, IURC Cause Order #44075	9,039,287	314,629	182, 421	915,918	8,437,998
8	Cook Unit 2 Baffle Bolts, IURC Cause Order #44075, Amortization Period: 03/2013 - 02/2038	4,549,033		530	299,936	4,249,097
9	Cook Uprate Project	25,321,182		524	2,417,536	22,903,646
10	COVID-19 Deferred Bad Debt Expense	1,039,403		426	788,460	250,943
11	Deferred Depreciation Rockport Unit 2	19,244,368		108	3,207,395	16,036,973
12	Deferred Storm Expense	24,992,891	14,708,408	593	6,631,832	33,069,467
13	DSM Energy Optimization Program - Michigan	416,811	5,364,840	908, 421	509,955	5,271,696
14	IN Tax Rider Under Recovery	7,291,242	1,933,192	407	8,440,085	784,349
15	Indiana DSM Program, IURC Cause order #43287, IURC Cause order #44182	10,286,335	3,120,211	908	13,406,546	
16	Indiana Environmental Compliance Rider	6,607,313	2,860,539	502	1,333,265	8,134,587
17	Indiana Plugged In Rebate Deferral	75,126	54,378	182, 431	2,577	126,927
18	Indiana RAR Over Recovery		182,114			182,114
19	Michigan Dry Cask Storage Deferral	284	159	182, 431	62	381
20	Michigan Home Energy Management and Work Energy Management Programs	734,699	87,642	908	18,515	803,826
21	Michigan Plugged In Rebate Deferral	26,736	55,147	182, 431	1,144	80,739
22	Michigan Under Recovered Fuel Interest	199,161	786,689	431	290,055	695,795
23	Nuclear Decommissioning Study Expense	106,495	35,830	923.00	92,700	49,625
24	Rate Case Expenses	1,830,071	841,939	928	1,008,105	1,663,905
25	River Transportation Selling Price Variance	5,229,183	14,402,971	186, 417	13,667,276	5,964,878
26	Rockport DSI Project - Indiana 20% Non Federal Mandate Rider, IURC Cause Order #44331	6,345,903	152,604	403, 500, 502, 421	1,436,756	5,061,751
27	SFAS 106 Medicare Subsidy, Amortization Period: 01/2013 - 12/2024	2,040,270		926	1,020,135	1,020,135
28	SFAS 109 Deferred FIT	154,413,009	291,755,724	190, 236, 254, 255	278,547,554	167,621,179
29	SFAS 109 Deferred SIT	226,406,821	66,026,991	283	56,329,230	236,104,582
30	SFAS 112 Post Employment Benefits	7,732,174	251,035	228	954,794	7,028,415
31	SFAS 158 Employer Accounting	26,942,685	71,463,289	129, 190, 219, 228	73,081,982	25,323,992
32	SNF Incremental Costs	2,143				2,143
33	Unrealized Loss on Forward Commitments Regulated Assets/Liabilities		3,111,269	175, 244, 254	5,527	3,105,742
34	Unrecovered Fuel Costs - Indiana	38,071,311	33,012,056	440, 442, 444	71,083,367	
35	Unrecovered Fuel Costs - Michigan	8,805,003	12,246,543	440, 442, 444	6,921,473	14,130,073
36	IN Deferred Renewable Development		210,920			210,920
37	Excess SO2 Allowance Inventory		15,084,126	509	247,281	14,836,845
44	TOTAL	696,583,826	598,373,154		630,242,099	664,714,880

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS: Credits Account Charged (d)	CREDITS: Credits Amount (e)	Balance at End of Year (f)
1	Property Taxes	53,240,703	74,473,082	107/236/408	75,781,658	51,932,127
2	Property Taxes - Capital Leases	62,738	1,168,043	408	1,149,638	81,143
3	Agency Fees, Factored Accts Rec	3,337,127	42,249,403	142/173/184/ 426	42,458,336	3,128,194
4	River Transport Division	6,269,869	62,233,828	106/121/122/142/143/144/152/156/163/165/182/232/236/242/408/417/421/426/430	64,092,685	4,411,012
5	Estimated Barging Bills					
6	Unamortized Credit Line Fees	902,564	210,798	431	500,674	612,688
7	Defd Non-taxable Leased Assets	63,868	1,358,492	142/143/184	917,807	504,553
8	Minor Items	3,569				3,569
9	Transource OU Acctg for Def Asset	95,411	93,923	565	137,097	52,237
10	Long Term Assoc	7,350,122	41,767,130	186/456/565	14,287,893	34,829,359
11	Unidentified Cash Receipts	93,458	7,487	131/146/253	3,030	97,915
12	Railroad Cars Subleased	2,399	27,665	151/236	30,064	
13	Deferred Expenses	3,652,555			3,652,555	
47	Miscellaneous Work in Progress	3,236,988				3,693,963
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	78,311,371				99,346,760

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	ACCRD BOOK ARO EXPENSE - SFAS 143	425,891,765	418,887,358
3	Reg Liability - SFAS 143 - ARO	276,893,330	342,507,010
4	CAPITALIZED INTEREST	38,767,504	37,492,971
5	BOOK OPERATING LEASE - LIAB	13,636,399	10,843,432
6	SI-AMORT INT PRE 4 7 83 DISP	30,407,746	29,068,799
7	Other	(24,037,408)	15,553,584
8	TOTAL Electric (Enter Total of lines 2 thru 7)	761,559,336	854,353,154
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)	171,934,383	[a]159,661,115
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	933,493,719	1,014,014,269

Notes

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Line 17 Other - Detail		Balance at Beginning of Year		Balance at End of Year
Acc Def Income Taxes - Federal - Hdg-CF-Int Rate		1,321,271		1,415,127
Non Utility Items - 190.2		6,338,637		3,493,009
SFAS 109-Regulatory Assets - 190.3 & 190.4		165,519,193		156,011,667
SFAS 133		—		—
Accu Def Income Taxes Pension-OCI		(1,244,717)		(1,258,688)
Total	$	171,934,384	$	159,661,115

Line 18

Reconciliation of details applicable to Account 190, Line 18, Columns (b) and (c) :

Balance at Beginning of Year	$	933,493,719
(Less) Amounts Debited to:		
(a) Account 410.1		(70,579,529)
(b) Account 410.2		(11,768,587)
(c) 1823/254/219/129/427		(60,310,634)
(Plus) Amounts Credited to:		
(a) Account 411.1		166,264,307
(b) Account 411.2		5,309,628
(c) 1823/254/219/129/427		51,605,365
Balance at End of Year	$	1,014,014,269

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2		2,500,000			1,400,000	56,583,866				
5	Total	2,500,000			1,400,000	56,583,866				
6	Preferred Stock (Account 204)									
7										
8										
9										
10	Total									
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2024-04-09	Year/Period of Report End of: 2023/ Q4

Other Paid-in Capital

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

a. Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
b. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
c. Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
d. Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	972,666,991
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	972,666,991
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	120,554
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	120,554
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	11,849,054
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	8,774,270
16	Ending Balance Amount	20,623,324
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	993,410,869

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CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	127

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number.
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number.
5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a)principal advanced during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)
1	Bonds (Account 221)										
2	None										
3	Subtotal										
4	Reacquired Bonds (Account 222)										
5											
6											
7											
8	Subtotal										
9	Advances from Associated Companies (Account 223)										
10	None										
11	Subtotal										
12	Other Long Term Debt (Account 224)										
13	[(a)] Spent Nuclear Fuel Disposal Costs Prior To April 7, 1983 - Basic Fee Assessment & Interest		285,582,850								
14	Series 2002 A - 2.75% Fixed Rate		50,000,000		296,785			08/01/1985	06/01/2025	08/01/1985	06/01/2025
15							325,000				
16							136,351				
17					444,593			06/01/2007	06/01/2025	06/01/2007	06/01/2025
18					386,217			12/01/2017	06/01/2025	12/01/2017	06/01/2025
19					74,250					06/01/2020	05/31/2021
20					74,250					06/01/2021	05/31/2022
21					74,250					06/01/2022	05/31/2023
22	[(b)] Series 2009 A - 3.05% Fixed Rate		50,000,000		353,976			03/26/2009	06/01/2025	04/01/2009	05/31/2014
23					249,468					06/01/2014	05/31/2018
24					354,263			06/01/2018	06/01/2025	06/01/2018	06/01/2025
25	[(c)] Series 2009 B - 3.05% Fixed Rate		50,000,000		353,976			03/26/2009	06/01/2025	04/01/2009	05/31/2014
26					249,469					06/01/2014	05/30/2018
27					354,262			06/01/2018	06/01/2025	06/01/2018	06/01/2025
28	[(d)] Series D -0.750% Fixed Rate		40,000,000		632,137			06/01/2021	04/01/2025	06/01/2021	04/01/2025
29					40,998					06/01/2021	04/01/2025
30	Series L - 3.75% Fixed Rate		300,000,000		3,139,683		2,088,000	06/29/2017	07/01/2047	06/29/2017	07/01/2047
31	Series K - 4.55% Fixed Rate		400,000,000		4,036,755		1,372,000	03/03/2016	03/15/2046	03/03/2016	03/15/2046
32	Series H - 6.05% Fixed Rate		400,000,000		3,815,383		2,272,000	11/14/2006	03/15/2037	11/14/2006	03/15/2037
33	Amortization of Cash Flow Hedges on 6.05% SUN									11/14/2006	02/28/2037
34	Series J - 3.20% Fixed Rate		250,000,000		1,969,707		402,500	03/18/2013	03/15/2023	03/18/2013	03/15/2023
35	Series O-3.250% Fixed Rate		450,000,000		4,825,845		3,501,000	04/29/2021	05/01/2051	04/29/2021	05/01/2051
36	[(e)] Fort Wayne Settlement		21,802,388					03/01/2010	02/28/2025	03/01/2010	02/28/2025
37	Series P - 5.63% Fixed Rate		500,000,000		5,215,340		155,000	03/21/2023	04/01/2053	03/21/2023	04/01/2053
38	Amortization of settle hedge at debt issuance on 5.63% SUN									03/21/2023	02/28/2033
39	Amortization of Interest Rate Swap on 3.20% SUN									03/18/2013	03/15/2023
40	Series M - 3.85% Fixed Rate		350,000,000		2,865,394		1,102,500	05/02/2018	05/15/2028	05/02/2018	05/15/2028
41	Series N - 4.25% Fixed Rate Per IURC Authority Cause #45057		475,000,000		4,926,878		2,717,000	08/08/2018	08/15/2048	08/08/2018	08/15/2048
30	Subtotal		3,622,385,238		34,733,879		14,071,351				
33	TOTAL		3,622,385,238								

Line No.	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13	300,381,960	
14	50,000,000	1,375,000
15		
16		
17		
18		
19		
20		
21		
22	50,000,000	1,525,000
23		
24		
25	50,000,000	1,525,000
26		
27		
28	40,000,000	300,000
29		
30	300,000,000	11,250,000
31	400,000,000	18,200,000
32	400,000,000	24,200,000
33		420,240
34		1,644,444
35	450,000,000	14,625,000
36	2,720,498	
37	500,000,000	21,718,750
38		109,396
39		334,685
40	350,000,000	13,475,000
41	475,000,000	20,187,500
30	3,368,102,458	130,890,015
33	3,368,102,458	130,890,015

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: ClassAndSeriesOfObligationCouponRateDescription

The Federal government is responsible for permanent spent nuclear fuel disposal and assess fees to nuclear plant owners for spent nuclear fuel disposal. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program and has recorded this future payment as long term debt...

(b) Concept: ClassAndSeriesOfObligationCouponRateDescription

The $50 million 6.25% City of Rockport Series 2009B PCRB was issued 3/26/2009 with a maturity date of 6/1/2025 and a mandatory tender date of 6/2/2014. On the 6/2/2014 put date, the PCRB was converted to 1.75% with a mandatory tender date of 6/1/2018. On the 6/1/2018 put date, the PCRB was converted to 3.05% with a maturity date of 6/1/2025. Issuance expenses totaling $354,262 will be amortized through 6/1/2025.

(c) Concept: ClassAndSeriesOfObligationCouponRateDescription

The $50 million 6.25% City of Rockport Series 2009A PCRB was issued 3/26/2009 with a maturity date of 6/1/2025 and a mandatory tender date of 6/2/2014. On the 6/2/2014 put date, the PCRB was converted to 1.75% with a mandatory tender date of 6/1/2018. On the 6/1/2018 put date, the PCRB was converted to 3.05% with a maturity date of 6/1/2025. Issuance expenses totaling $354,263 will be amortized through 6/1/2025.

(d) Concept: ClassAndSeriesOfObligationCouponRateDescription

The $40 million City of Rockport Series D,PCRB was issued on June , 2021. The interest rate is variable with the maturity date of April 1, 2025..The $40M million was reissued on December 14 ,2021 and the interest rate converted to 0.75% with the maturity date of April 1,2025

(e) Concept: ClassAndSeriesOfObligationCouponRateDescription

On August 10, 2011, the Indiana Utility Regulatory Commission issued a Final Order in Cause No. 43980 approving an agreement between Indiana Michigan Power Company and the City of Fort Wayne, Indiana to settle all disputes and other matters between them relating to the 1974 Lease Agreement pursuant to which I&M leased certain electric property from the city. The agreement required I&M to purchase the leased property and settle certain claims asserted by the City of Fort Wayne. Pursuant to the agreement, I&M paid the city $5 million within thirty days of the effective date of the final order. Further, the agreement provided that I&M pay the city a total of $34.2 million, including interest, over 15 years (March 2010 to February 2025), and that the City of Fort Wayne recognize I&M as the exclusive electricity provider in the Fort Wayne area. Interest on this liability is recorded in account 431.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	335,873,067
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	[a]374,522,605
28	Show Computation of Tax:	
29		
30		
31		
32		
33		
34		
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36		
37		
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43		
44		

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: FederalTaxNetIncome

FOOTNOTE DATA

Schedule Page: 261 Line No.: 28 Column: b A

Description	Amount('000)
Net Income for the Year per Page 117	$335,873
Federal Income Taxes	$36,082
State Income Taxes	$22,176
Pre-Tax Book Income	$394,131
Increase (Decrease) in Taxable Income resulting from:	
Excess tax vs book depreciation	$35,051
Asset Retirement Obligation	$1,353
Afudc / interest capitalized	$(8,539)
Percent repair allowance	$(145,033)
Removal costs	$(56,386)
Accelerated amortization	$13,409
Revenue refunds	$4,937
Deferred Fuel Costs	$32,746
Equity in earnings of subsidiaries	$(329)
Book accruals	$(20,723)
Book deferrals	$1,235
Other miscellaneous	$(19,533)
OPEB - Others miscellaneous	$(3,187.00)
Permanent Schedule M's	$1,676
Tax accruals	$157
Tax deferrals	$18,038
Nuclear fuel adjustments	$96,614
Nuclear fuel disposal costs	$(14,799)
Book deferred nuclear costs	$25,559
Emission Allowances	$17,849
Taxable Income before State Taxes	$374,226
State & Local Current Tax	$15,658
Federal Taxable Income	$358,568
Computation of Tax:	
FIT on Current Year Taxable Income	$75,299
Tax Credits	$(8,477)
Solar Investment Tax Credits	$—
NOL Reclass	$—
R&D Credit	$—
Estimated Tax Currently Payable (b)	$66,822
Adjustments of Prior Year's Accruals	$26,308
Tax Expense for R/C of Net Operating Loss (Prior Yr)	
Estimated Current Federal Income Taxes	$93,130

Represents the allocation of estimated current year net operating tax income of American Electric Power Company, Inc.

FOOTNOTE DATA

Instruction 2.
* The tax computation above represents an estimate of the Company's allocated portion of the System consolidated Federal Income Tax.
The computation of actual 2023 System Federal income taxes will not be available until the consolidated Federal Income tax return is filed by October 2024.The actual allocation of the System consolidated Federal income tax to the members of the consolidated group will not be available until after the Consolidated Federal Income Tax Return is filed."

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR	
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)
1	Federal Income	Federal Tax			3,394,397	0	84,535,717	84,145,226		3,784,888	
2	**Subtotal Federal Tax**				3,394,397	0	84,535,717	84,145,226	0	3,784,888	0
3	State Tax	State Tax	IL	2016	0	0				0	
4	State Tax	State Tax	IL	2017	(198,385)					(198,385)	0
5	State Tax	State Tax	IL	2018	375,107					375,107	0
6	State Tax	State Tax	IL	2019	667,976					667,976	0
7	State Tax	State Tax	IL	2020	(508,605)					(508,605)	0
8	State Tax	State Tax	IL	2021	(565,482)					(565,482)	
9	State Tax	State Tax	IL	2022	126,194		0			126,194	0
10	State Tax	State Tax	IL	2023			362,139			362,139	
11	State Tax	State Tax	IN	2015	(30,176)					(30,176)	0
12	State Tax	State Tax	IN	2017	(4,389,858)					(4,389,858)	0
13	State Tax	State Tax	IN	2018	7,980,470					7,980,470	0
14	State Tax	State Tax	IN	2019	2,361,490					2,361,490	0
15	State Tax	State Tax	IN	2020	(8,250,230)					(8,250,230)	0
16	State Tax	State Tax	IN	2021	(7,254,948)					(7,254,948)	0
17	State Tax	State Tax	IN	2022	6,269,413			3,276,855		2,992,558	0
18	State Tax	State Tax	IN	2023			15,941,805	12,742,000		3,199,805	
19	State Tax	State Tax	KY	2017	(147,238)					(147,238)	0
20	State Tax	State Tax	KY	2018	87,492					87,492	0
21	State Tax	State Tax	KY	2019	36,699					36,699	0
22	State Tax	State Tax	KY	2020	(99,872)					(99,872)	0
23	State Tax	State Tax	KY	2021	(22,885)					(22,885)	0
24	State Tax	State Tax	KY	2022	98,438					98,438	0
25	State Tax	State Tax	KY	2023			217,801			217,801	
26	State Tax	State Tax	MI	2017	(1,008,265)					(1,008,265)	0
27	State Tax	State Tax	MI	2018	1,961,572					1,961,572	0
28	State Tax	State Tax	MI	2019	1,708,540					1,708,540	0
29	State Tax	State Tax	MI	2020	(2,689,462)					(2,689,462)	0
30	State Tax	State Tax	MI	2021	(2,464,687)					(2,464,687)	0
31	State Tax	State Tax	MI	2022	2,097,481					2,097,481	0
32	State Tax	State Tax	MI	2023			3,949,221			3,949,221	
33	State Tax	State Tax	MO	2017	(1,164)					(1,164)	0
34	State Tax	State Tax	MO	2018	255					255	0
35	State Tax	State Tax	MO	2019	(342)					(342)	0
36	State Tax	State Tax	MO	2020	161					161	0
37	State Tax	State Tax	MO	2021	3					3	0
38	State Tax	State Tax	MO	2022	12,057					12,057	0
39	State Tax	State Tax	MO	2023			128	1,000		(872)	
40	State Tax	State Tax	MULTI	2015	(1,561,261)					(1,561,261)	0
41	State Tax	State Tax	MULTI	2019	7,946,458					7,946,458	0
42	State Tax	State Tax	MULTI	2021	1,135					1,135	0
43	State Tax	State Tax	OH	2023			245			245	0
44	State Tax	State Tax	UT	2020	148,135					148,135	0
45	State Tax	State Tax	UT	2021	(148,135)					(148,135)	0
46	State Tax	State Tax	WV	2017	1,337,464					1,337,464	0
47	State Tax	State Tax	WV	2018	257,890					257,890	0
48	State Tax	State Tax	WV	2019	58,958					58,958	0
49	State Tax	State Tax	WV	2020	(89,021)					(89,021)	0
50	State Tax	State Tax	WV	2021	(1,874,768)					(1,874,768)	0
51	State Tax	State Tax	WV	2022	332,518					332,518	0
52	State Tax	State Tax	WV	2023			469,368			469,368	

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR	
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)
53	State Tax	State Tax	FIN48		(126)		126			0	0
54	**Subtotal State Tax**				2,560,996	0	20,940,833	16,019,855	0	7,481,974	0
55	Local Tax	Local Tax	MI	2019	(30,028)	0				(30,028)	0
56	Local Tax	Local Tax	MI	2008	(1,279)	0				(1,279)	0
57	Local Tax	Local Tax	MI	2013	18	0				18	0
58	Local Tax	Local Tax	MULTI	2008	1,279	0				1,279	0
59	Local Tax	Local Tax	MULTI	2013	(18)	0				(18)	0
60	Local Tax	Local Tax	MULTI	2017	(1,261)	0				(1,261)	0
61	Local Tax	Local Tax	OH	2018	(1,200)	0				(1,200)	0
62	Local Tax	Local Tax	OH	2020	(2,000)	0				(2,000)	0
63	Local Tax	Local Tax	OH	2021	(100)	0				(100)	0
64	Local Tax	Local Tax	OH	2022				154		(154)	
65	**Subtotal Local Tax**				(34,589)	0	0	154	0	(34,743)	0
66	Real Prop Leased	Real Estate Tax	IN	2022						0	
67	Real Prop Leased	Real Estate Tax	MI	2021	4,268		40,304	44,572		0	
68	Real Prop Leased	Real Estate Tax	MI	2022			217,348	217,348		0	
69	Real Prop Leased	Real Estate Tax	IN	2023			240,352	240,352		0	
70	Real Prop Leased	Real Estate Tax	MI	2023						0	
71	Personal Prop Leased	Real Estate Tax	IN	2022	1,369,500		(18)	1,369,482		0	
72	Personal Prop Leased	Real Estate Tax	IN	2023			1,086,900			1,086,900	
73	Personal Prop Leased	Real Estate Tax	MI	2021	24,695		21,110	45,805		0	
74	Personal Prop Leased	Real Estate Tax	MI	2022	62,738			45,551		17,187	
75	Personal Prop Leased	Real Estate Tax	MI	2023			81,143			81,143	
76	**Subtotal Real Estate Tax**				1,461,201	0	1,687,139	1,963,110	0	1,185,230	0
77	Real & Pers Prop	Property Tax	AR	2022		0	3,661	3,661		0	0
78	Real & Pers Prop	Property Tax	CO	2021		0				0	0
79	Real & Pers Prop	Property Tax	IL	2022		0	974	974		0	0
80	Real & Pers Prop	Property Tax	IN	2020		0				0	0
81	Real & Pers Prop	Property Tax	IN	2021		0	(263)	(263)		0	0
82	Real & Pers Prop	Property Tax	IN	2022	21,251,266	0	(3,559,863)	17,691,403		0	0
83	Real & Pers Prop	Property Tax	IN	2023		0	22,440,457	(215)		22,440,672	0
84	Real & Pers Prop	Property Tax	KY	2020	86,401	0	(86,401)			0	0
85	Real & Pers Prop	Property Tax	KY	2021	528,000	0	64,688	592,688		0	0
86	Real & Pers Prop	Property Tax	KY	2022	538,000	0				538,000	0
87	Real & Pers Prop	Property Tax	LA	2023	0	0	2,546	2,546		0	0
88	Real & Pers Prop	Property Tax	MI	2020		0				0	
89	Real & Pers Prop	Property Tax	MI	2021	17,045,366	0	(2,915,894)	14,129,472		0	0
90	Real & Pers Prop	Property Tax	MI	2022	52,624,703	0	(30)	38,049,277		14,575,396	0
91	Real & Pers Prop	Property Tax	MI	2023		0	51,257,655	30		51,257,625	0
92	Real & Pers Prop	Property Tax	MO	2022	1,279	0	(1,279)			0	0
93	Real & Pers Prop	Property Tax	MO	2023		0	19,093	19,093		0	0
94	Real & Pers Prop	Property Tax	TN	2022	0	0	2,575	2,575		0	0
95	Real & Pers Prop	Property Tax	TN	2023	0	0				0	0
96	Real & Pers Prop	Property Tax	WV	2021	66,072	0		66,072		0	0
97	Real & Pers Prop	Property Tax	WV	2022	156,000	0	5,729	96,755		64,974	0
98	Real & Pers Prop	Property Tax	WV	2023		0	163,000			163,000	0
99	Real & Pers Prop	Property Tax	WY	2021	390	0	(390)			0	0
100	Real & Pers Prop	Property Tax	WY	2022		0	2,082	2,082		0	0
101	Real & Pers Prop	Property Tax	AZ	2019	0	0				0	0
102	Real & Pers Prop	Property Tax	MS	2022	0	0	6	6		0	0
103	Real & Pers Prop	Property Tax	KY	2023			593,274	274		593,000	

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)
104	**Subtotal Property Tax**				92,297,477	0	67,991,620	70,656,430	0	89,632,667	0
105	STATE UNEMPLOYMENT 2020	Unemployment Tax	WV	2020						0	
106	UNEMPLOYMENT 2023	Unemployment Tax			3,264		120,446	98,344		25,366	
107	STATE UNEMPLOYMENT 2023	Unemployment Tax	IN		31,222		229,964	221,033		40,153	
108	STATE UNEMPLOYMENT 2023	Unemployment Tax	MO							0	
109	STATE UNEMPLOYMENT 2023	Unemployment Tax	MI		45,549		253,524	238,434		60,639	
110	STATE UNEMPLOYMENT 2023	Unemployment Tax	OH				943	745		198	
111	STATE UNEMPLOYMENT 2023	Unemployment Tax	VA							0	
112	STATE UNEMPLOYMENT 2023	Unemployment Tax	WV				15,414	15,499		(85)	
113	**Subtotal Unemployment Tax**				80,035	0	620,291	574,055	0	126,271	0
114	Util Receipts Tax	Other Taxes	IN	2021						0	
115	Util Receipts Tax	Other Taxes	IN	2022	(52,519)		485,271	432,752		0	
116	**Subtotal Other Tax**				(52,519)	0	485,271	432,752	0	0	0
117	**Subtotal Income Tax**				0	0	0	0	0	0	0
118	Excise Tax	Excise Tax		2021	0					0	0
119	Excise Tax	Excise Tax		2022	281,472		2,320	152,942		130,850	0
120	Excise Tax	Excise Tax		2023			610,423	378,159		232,264	
121	**Subtotal Excise Tax**				281,472		612,743	531,101	0	363,114	0
122	Fuel Tax	Fuel Tax	IN	2021						0	
123	Fuel Tax	Fuel Tax	IN	2022		451,271	902,542	451,271		0	
124	Fuel Tax	Fuel Tax	MI	2021						0	
125	Fuel Tax	Fuel Tax	MI	2022		233,381	324,636	91,256		(1)	
126	Special Fuel Tax	Fuel Tax	WV	2022	25,886			25,883		3	
127	Special Fuel Tax	Fuel Tax	WV	2023			146,063	114,658		31,405	
128	**Subtotal Fuel Tax**				25,886	684,652	1,373,241	683,068	0	31,407	0
129	FICA 2023	Federal Insurance Tax			2,121,897	0	18,547,455	19,126,452	0	1,542,900	
130	**Subtotal Federal Insurance Tax**				2,121,897	0	18,547,455	19,126,452	0	1,542,900	0
131	Franchise Tax	Franchise Tax	KY	2017	9,767	0				9,767	0
132	Franchise Tax	Franchise Tax	KY	2018	26,789	0				26,789	0
133	Franchise Tax	Franchise Tax	KY	2019	5,500	0				5,500	0
134	Franchise Tax	Franchise Tax	KY	2020	1,817	0				1,817	0
135	Franchise Tax	Franchise Tax	WV	2019	7,900	0				7,900	0
136	**Subtotal Franchise Tax**				51,773	0	0	0	0	51,773	0
137	**Subtotal Miscellaneous Other Tax**				0	0	0	0	0	0	0
138	**Subtotal Other Federal Tax**				0	0	0	0	0	0	0
139	Other State Tax	Other State Tax									
140	**Subtotal Other State Tax**				0	0	0	0	0	0	0
141	**Subtotal Other Property Tax**				0	0	0	0	0	0	0

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (e)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR Taxes Accrued (Account 236) (j)	BALANCE AT END OF YEAR Prepaid Taxes (Included in Account 165) (k)
142	Sales Tax	Sales And Use Tax	MI	2022		631,064		(631,064)		0	
143	Sales Tax	Sales And Use Tax	MI	2023				678,717		0	678,717
144	Use Tax	Sales And Use Tax	IN	2002						0	
145	Use Tax	Sales And Use Tax	IN	2021						0	
146	Use Tax	Sales And Use Tax	IN	2022	697,321		25,012	722,333		0	
147	Use Tax	Sales And Use Tax	IN	2023			6,517,325	6,003,083		514,242	
148	Use Tax	Sales And Use Tax	MI	2021						0	
149	Use Tax	Sales And Use Tax	MI	2022	101,965	75,381	39,184	65,768		0	
150	Use Tax	Sales And Use Tax	MI	2023			1,100,222	1,098,043		48,510	46,331
151	Use Tax	Sales And Use Tax	WV	2002						0	
152	Use Tax	Sales And Use Tax	WV	2018						0	
153	Use Tax	Sales And Use Tax	WV	2021						0	
154	Use Tax	Sales And Use Tax	WV	2022	1,452			1,452		0	
155	Use Tax	Sales And Use Tax	WV	2023			42,616	40,255		2,361	
156	**Subtotal Other Use Tax**				800,738	706,445	7,724,359	7,978,587	0	565,113	725,048
157	Ohio CAT Tax	Other Ad Valorem Tax	OH	2022			29,762	29,762		0	
158	Ohio CAT Tax	Other Ad Valorem Tax	OH	2023			2,410	10		2,400	
159	**Subtotal Other Advalorem Tax**				0	0	32,172	29,772	0	2,400	0
160	State License Registration	Other License And Fees Tax	MI	2019	(25)		25			0	0
161	State License Registration	Other License And Fees Tax	MI	2020	(25)		25			0	0
162	State License Registration	Other License And Fees Tax	wv	2019	(25)		26			1	0
163	**Subtotal Other License And Fees Tax**				(75)	0	76	0	0	1	0
164	**Subtotal Payroll Tax**				0	0	0	0	0	0	0
165	**Subtotal Advalorem Tax**				0	0	0	0	0	0	0
166	Public Serv Comm	Other Allocated Tax	MI	2022	0	0			0	0	
167	**Subtotal Other Allocated Tax**				0	0	0	0	0	0	0
168	**Subtotal Severance Tax**				0	0	0	0	0	0	0
169	**Subtotal Penalty Tax**				0	0	0	0	0	0	0
170	**Subtotal Other Taxes And Fees**				0	0	0	0	0	0	0
40	TOTAL				102,988,689	1,391,097	204,550,917	202,140,562	0	104,732,995	725,048

Line No.	DISTRIBUTION OF TAXES CHARGED			
	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	100,281,327			(15,745,610)
2	100,281,327	0	0	(15,745,610)
3				
4				
5				
6				
7				
8				
9				
10	369,245			(7,106)
11				
12				
13				
14				
15				
16				
17				
18	16,704,212			(762,407)
19				
20				
21				
22				
23				
24				
25	226,236			(8,435)
26				
27				
28				
29				
30				
31				
32	4,149,260			(200,039)
33				
34				
35				
36				
37				
38				
39	358			(230)
40				
41				
42				
43	245			
44				
45				
46				
47				
48				
49				
50				
51				
52	488,687			(19,319)
53				126

Line No.	DISTRIBUTION OF TAXES CHARGED			
	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
54	21,938,243	0	0	(997,410)
55				
56				
57				
58				
59				
60				
61				
62				
63				
64				
65	0	0	0	0
66				
67	40,304			
68	217,348			
69				240,351
70				
71	(18)			
72	1,086,900			
73	21,111			
74	62,738			(62,738)
75				81,143
76	1,428,383	0	0	258,756
77				3,661
78				
79				974
80				
81	(263)			
82	(3,551,879)			(7,984)
83	20,766,369			1,674,088
84				(86,401)
85				64,688
86				
87				2,546
88	96,000			(96,000)
89	(2,915,894)			
90	52,152,336			(52,152,366)
91				51,257,655
92				(1,279)
93				19,093
94				2,575
95				
96				
97	2,730			2,999
98				163,000
99				(390)
100				2,082
101				
102				6
103				593,274
104	66,549,399	0	0	1,442,221
105				
106	80,362			40,084

Line No.	DISTRIBUTION OF TAXES CHARGED			
	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
107	125,727			104,237
108				
109	175,230			78,294
110	699			244
111				
112	(5,046)			20,460
113	376,972	0	0	243,319
114				
115	485,271			
116	485,271	0	0	0
117	0	0	0	0
118				
119				2,320
120	9,200			601,222
121	9,200	0	0	603,542
122				
123				902,542
124				
125				324,638
126				
127				146,062
128	0	0	0	1,373,242
129	11,534,664			7,012,791
130	11,534,664	0	0	7,012,791
131				
132				
133				
134				
135				
136	0	0	0	0
137	0	0	0	0
138	0	0	0	0
139				
140	0	0	0	0
141	0	0	0	0
142				
143				
144				
145				
146				25,011
147	(131,106)			6,648,430
148				
149	982			38,201
150	166,814			933,409
151				
152				
153				
154				
155	(84)			42,700
156	36,606	0	0	7,687,751
157	29,762			0
158	2,410			0
159	32,172	0	0	0

Line No.	DISTRIBUTION OF TAXES CHARGED			
	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
160	25			
161	25			
162	26			
163	76	0	0	0
164	0	0	0	0
165	0	0		0
166	0			
167	0	0	0	0
168	0	0	0	0
169	0	0	0	0
170		0	0	0
40	202,672,313	0	0	1,878,602

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%				411.4					
3	4%				411.4					
4	7%	158,061			411.4	31,761		126,300		
5	10%	3,099,280	411.1		411.4	1,149,037		1,950,243	43 Years	
6	State DITC		411.1		411.4					
7	30%	14,093,358			411.4	397,177		13,696,181		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	17,350,699				1,577,975		15,772,724		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
47	OTHER TOTAL									
48	GRAND TOTAL	17,350,699						15,772,724		

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Pole Attachment Rentals	772,740	454/253/186/456	2,431,920	2,405,218	746,038
2	IPP-System Upgrade Credits	4,106,273	421/431	4,306,110	199,837	
3	Defd Gain-Fiber Optics Agrmt In Kind Service-Amrtz thru 2025	1,570,805	124	615,873		954,932
4	Deferred Revenues-Verizon Amortized thru March 2023	11,863	451	11,863		
5	Customer Advance Receipts	10,682,874	142	10,682,874	12,283,391	12,283,391
6	Deferred Revenue	2,971,366	142/143/186	2,971,366	303,873	303,873
7	Contract Settlement Reserves	317,466	186	317,467	95,387	95,386
8	Minor Items	318,601	107/108/142/186/234	386,632	1,158,301	1,090,270
9	QUAL OF SVC PENALTIES - LT	248,335	242	26,013		222,322
10	PJM Provision True Up	4,439,364	456/253/229/449	6,414,377	15,017,910	13,042,897
47	TOTAL	25,439,687		28,164,495	31,463,917	28,739,109

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)	CHANGES DURING YEAR: Amounts Debited to Account 410.2 (e)	CHANGES DURING YEAR: Amounts Credited to Account 411.2 (f)	ADJUSTMENTS Debits: Account Credited (g)	ADJUSTMENTS Debits: Amount (h)	ADJUSTMENTS Credits: Account Debited (i)	ADJUSTMENTS Credits: Amount (j)	Balance at End of Year (k)
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities	21,781,948	2,587	4,078,819							17,705,716
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)	21,781,948	2,587	4,078,819							17,705,716
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other - SFAS 109	[a](7,028,768)					254		254	1,262,954	(5,765,814)
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	14,753,180	2,587	4,078,819						1,262,954	11,939,902
18	Classification of TOTAL										
19	Federal Income Tax	14,753,180	2,587	4,078,819						1,262,954	11,939,902
20	State Income Tax										
21	Local Income Tax										

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Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesAcceleratedAmortizationProperty

Footnote 272

Line 16 Other - Detail	Balance at Beginning of Year	Balance at End of Year
SFAS 109	(7,028,768)	(5,765,814)
Total Line 16	(7,028,768)	(5,765,814)

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)
1	Account 282										
2	Electric	1,371,220,224	112,385,966	149,746,579			190	741	283		1,333,858,870
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	1,371,220,224	112,385,966	149,746,579				741			1,333,858,870
6	Others	[(a)](209,126,773)	4,706,009	2,252,185			1823/254/190	7,898,390	1823/254	47,662,951	(166,908,388)
9	TOTAL Account 282 (Total of Lines 5 thru 8)	1,162,093,451	117,091,975	151,998,764				7,899,131		47,662,951	1,166,950,482
10	Classification of TOTAL										
11	Federal Income Tax	1,162,093,451	117,091,975	151,998,764				7,898,390		47,662,210	1,166,950,482
12	State Income Tax										
13	Local Income Tax										

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Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Page 274 Footnote

	Balance at Beginning of Year	Balance at End of Year
Non-Utility	5,625,804	5,625,804
SFAS 109	(214,752,577)	(172,534,192)
Total Other - Line 6	(209,126,773)	(166,908,388)

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)	CHANGES DURING YEAR: Amounts Debited to Account 410.2 (e)	CHANGES DURING YEAR: Amounts Credited to Account 411.2 (f)	ADJUSTMENTS Debits: Account Credited (g)	ADJUSTMENTS Debits: Amount (h)	ADJUSTMENTS Credits: Account Debited (i)	ADJUSTMENTS Credits: Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric										
3	NUC DECOM TRUST - SFAS 143 - ARO - BK	632,389,754	128,906,274	23,680,254							737,615,774
4	U1-BK DEFD NUC REFUEL COSTS	17,055,837	6,831,818	12,199,284							11,688,371
5	UNIT 2 NUC FUEL TAX VS BOOK DEPR	140,350,038									140,350,038
6	UNIT 1 NUC FUEL TAX VS BOOK DEPR	134,484,324									134,484,324
7	CAPITALIZED SOFTWARE COST-BOOK	29,872,335									29,872,335
8	Other	(348,295,831)	26,453,309	53,446,940	207,938	534,505		122,243			(375,738,272)
9	TOTAL Electric (Total of lines 3 thru 8)	605,856,457	162,191,401	89,326,478	207,938	534,505		122,243			678,272,570
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other	[a]307,983,970	39	39	4,535,280	3,099,533	1823/254/1903	286,649,643	1823/254	303,972,746	326,742,820
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	913,840,427	162,191,440	89,326,517	4,743,218	3,634,038		286,771,886		303,972,746	1,005,015,390
20	Classification of TOTAL										
21	Federal Income Tax	687,433,606	162,189,418	89,324,495	4,743,218	3,634,038		46,597,298		89,688,746	804,499,157
22	State Income Tax	226,406,821	2,022	2,022				226,023,219		237,672,480	238,056,082
23	Local Income Tax										

NOTES

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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

Footnote Page 276

Line 18 Other - Detail	Balance at Beginning of Year	Balance at End of Year
Non-Utility 283.2	1,546,581	2,982,329
Provision Optimization		15,049,680
SFAS 109 283.3	306,437,390	308,710,811
Total	307,983,971	326,742,820

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Asset Retirement Oblig-Excess Provision SFAS 143	1,318,539,666	228	204,822,698	608,209,458	1,721,926,426
2	DSM Energy Optimization Program - Michigan	2,899,083	908	3,035,758	136,675	
3	Gains on Foreign Currency Derivatives, Amortization Period: 01/2009 - 12/2023	11,309	403	11,309		
4	Indiana Resource Adequecy Rider	1,571,357	555	9,688,954	8,117,597	
5	Indiana Solar Rider	399,752	403	219,267	679,737	860,222
6	Michigan Renewable Energy Surcharge	23,219,216	555	3,398,049	6,738,853	26,560,020
7	Over Recovered Fuel Costs - Indiana		440, 244	1,987,710	25,189,214	23,201,504
8	PJM Exp and OSS Margin Sharing Total	34,206,187	555	25,324,149	5,235,404	14,117,442
9	PJM Trans Enhancement	5,933,632	142	1,931,060		4,002,572
10	SFAS 109 Deferred FIT	461,682,965	190, 282, 254	53,707,369	9,600,388	417,575,983
11	SNF Trust Funds - Pre 4/83	45,837,459	128, 224, 254, 518	77,072,461	78,846,799	47,611,797
12	Unrealized Gain on Forward Commitments	618,493	175, 244, 254	624,021	5,527	(1)
13	Indiana DSM Program		908	2,276,196	18,953,647	16,677,451
14	PJM Transmission True-up Deferral				22,848,167	22,848,167
41	TOTAL	1,894,919,119		384,099,001	784,561,466	2,295,381,583

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

Electric Operating Revenues

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.
6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	828,636,245	872,376,472	5,169,204	5,507,591	531,024	528,350
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	561,175,473	568,225,756	4,971,167	4,739,785	72,925	72,655
5	Large (or Ind.) (See Instr. 4)	588,309,598	629,632,357	7,308,668	7,492,111	4,803	4,832
6	(444) Public Street and Highway Lighting	4,896,190	5,163,649	54,903	55,614	1,895	1,897
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	[a]1,983,017,506	[d]2,075,398,234	17,503,941	17,795,101	610,647	607,734
11	(447) Sales for Resale	246,181,792	540,875,798	5,862,370	7,919,389	7	9
12	TOTAL Sales of Electricity	2,229,199,298	2,616,274,032	23,366,311	25,714,490	610,654	607,743
13	(Less) (449.1) Provision for Rate Refunds	13,780,316	27,927,976				
14	TOTAL Revenues Before Prov. for Refunds	2,215,418,982	2,588,346,056	23,366,311	25,714,490	610,654	607,743
15	Other Operating Revenues						
16	(450) Forfeited Discounts	5,750,618	5,622,051				
17	(451) Miscellaneous Service Revenues	1,886,385	1,917,149				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	15,275,671	13,035,615				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[b]29,156,429	23,546,840				
22	(456.1) Revenues from Transmission of Electricity of Others	[c]37,646,166	51,512,944				
23	(457.1) Regional Control Service Revenues	61,600					
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	89,776,869	95,634,599				
27	TOTAL Electric Operating Revenues	2,305,195,850	2,683,980,655				

Line12, column (b) includes $ 216,260 of unbilled revenues.
Line12, column (d) includes (5,204) MWH relating to unbilled revenues

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: SalesToUltimateConsumers

Detail of unmetered Sales:

	Revenue	MWH	Average No.of Customers
Residential	2,435,811.00	13,089.00	18,332.00
Commercial	4,224,565.00	28,922.00	10,632.00
Industrial	812,679.00	6,007.00	1,309.00
Public Street Lighting	62,268.00	428.00	126.00
Total	**7,535,323.00**	**48,446.00**	**30,399.00**

(b) Concept: OtherElectricRevenue

	2023	2022
Associated Business Development	2,669,711.00	3,742,525.00
DSM Revenues	—	—
Other -Nonaffiliated	9,322.00	137,598.00
Misc Revenues<$250,000	18,230.00	—
Sales of Renew.Energy Credits	26,459,166.00	19,666,717.00
	29,156,429.00	**23,546,840.00**

(c) Concept: RevenuesFromTransmissionOfElectricityOfOthers

PJM Revenues

(d) Concept: SalesToUltimateConsumers

Detail of unmetered Sales:

	Revenue	MWH	Average No. of Custom
Residential	2,518,952.00	13,347.00	18,407.00
Commercial	4,305,671.00	29,075.00	10,556.00
Industrial	830,601.00	6,112.00	1,304.00
Public Street Lighting	62,221.00	422.00	123.00
Total	**7,717,445.00**	**48,956.00**	**30,390.00**

Total Sales to Ultimate Consumers include $2,384,403 of operating revenues for distribution service provided to Open Access Customers. Megawatt hours delivered to Open Access Customers were $279,897 and are included in the reported Megawatt hours sold on pg. 301 (d).

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
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46	TOTAL				61,600

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Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Medium General Service	1	2,442	0		2.4420
2	Residential Service	5,013,689	820,314,830	516,497	9,707	0.1636
3	Residential Service TOD	76,642	10,920,205	5,216	14,694	0.1425
4	Residential Service Flat	15,199	2,737,047	1,662	9,145	0.1801
5	Residential Service PEV	2,739	32,260	322	8,506	0.0118
6	Res Off-Peak Energy Stor	20,946	2,896,787	1,190	17,602	0.1383
7	Res Svc Opt Senior Citizen	34,090	4,042,287	6,137	5,555	0.1186
8	Outdoor Lighting (Indiana)	13,089	2,435,811			0.1861
9	Outdoor Lighting (Indiana) -OAD	1	88			0.0880
10	Unrecovered Fuel		(14,454,019)			
11	FAC191 fuel provisoin		46,512			
41	TOTAL Billed Residential Sales	5,176,396	828,974,250	531,024	9,748	0.1601
42	TOTAL Unbilled Rev. (See Instr. 6)	(7,192)	(338,005)			0.0470
43	TOTAL	5,169,204	828,636,245	531,024	9,734	0.1603

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3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential Service	2	2,708			1.3540
2	Electric Heating General	4,249	639,459	116	36,629	0.1505
3	Electric Heating Schools	5,235	605,423	13	402,692	0.1156
4	Energy Conserv Lighting	6,706	1,080,049	11	609,636	0.1611
5	GS PEV	15	(172)	4	3,750	(0.0115)
6	Industrial Services	799,562	71,655,515	54	14,806,704	0.0896
7	Irrigation Service	11,665	2,477,855	634	18,399	0.2124
8	Large General Service	1,994,985	219,038,138	3,842	519,257	0.1098
9	Large General Service OAD Self Supply	14,579	166,258	5	2,915,800	0.0114
10	Large General Service TOD	69,838	8,124,066	495	141,087	0.1163
11	Large Power	284,435	17,699,675	4	71,108,750	0.0622
12	Large Power OAD Self Supply	31,444	368,599	1	31,444,000	0.0117
13	Medium General Service	1,410,312	217,448,400	63,428	22,235	0.1542
14	Medium General Service Flat	476	83,148	36	13,222	0.1747
15	Medium General Service OAD	647	28,803	4	161,750	0.0445
16	Medium General Service OAD Self Supply	2,558	54,673	14	182,714	0.0214
17	Medium General Service TOD	70,969	9,135,444	2,014	35,238	0.1287
18	Municipal and School Service	43,492	5,905,451	413	105,308	0.1358
19	Outdoor lightning	28,922	4,224,565	0		0.1461
20	Outdoor Lighting OAD	2	286	0		0.1430
21	Small General Service	2,714	399,030	510	5,322	0.1470
22	Small General Service TOD	551	90,921	64	8,609	0.1650
23	Street Light Customer Owned Metered	5,486	273,142	568	9,658	0.0498
24	Street Light Service	80	23,783	4	20,000	0.2973
25	Estimated	24,325	1,831,145			0.0753
26	Res Off Peak Energy Storage		82			
27	Resi Service Opt Senior Citizen		33			
28	Residential Service PEV		18			
29	Residential Service TOD		183			
30	Water and Sewage Service	156,921	14,319,141	691	227,093	0.0913
31	FAC191 fuel provisoin		31,189			
32	Unrecovered Fuel		(14,838,798)			
41	TOTAL Billed Small or Commercial	4,970,170	560,868,212	72,925	68,155	0.1128
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	997	307,261			0.3082
43	TOTAL Small or Commercial	4,971,167	561,175,473	72,925	68,168	0.1129

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Electric Heating General	347	53,605	7	49,571	0.1545
2	Medium General Service	386,129	64,069,191	3,454	111,792	0.1659
3	Medium General Service - TOD	2,846	379,958	48	59,292	0.1335
4	Medium General Service OAD	6,563	379,869	10	656,300	0.0579
5	Medium General Service Flat	224	67,200	2	112,000	0.3000
6	Medium General Service OAD Self Supply	248	11,434	3	82,667	0.0461
7	Large General Service	1,067,260	126,453,468	1,072	995,578	0.1185
8	Large General Service - TOD	2,594	344,920	7	370,571	0.1330
9	Large General Service OAD Self supply	138	5,918	1	138,000	0.0429
10	Large Power	318,548	28,445,936	18	17,697,111	0.0893
11	Large Power OAD	11,112	248,092	1	11,112,000	0.0223
12	Large Power OAD Self Supply	212,995	1,127,733	5	42,599,000	0.0053
13	Industrial Service	5,485,365	403,310,887	161	34,070,590	0.0735
14	Water & Sewage Service	4,105	387,403	7	586,429	0.0944
15	Outdoor Lighting	6,007	812,679			0.1353
16	Energy Conserv Lighting	36	4,715	1	36,000	0.1310
17	Estimated Revenue	(196,897)	(11,397,274)			0.0579
18	Resi Service Opt Senior Citizen		18			
19	Residential Service		203			
20	Outdoor Lighting OAD	4	377			0.0943
21	Small General Service	56	7,530	6	9,333	0.1345
22	FAC191 fuel provisoin		70,999			
23	Unrecovered Fuel		(26,721,910)			
41	TOTAL Billed Large (or Ind.) Sales	7,307,680	588,062,951	4,803	1,521,482	0.0805
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	988	246,647			0.2496
43	TOTAL Large (or Ind.)	7,308,668	588,309,598	4,803	1,521,688	0.0805

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Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Small General Service	148	27,493	69	2,145	0.1858
2	Medium General Service TOD	159	30,929	40	3,975	0.1945
3	Ft Wayne Street Lighting	20,951	659,477	1	20,951,000	0.0315
4	Energy Conservation Lighting	17,752	2,583,839	212	83,736	0.1456
5	Street Light - Customer Owned	5,502	263,359	399	13,789	0.0479
6	Street Lighting Service	6,983	682,218	78	89,526	0.0977
7	Municipal & School Service	249	43,027	33	7,545	0.1728
8	Outdoor Lighting	428	62,268			0.1455
9	Medium General Service	2,728	721,309	1,063	2,566	0.2644
10	Residential Service		167			
11	Residential Service TOD		9			
12	FAC191 fuel provisoin		(39,534)			
13	Unrecovered Fuel		(138,728)			
41	TOTAL Billed Public Street and Highway Lighting	54,900	4,895,833	1,895	28,971	0.0892
42	TOTAL Unbilled Rev. (See Instr. 6)	3	357			0.1190
43	TOTAL	54,903	4,896,190	1,895	28,973	0.0892

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6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
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41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		13,780,316			

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	17,509,146	1,982,801,246	610,647	28,673	0.1132
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(5,204)	216,260			(0.0416)
43	TOTAL - All Accounts	17,503,942	1,983,017,506	610,647	28,673	0.1133

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SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.

   SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

   LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

   OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

   AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (g) through (k).
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW) Average Monthly NCP Demand (e)	ACTUAL DEMAND (MW) Average Monthly CP Demand (f)	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)
1	CITY OF AUBURN	RQ	NOTE 1				324,444	16,259,652	11,137,502		27,397,154
2	CITY OF DOWAGIAC, MI	RQ	NOTE 1				56,799	3,304,924	2,012,290		5,317,214
3	DP&L POWER SERVICES	OS	NOTE 1				(1)		(67)		(67)
4	EVOLUTION MARKETS FUTURES, LLC	OS	NOTE 1				0		(10,615)		(10,615)
5	INDIANA MUNICIPAL POWER AGENCY	RQ	NOTE 1				1,594,588	71,614,831	45,881,054		117,495,885
6	PJM INTERCONNECTION	OS	NOTE 1				3,110,262	(222,733)	76,101,656		75,878,923
7	PJM TRANSMISSION FOR RQ CUSTOMERS	RQ	VARIOUS				0			(52,384,243)	(52,384,243)
8	RBC CAPITAL MARKET, LLC	OS	NOTE 1				0		(22,014)		(22,014)
9	WABASH VALLEY POWER ASSN INC.	RQ	NOTE 1				776,278	44,756,963	27,764,640		72,521,603
10	WELLS FARGO SECURITIES, LLC	OS	NOTE 1				0		(12,048)		(12,048)
15	Subtotal - RQ						2,752,109	135,936,370	86,795,486	(52,384,243)	170,347,613
16	Subtotal-Non-RQ						3,110,261	(222,733)	76,056,912		75,834,179
17	Total						5,862,370	135,713,637	162,852,398	(52,384,243)	246,181,792

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Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,680,530	5,350,344
5	(501) Fuel	[a]28,393,142	104,980,675
6	(502) Steam Expenses	5,472,905	2,823,092
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	958,664	1,797,808
10	(506) Miscellaneous Steam Power Expenses	1,616,807	2,531,788
11	(507) Rents	14,884	68,904,440
12	(509) Allowances	2,952,358	190,327
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	42,089,290	186,578,474
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	854,365	1,804,441
16	(511) Maintenance of Structures	493,190	844,677
17	(512) Maintenance of Boiler Plant	3,594,851	6,382,407
18	(513) Maintenance of Electric Plant	1,970,081	2,866,105
19	(514) Maintenance of Miscellaneous Steam Plant	406,306	854,511
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	7,318,793	12,752,141
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	49,408,082	199,330,615
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	12,369,910	12,222,139
25	(518) Fuel	[b]99,235,736	86,277,041
26	(519) Coolants and Water	5,271,579	4,784,937
27	(520) Steam Expenses	11,722,657	12,622,438
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	5,346,518	4,748,217
31	(524) Miscellaneous Nuclear Power Expenses	[c]78,272,038	75,919,581
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	212,218,438	196,574,353
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	3,043,915	3,183,294
36	(529) Maintenance of Structures	4,540,865	4,025,143
37	(530) Maintenance of Reactor Plant Equipment	86,119,652	92,579,730
38	(531) Maintenance of Electric Plant	18,474,235	15,339,706
39	(532) Maintenance of Miscellaneous Nuclear Plant	23,682,415	17,398,562
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	135,861,082	132,526,435
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)	348,079,519	329,100,788
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	398,042	424,373
45	(536) Water for Power		
46	(537) Hydraulic Expenses	70,653	138,025
47	(538) Electric Expenses	32,460	52,927
48	(539) Miscellaneous Hydraulic Power Generation Expenses	873,342	1,048,792

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
49	(540) Rents	338	21
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	1,374,835	1,664,138
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	149,028	151,765
54	(542) Maintenance of Structures	924,603	937,663
55	(543) Maintenance of Reservoirs, Dams, and Waterways	331,616	649,891
56	(544) Maintenance of Electric Plant	313,215	224,758
57	(545) Maintenance of Miscellaneous Hydraulic Plant	22,495	47,417
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	1,740,957	2,011,494
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	3,115,792	3,675,632
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	18,688	2,622
63	(547) Fuel		
64	(548) Generation Expenses	1,075	(5,372)
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	(42,220)	708,476
66	(550) Rents	18	38
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	(22,439)	705,764
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		(35)
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant	301,373	82
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	301,373	47
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	278,934	705,811
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	325,674,558	700,037,070
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	1,040,136	1,343,263
78	(557) Other Expenses	3,390,011	3,252,637
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	330,104,705	704,632,970
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	730,987,033	1,237,445,816
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	6,570,710	7,602,380
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	173,831	199,189
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	4,813,644	4,667,162
89	(561.5) Reliability, Planning and Standards Development	166,641	174,620
90	(561.6) Transmission Service Studies	(7)	
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	1,390,481	1,326,518
93	(562) Station Expenses	[d]557,138	579,819
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	349,292	440,838
95	(564) Underground Lines Expenses	2,773	4,276
96	(565) Transmission of Electricity by Others	233,472,032	228,618,743
97	(566) Miscellaneous Transmission Expenses	1,787,600	2,115,593
98	(567) Rents	773,183	632,646
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	250,057,318	246,361,784
100	Maintenance		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
101	(568) Maintenance Supervision and Engineering	64,525	73,888
102	(569) Maintenance of Structures	43,743	29,558
103	(569.1) Maintenance of Computer Hardware	[g]23,696	11,815
104	(569.2) Maintenance of Computer Software	624,204	508,218
105	(569.3) Maintenance of Communication Equipment	41,361	55,255
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,799,156	1,569,678
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	12,058,216	9,462,828
109	(572) Maintenance of Underground Lines	22,633	72,523
110	(573) Maintenance of Miscellaneous Transmission Plant	16,418	17,578
111	TOTAL Maintenance (Total of Lines 101 thru 110)	14,693,952	11,801,341
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	264,751,269	258,163,125
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	4,495,433	4,361,546
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	4,495,433	4,361,546
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	4,495,433	4,361,546
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,736,769	2,774,673
135	(581) Load Dispatching	275,193	314,897
136	(582) Station Expenses	1,081,702	1,731,458
137	(583) Overhead Line Expenses	2,746,618	1,709,069
138	(584) Underground Line Expenses	4,459,018	4,528,651
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	76,255	162,478
140	(586) Meter Expenses	1,709,527	1,299,275
141	(587) Customer Installations Expenses	579,781	411,040
142	(588) Miscellaneous Expenses	13,260,867	14,410,723
143	(589) Rents	2,115,795	1,345,964
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	28,041,525	28,688,228
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	79,409	66,897
147	(591) Maintenance of Structures	14,754	82,245
148	(592) Maintenance of Station Equipment	1,428,747	1,291,895
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	59,069,903	52,656,226
150	(594) Maintenance of Underground Lines	1,088,631	1,482,024
151	(595) Maintenance of Line Transformers	377,679	339,024
152	(596) Maintenance of Street Lighting and Signal Systems	138,353	220,363

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
153	(597) Maintenance of Meters	61,737	60,357
154	(598) Maintenance of Miscellaneous Distribution Plant	568,618	409,576
155	TOTAL Maintenance (Total of Lines 146 thru 154)	62,827,831	56,608,607
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	90,869,356	85,296,835
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	803,797	753,260
160	(902) Meter Reading Expenses	1,280,349	1,066,546
161	(903) Customer Records and Collection Expenses	14,375,371	14,512,471
162	(904) Uncollectible Accounts	82,036	(77,586)
163	(905) Miscellaneous Customer Accounts Expenses	62,151	47,163
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	16,603,704	16,301,854
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	917,830	1,030,457
168	(908) Customer Assistance Expenses	42,479,566	6,006,322
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	27,057	49,601
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	43,424,453	7,086,380
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	96,130	182,086
176	(913) Advertising Expenses	284,671	412,478
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	380,801	594,564
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	42,782,629	42,279,429
182	(921) Office Supplies and Expenses	2,732,440	3,843,628
183	(Less) (922) Administrative Expenses Transferred-Credit	5,939,108	5,223,954
184	(923) Outside Services Employed	5,091,302	13,172,983
185	(924) Property Insurance	(f)3,138,017	(7,253,258)
186	(925) Injuries and Damages	3,996,762	5,276,819
187	(926) Employee Pensions and Benefits	(336,904)	8,278,261
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	20,762,688	18,754,857
190	(929) (Less) Duplicate Charges-Cr.	1,150,177	1,318,983
191	(930.1) General Advertising Expenses	83,001	204,699
192	(930.2) Miscellaneous General Expenses	5,182,047	5,432,218
193	(931) Rents	2,620,351	3,055,547
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	78,963,048	86,502,246
195	Maintenance		
196	(935) Maintenance of General Plant	10,193,046	11,236,575
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	89,156,094	97,738,821
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	1,240,668,143	1,706,988,941

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Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: FuelSteamPowerGeneration
The portion of account 501 that is excluded from the fuel costs in I&M's generation formula rate is identified by a query of the general ledger.
(b) Concept: NuclearFuelExpense
The portion of account 518 that is exclude from the nuclear fuel costs in I&M's generation formula rate is identified by a query of the general ledger
(c) Concept: MiscellaneousNuclearPowerExpenses
The portion of account 524 representing ARO expense that are excluded from non-fuel generation formula rate is identified by a query of the general ledger.The nuclear decommissioning expense allowed in the formula is an amount approved by the Indiana utility Regulatory Commission
(d) Concept: StationExpensesTransmissionExpense
Generation Step-Up Units' (GSU's) O&M expenses included in I&M's generation formula rates are the ratio of GSU balances to all investment for plant accounts 352 & 353 mutiplied by the balance in O&M accounts 562, 569, & 570.
(e) Concept: MaintenanceOfComputerHardwareTransmission
Allocated maintenance expenses for joint use computer hardware, computer software and communication equipment are determined by using various factors, which include number of remote terminal units, number of radios, number of employees and other factors assigned to each function.
(f) Concept: PropertyInsurance
The insurance expenses for generation included in I&M's generation formula rate are identified by a query of the general ledger.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

PURCHASED POWER (Account 555)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

   SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

   LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

   EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

   OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

   AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES MegaWatt Hours Received (i)	POWER EXCHANGES MegaWatt Hours Delivered (j)
1	[(a)] AEP GENERATING COMPANY	RQ					704,318			
2	CITY OF WINCHESTER, IN	OS					0			
3	FOWLER RIDGE II WIND FARM LLC	OS					112,988			
4	FOWLER RIDGE WIND FARM LLC	OS					193,408			
5	FRENCH PAPER	OS					86			
6	FT. WAYNE ELECTRIC JATC	OS					0			
7	HEADWATERS WIND FARM LLC	OS					622,752			
8	ICE TRADE VAULT LLC	OS					0			
9	OVEC POWER SCHEDULING	OS					752,160			
10	[(b)] OVER/UNDER PJM EXP TRACKER	OS					0			
11	[(c)] OVER/UNDER RESOURCE ADEQUACY RIDER	OS					910			
12	PJM INTERCONNECTION	OS					2,370,129			
13	WILDCAT WIND FARM	OS					320,998			
14	CONSTELLATION ENGY COMMODITIES	OS					0			
15	WELLS FARGO SECURITIES, LLC	OS					0			
15	TOTAL						5,077,749	0	0	0

Line No.	COST/SETTLEMENT OF POWER			
	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) of Settlement ($) (n)
1	78,439,672	28,390,211		106,829,883
2		136,395		136,395
3		11,696,362		11,696,362
4		14,406,896		14,406,896
5		21,988		21,988
6				
7		30,891,882		30,891,882
8				
9	32,819,793	28,104,068		60,923,861
10		(20,040,361)		(20,040,361)
11	(1,753,471)	280,954		(1,472,517)
12	4,346,636	96,525,681		100,872,317
13		21,950,580		21,950,580
14		88,191		88,191
15		(630,919)		(630,919)
15	113,852,630	211,821,928		325,674,558

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Affiliated Company
(b) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Per the IURC's Order in Cause No. 45235, I&M tracks the recovery of certain costs and revenues related to I&M's membership in PJM compared to the level in base rates.
(c) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Over-/Under-recovery accounting to track incremental changes in the Company's purchased power costs, per the IURC's Order in Cause No. 45235.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megawatt Hours Received (i)	TRANSFER OF ENERGY Megawatt Hours Delivered (j)
1	PJM Network Integ Rev - Affil	Various	Various	FNO	PJM OATT[(a)]	Various	Various			
2	PJM Network Integ Trans Rev Whlsle	Various	Various	FNO	PJM OATT	Various	Various			
3	PJM Network Integ Trans Serv	Various	Various	FNO	PJM OATT	Various	Various			
4	PJM Point to Point Trans Service	Various	Various	LFP	PJM OATT	Various	Various			
5	PJM Power Factor Credits Rev Nonaffiliated	Various	Various	OS	PJM OATT	Various	Various			
6	PJM Power Factor Credits Rev Whlsle	Various	Various	OS	PJM OATT	Various	Various			
7	PJM Trans Distribution & Metering	Various	Various	OS	PJM OATT	Various	Various			
8	PJM Trans Enhancement Rev	Various	Various	FNO	PJM OATT	Various	Various			
9	PJM Trans Enhancement Rev - Affil	Various	Various	FNO	PJM OATT	Various	Various			
10	PJM Trans Enhancement Rev Whlsle	Various	Various	FNO	PJM OATT	Various	Various			
11	PJM Trans Owner Admin Rev - Affil	Various	Various	OLF	PJM OATT	Various	Various			
12	PJM Trans Owner Admin Revenue	Various	Various	OLF	PJM OATT	Various	Various			
13	PJM Trans Owner Serv Rev Whlsle	Various	Various	OLF	PJM OATT	Various	Various			
35	TOTAL									

Line No.	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	(586,111)			(586,111)
2	5,477,936			5,477,936
3	22,506,330			22,506,330
4	4,416,069			4,416,069
5			501,973	501,973
6			21,558	21,558
7			737,485	737,485
8	4,302,776			4,302,776
9	718			718
10	117,861			117,861
11		486	[(b)](1)	485
12		140,661		140,661
13		8,424		8,424
35	36,235,579	149,571	1,261,015	37,646,166

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: RateScheduleTariffNumber
Effective October 1, 2004, the administration of the transmission tariff was turned over to PJM. PJM does not provide any detail except for the total revenue by the major classes listed. OATT (Open Access Transmission Tariff) 3rd revised Volume No. 6
(b) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Per Proforma ILDSA (Interconnection and Local Delivery Service Agreement) AEP Tariff 3rd Revised Volume No. 6

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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39					
40					
41					
42					
43					

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
44					
45					
46					
47					
48					
49					
40	TOTAL				
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TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:
FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter ""TOTAL"" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: MegaWatt Hours Received (c)	TRANSFER OF ENERGY: MegaWatt Hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	PJM Enhancements	OS	0	0			[a]21,401,489	21,401,489
2	PJM-Trans Owner Serv	OS	0	0			[b](129,642)	(129,642)
3	PJM NITS	OS	0	0			[c]212,200,184	212,200,184
	TOTAL		0	0			233,472,032	233,472,032

FOOTNOTE DATA

(a) Concept: OtherChargesTransmissionOfElectricityByOthers
Transmission Enhancement Charges and Credits (PJM OATT Schedule 12)
(b) Concept: OtherChargesTransmissionOfElectricityByOthers
Transmission Owner Service (PJM OATT Tariff Sixth Revised Volume No. 1)
(c) Concept: OtherChargesTransmissionOfElectricityByOthers
Network Integration Transmission Service Charges - NITS (PJM OATT Schedule H)

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	3,485,290
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	13,322
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Associated Business Development	1,138,735
7	American Electric Power Service Corp Billings	679,491
8	Corporate Money Pool Allocations	48,844
9	Corporate Legal and Financing	64,290
10	Corporate Contributions and Memberships	136,563
11	Intercompany Billings	(383,657)
12	Minor iItems	(831)
46	TOTAL	5,182,047

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

1. Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
   Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
   In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
   For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			44,820,927		44,820,927
2	Steam Production Plant	92,755,606	1,578,876	848,869		95,183,351
3	Nuclear Production Plant	159,158,595	427,243			159,585,838
4	Hydraulic Production Plant-Conventional	2,118,478	12,893			2,131,371
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	3,555,102				3,555,102
7	Transmission Plant	48,000,467				48,000,467
8	Distribution Plant	92,998,528				92,998,528
9	Regional Transmission and Market Operation					
10	General Plant	7,748,775	33,728	259,293		8,041,796
11	Common Plant-Electric					
12	TOTAL	406,335,551	2,052,740	45,929,089		454,317,380

B. Basis for Amortization Charges

Section A, Line 1, Column D represents amortization of franchises over the life of the franchise, amorization of capitalized software development cost over a 5 year life and the amortization of costs associated with the Oracle strategic partnership over a 10 year life. Section A, Line 2, Column D represents amortization of Rockport Unit 2 Leasehold Improvements over the life of Rockport Unit 2 Lease. Section A, Line 10, Column D represents amortization of leasehold improvements over the lives of the related assets.

Line No.	C. Factors Used in Estimating Depreciation Charges						
	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM						
13	311 - Rockport U1	98.872					
14	311 - Rockport U2	4.201					
15	311 - Rkpt DSI U1	2.905					
16	311 - Rkpt DSI U2	0.787					
17	312 - Rockport ACI	11.839					
18	312 - Rockport U1	426.488					
19	312 - Rockport U2	26.296					
20	312 - Rockport U1 -SCR	138.402					
21	312 - Rockport U2 -SCR	110.879					
22	312 - Rkpt DSI U1	51.747					
23	312 - Rkpt DSI U1 - Pre	24.807					
24	312 - Rkpt DSI U2	54.117					
25	314 - Rockport U1	105.699					
26	314 - Rockport U2	0.867					
27	315 - Rockport U1	59.191					
28	315 - Rockport U2	2.088					
29	316 - Rockport U1	18.184					
30	316 - Rockport U1-SCR	0.008					
31	316 - Rockport U2	6.845					
32	TOTAL STEAM	1,144.222					
33	NUCLEAR						
34	321 - Cook U1	89.061					
35	321 - Cook U2	383.686					
36	322 - Cook U1	770.355					
37	322 - Cook U2	1,020.881					
38	323 - Cook U1	304.754					
39	323 - Cook U2	414.856					
40	324 - Cook U1	145.083					
41	324 - Cook U2	205.936					
42	325 - Cook U1	36.378					
43	325 - Cook U2	256.701					
44	TOTAL NUCLEAR	3,627.691					
45	HYDRO						
46	331 - Berrien Springs	1.982					
47	331 - Buchanan	0.61					
48	331 - Constantine	0.452					
49	331 - Crew Service Center	0.417					
50	331 - Elkhart	1.049					
51	331 - Mottville	1.329					
52	331 - Twin Branch	0.865					
53	332 - Berrien Springs	5.409					
54	332 - Buchanan	4.711					
55	332 - Constantine	1.229					
56	332 - Elkhart	7.085					
57	332 - Mottville	2.188					
58	332 - Twin Branch	5.102					
59	333 - Berrien Springs	7.178					
60	333 - Buchanan	1.566					
61	333 - Constantine	0.737					
62	333 - Elkhart	0.572					
63	333 - Mottville	0.605					
64	333 - Twin Branch	5.998					

Line No.	C. Factors Used in Estimating Depreciation Charges						
	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
65	334 - Berrien Springs	1.634					
66	334 - Buchanan	1.032					
67	334 - Constantine	0.499					
68	334 - Elkhart	1.083					
69	334 - Mottville	0.75					
70	334 - Twin Branch	1.741					
71	335 - Berrien Springs	0.804					
72	335 - Buchanan	0.292					
73	335 - Constantine	0.353					
74	335 - Crew Service Center	0.127					
75	335 - Elkhart	0.224					
76	335 - Mottville	0.387					
77	335 - Twin Branch	0.668					
78	336 - Mottville	0.001					
79	TOTAL HYDRO	58.739					
80	OTHER GENERATION						
81	341 - Olive Solar	0.377					
82	341 - Watervliet Solar	0.358					
83	344 - Deer Creek Solar	5.668					
84	344 - Olive Solar	11.185					
85	344 - South Bend Solar	28.73					
86	344 - Twin Branch Solar	6.955					
87	344 - Watervliet Solar	11.107					
88	345 - Deer Creek Solar	0.721					
89	345 - Olive Solar	0.269					
90	345 - South Bend Solar	3.999					
91	345 - Twin Branch Solar	0.01					
92	345 - Watervliet Solar	0.012					
93	346 - Deer Creek Solar	0.015					
94	346 - Olive Solar	0.215					
95	346 - South Bend Solar	0.21					
96	346 - Watervliet Solar	0.354					
97	346 - Twin Branch Solar	0.047					
98	TOTAL OTHER	70.232					
99	TRANSMISSION						
100	350 (Rights)	64.287					
101	352	87.833					
102	353	876.363					
103	353.16	15.604					
104	354	230.531					
105	355	258.084					
106	356	318.396					
107	356.16	0.567					
108	357	11.965					
109	358	9.334					
110	358.16	0.001					
111	359	0.091					
112	TOTAL TRANSMISSION	1,873.056					
113	DISTRIBUTION						
114	360 (Rights) - IN	13.488					
115	360 (Rights) - MI	6.576					
116	361 - IN	52.807					
117	361 - MI	10.398					

Line No.	C. Factors Used in Estimating Depreciation Charges						
	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
118	362 - IN	444.202					
119	362 - MI	121.809					
120	362.16 - IN	16.208					
121	362.16 - MI	2.667					
122	363 - IN	0.107					
123	364 - IN	316.52					
124	364 - MI	109.301					
125	365 - IN	513.384					
126	365 - MI	170.323					
127	366 - IN	181.376					
128	366 - MI	19.128					
129	367 - IN	290.136					
130	367 - MI	42.335					
131	368 - IN	376.662					
132	368 - MI	65.058					
133	369 - IN	196.386					
134	369 - MI	38.426					
135	370 - IN	51.805					
136	370 - MI	4.573					
137	370 - AMI	105.089					
138	371 - IN	23.482					
139	371 - MI	9.137					
140	373 - IN	23.486					
141	373 - MI	5.638					
142	TOTAL DISTRIBUTION	3,210.507					
143	GENERAL PLANT						
144	390	82.511					
145	391	6.672					
146	392	0.071					
147	393	1.457					
148	394	21.709					
149	395	0.578					
150	396	0.544					
151	397	74.018					
152	397.16	3.186					
153	398	13.966					
154	TOTAL GENERAL PLANT	204.712					
155	DEPRECIABLE SUM	[a]10,189.159					

FOOTNOTE DATA

(a) Concept: DepreciablePlantBase

The depreciable plant base is the November 30, 2023 total company depreciable plant.

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REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

						EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO						
Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1	Nuclear Regulatory Commission - Inspection and Licensing Fees	2,016,358		2,016,358			928	2,016,358				
2	Nuclear Regulatory Commission - Annual Fees	11,686,500		11,686,500			928	11,686,500				
3	Hydro License Fee		60,203	60,203			928	60,203				
4	Indiana Rate Case		2,188,138	2,188,138	1,136,271		928	1,213,743	595,450	928	974,395	757,326
5	Michigan Rate Case		1,241,809	1,241,809	693,800		928	1,241,809	212,779			906,579
6	Integrated Resource Plan Filing		372,189	372,189			928	372,189				
7	State Commission Fees	2,977,630		2,977,630			928	2,977,630				
8	Minor Items < $25,000		226,202	226,202			928	226,202				
46	TOTAL	16,680,488	4,088,541	20,769,029	1,830,071			19,794,634	808,229		974,395	1,663,905

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:
   Classifications:
   - A. Electric R, D and D Performed Internally:
     1. Generation
        - a. hydroelectric
          - i. Recreation fish and wildlife
          - ii. Other hydroelectric
        - b. Fossil-fuel steam
        - c. Internal combustion or gas turbine
        - d. Nuclear
        - e. Unconventional generation
        - f. Siting and heat rejection
     2. Transmission
        - a. Overhead
        - b. Underground
     3. Distribution
     4. Regional Transmission and Market Operation
     5. Environment (other than equipment)
     6. Other (Classify and include items in excess of $50,000.)
     7. Total Cost Incurred
   - B. Electric, R, D and D Performed Externally:
     1. Research Support to the electrical Research Council or the Electric Power Research Institute
     2. Research Support to Edison Electric Institute
     3. Research Support to Nuclear Power Groups
     4. Research Support to Others (Classify)
     5. Total Cost Incurred
3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
7. Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1	A(1)b: Generation: Fossil Fuel Steam	Generation Program Management	91,882		506,524	91,882	
2		2 items < $50,000	9,405		506	9,405	
3	A(1)e: Generation: Unconventional	1 item <$50,000	162		506	162	
4	A(2): Transmission	1 item <$50,000	5,294		566	5,294	
5	A(3): Distribution	1 item <$50,000	8,767		588	8,767	
6	A (4)d Nuclear Management	1 item <$50,000	16,619		524	16,619	
7	A(5): Environment (other than equipment)	2 items <$50,000	196		506	196	
8	A(6): Other	2 items <$50,000	192		506,524,566,588	192	
9	A(6)f: Other: Metering	1 item <$50,000	1,395		588	1,395	
10	A(6)g: Research-General	1 item <$50,000	1,221		566,588	1,221	
11	A(7) TOTAL COSTS INCURRED INTERNALLY		135,133			135,133	
12	B: Electric R&D External	4 items <$50,000		51,579	506,524,566,588	51,579	
13	B(1): Research Support to Electric Research	EPRI Research Portfolio		484,259	506,566,588	484,259	
14		EPRI Nuclear Annual Research		1,507,876	524	1,507,876	
15		IT - EPRI Annual Research Port		96,566	506,524,566,588	96,566	
16		EPRI Environmental Science		134,716	506	134,716	
17		Low Carbon Resource Initiative		167,477	506,524,566,588	167,477	
18		23 items <$50,000		42,716	506,524,566,588	42,716	
19	(B4): Steam Power	2 item <$50,000		150	506,566	150	
20	B(5) TOTAL COSTS INCURRED EXTERNALLY			2,485,339		2,485,339	

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DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	85,766,363		
4	Transmission	2,117,370		
5	Regional Market			
6	Distribution	7,334,383		
7	Customer Accounts	1,915,214		
8	Customer Service and Informational	3,058,499		
9	Sales			
10	Administrative and General	2,576,056		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	102,767,885		
12	Maintenance			
13	Production	41,626,708		
14	Transmission	2,067,767		
15	Regional Market			
16	Distribution	10,685,928		
17	Administrative and General	1,614,357		
18	TOTAL Maintenance (Total of lines 13 thru 17)	55,994,760		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	127,393,071		
21	Transmission (Enter Total of lines 4 and 14)	4,185,137		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	18,020,311		
24	Customer Accounts (Transcribe from line 7)	1,915,214		
25	Customer Service and Informational (Transcribe from line 8)	3,058,499		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	4,190,413		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	158,762,645	7,794,271	166,556,916
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	158,762,645	7,794,271	166,556,916
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	57,577,632	2,826,708	60,404,340
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	57,577,632	2,826,708	60,404,340
72	Plant Removal (By Utility Departments)			
73	Electric Plant	8,326,425	408,776	8,735,201
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	8,326,425	408,776	8,735,201
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	120 - Nuclr Fuel in Proc of Refinmnt	418,865		418,865
80	121 - Nonutility Property - WIP	161		161
81	152 - Fuel Stock Undistributed	2,285,288		2,285,288
82	154 - Materials and Supplies	16,045		16,045
83	163 - Stores Expense Undistributed	8,223,816	(8,223,816)	
84	183 - Prelim Survey	47,303	(47,303)	
85	184 - Clearing Accounts	2,758,636	(2,758,636)	
86	185 - ODD Temporary Facilities	144,424		144,424
87	186 - Misc Deferred Debits	626,763		626,763
88	228 - RAD Waste Accrual	49,039		49,039
89	242 - Misc Current & Accrued Liab			
90	254 - Ohio Reliability			
91	401 - Operation Expense - Nonassociated	954		954
92	402 - Maintenance Exp			
93	407 - Regulatory Debits			
94	417 - Misc Exp	7,156,413		7,156,413
95	426 - Political Activities	70,782		70,782
95	TOTAL Other Accounts	21,798,489	(11,029,755)	10,768,734
96	TOTAL SALARIES AND WAGES	246,465,191		246,465,191
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Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	12,248,071	14,256,957	35,498,976	57,895,226
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(26,549,258)	(51,622,515)	(70,132,039)	(82,772,524)
4	Transmission Rights	(1,870,693)	(5,450,976)	(6,956,703)	(8,566,268)
5	Ancillary Services	2,760,107	6,531,818	10,001,416	14,607,759
6	Other Items (list separately)				
7	Congestion	5,887,185	10,672,834	13,264,188	14,299,778
8	Operating Reserves	(5,897,201)	(5,434,906)	(4,621,809)	(4,122,856)
9	Transmission Purchase Expense	13,700,322	27,620,136	40,767,200	52,384,922
10	Transmission Losses	2,884,884	5,410,672	7,669,925	8,212,751
11	Meter Corrections	5,556,160	4,975,813	5,020,898	5,011,731
12	Inadvertent	(49,865)	(28,647)	55,546	86,898
13	Capacity Credits	342,128	328,402	290,143	260,671
46	TOTAL	9,011,840	7,259,588	30,857,741	57,298,088

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.
In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	[(a)]0					
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)						

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedNumberOfUnits
The final grandfathered contracts (under the AEP OATT) expired 12/31/2010. Currently, services are provided under the SPP and PJM OATTs.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: 0									
1	January	[a]0								
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total				0	0	0	0	0	0

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Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: MonthlyPeakLoadExcludingIsoAndRto
Indiana Michigan Power Company's transmission service is administered through an RTO/ISO and requested information is not available on an individual operating company basis.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

Monthly ISO/RTO Transmission System Peak Load

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: 0									
1	January									
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total Year to Date/Year				0	0	0	0	0	0

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2024-04-09	Year/Period of Report End of: 2023/ Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	17,503,941
3	Steam	[a]704,318	23	Requirements Sales for Resale (See instruction 4, page 311.)	2,752,109
4	Nuclear	18,642,410	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,110,261
5	Hydro-Conventional	86,118	25	Energy Furnished Without Charge	74
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other	54,050	27	Total Energy Losses	1,198,260
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	19,486,896	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	24,564,645
10	Purchases (other than for Energy Storage)	5,077,749			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)	0			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	24,564,645			

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2024-04-09	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: SteamGeneration
Indiana Michigan Power Company purchased a 50% share of Rockport Unit 2 on December 8, 2022 and is operating as a merchant facility. Merchant operations volumes that are generated, purchased, and sold are not part of the volumes recorded on this page. Generated volumes were 679,650 for 2023, purchased volumes were 679,650 for 2023 and volumes sold to the market were 1,359,300 for 2023 .

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: 0					
29	January	2,230,235	329,039	[(a)(b)] 3,099	31	10
30	February	2,058,752	353,741	3,280	1	8
31	March	2,039,834	224,541	3,023	15	8
32	April	1,892,057	284,490	2,754	17	13
33	May	1,947,273	275,902	3,329	31	17
34	June	2,259,402	493,256	3,364	21	17
35	July	2,137,109	164,378	3,729	27	18
36	August	2,372,186	416,062	3,970	24	19
37	September	1,964,275	154,035	3,846	5	15
38	October	1,714,451	96,798	3,172	3	18
39	November	1,911,535	170,345	3,101	28	8
40	December	2,037,536	227,483	3,071	14	8
41	Total	24,564,645	3,190,070			

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Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: MonthlyPeakLoad

Indiana Jurisdictional Split of Peak Volumes

Month	**Volume**
Jan	**2,629**
Feb	**2,794**
Mar	**2,577**
Apr	**2,345**
May	**2,792**
Jun	**2,805**
Jul	**3,133**
Aug	**3,293**
Sep	**3,212**
Oct	**2,684**
Nov	**2,649**
Dec	**2,631**

Michigan Jurisdictional Split of Peak Volumes

Month	**Volume**
Jan	**470**
Feb	**486**
Mar	**446**
Apr	**409**
May	**537**
Jun	**559**
Jul	**596**
Aug	**677**
Sep	**634**
Oct	**488**
Nov	**452**
Dec	**440**

(b) Concept: MonthlyPeakLoad

Jurisdictional Split of Peak Volumes

Month **Volume**

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

Steam Electric Generating Plant Statistics

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
9. Items under Cost of Plant are based on USofA accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Line No.	Item (a)	Plant Name: Donald C Cook Plant	Plant Name: ROCKPORT TOTAL I&M	Plant Name: ROCKPORT TOTAL PLANT	Plant Name: ROCKPORT UNIT 1 I&M	Plant Name: ROCKPORT UNIT 2 I&M
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Nuclear	Steam	Steam [(a)]	Steam	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional	Conventional	Conventional	Conventional
3	Year Originally Constructed	1975	1984	1984	1984	1989
4	Year Last Unit was Installed	1978	1989	1989	1984	1989
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	2,255	1,310	2,620	660	650
6	Net Peak Demand on Plant - MW (60 minutes)	2,304	1,240	2,480	631	650
7	Plant Hours Connected to Load	8,760	3,253	3,253	2,416	2,255
8	Net Continuous Plant Capability (Megawatts)	0	0	0	0	0
9	When Not Limited by Condenser Water	2,296	1,310	2,620	660	650
10	When Limited by Condenser Water	2,181	1,309	2,619	659	650
11	Average Number of Employees	982	0	164	0	0
12	Net Generation, Exclusive of Plant Use - kWh	18,642,410,000	1,383,967,500	2,767,935,000	704,318,000	679,649,500
13	Cost of Plant: Land and Land Rights	1,879,588	6,538,036	13,046,749	6,470,266	67,770
14	Structures and Improvements	473,005,941	131,081,927	311,168,084	99,132,593	31,949,334
15	Equipment Costs	3,158,297,964	1,129,576,336	2,795,352,967	817,655,273	311,921,063
16	Asset Retirement Costs	496,814,452	25,434,118	50,844,963	12,717,059	12,717,059
17	Total cost (total 13 thru 20)	4,129,997,945	1,292,630,417	3,170,412,763	935,975,191	356,655,226
18	Cost per KW of Installed Capacity (line 17/5) Including	1,831.4847	986.7408	1,210.0812	1,418.1442	548.7003
19	Production Expenses: Oper, Supv, & Engr	12,369,910	4,550,680	8,307,453	2,680,530	1,870,150
20	Fuel	99,235,736	55,031,680	110,060,433	28,393,142	26,638,538
21	Coolants and Water (Nuclear Plants Only)	5,271,579				
22	Steam Expenses	11,722,657	11,208,981	23,267,770	5,472,905	5,736,076
23	Steam From Other Sources					
24	Steam Transferred (Cr)					
25	Electric Expenses	5,346,518	1,356,658	2,102,960	958,664	397,994
26	Misc Steam (or Nuclear) Power Expenses	78,272,038	3,997,008	7,076,803	1,616,759	2,380,249
27	Rents		16,325	21,267	14,884	1,441
28	Allowances		3,011,738	3,011,738	2,952,358	59,380
29	Maintenance Supervision and Engineering	3,043,916	1,709,468	3,417,174	854,365	855,103
30	Maintenance of Structures	4,540,865	973,127	1,910,058	493,190	479,937
31	Maintenance of Boiler (or reactor) Plant	86,119,652	6,229,026	12,481,442	3,594,851	2,634,175
32	Maintenance of Electric Plant	18,474,235	3,272,263	6,451,548	1,970,081	1,302,182
33	Maintenance of Misc Steam (or Nuclear) Plant	23,682,415	796,987	1,593,582	406,306	390,681
34	Total Production Expenses	348,079,521	92,153,941	179,702,228	49,408,035	42,745,906
35	Expenses per Net kWh	0.0187	0.0666	0.0649	0.0702	0.0629

35	**Plant Name**	Donald C Cook Plant	ROCKPORT TOTAL I&M	ROCKPORT TOTAL I&M	ROCKPORT TOTAL PLANT	ROCKPORT TOTAL PLANT
36	Fuel Kind	Nuclear	Coal	Oil	Coal	Oil
37	Fuel Unit		t	bbl	t	bbl
38	Quantity (Units) of Fuel Burned		850,625	30,794	1,701,250	61,587
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)		8,652	137,489	8,652	137,489
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year		54.843	121.318	54.843	121.318
41	Average Cost of Fuel per Unit Burned		53.447	132.035	53.447	132.035
42	Average Cost of Fuel Burned per Million BTU	0.505	3.089	23	3.089	23
43	Average Cost of Fuel Burned per kWh Net Gen	0.005	0.033		0.033	
44	Average BTU per kWh Net Generation	10,535	10,349		10,349	

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: PlantKind

The Rockport Plant is a two unit coal fired generating facility. Unit 1 is jointly owned and Unit 2 is jointly leased by the Respondent and AEP Generating Company thru December 7th 2022. Unit 2 was jointly purchased with AEP Generating Company beginning December 8th, 2022. Column (b) represents Respondent's 50% share of Unit 1 and column (c) represents Respondent's 50% share of Unit 2. Column (d) represents Respondent's total share of Rockport Plant and column (e) represents Total Rockport owned and leased by Respondent and AEP Generating Company.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

Hydroelectric Generating Plant Statistics

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Kind of Plant (Run-of-River or Storage)	
2	Plant Construction type (Conventional or Outdoor)	
3	Year Originally Constructed	
4	Year Last Unit was Installed	
5	Total installed cap (Gen name plate Rating in MW)	
6	Net Peak Demand on Plant-Megawatts (60 minutes)	
7	Plant Hours Connect to Load	
8	**Net Plant Capability (in megawatts)**	
9	(a) Under Most Favorable Oper Conditions	
10	(b) Under the Most Adverse Oper Conditions	
11	Average Number of Employees	
12	Net Generation, Exclusive of Plant Use - kWh	
13	**Cost of Plant**	
14	Land and Land Rights	
15	Structures and Improvements	
16	Reservoirs, Dams, and Waterways	
17	Equipment Costs	
18	Roads, Railroads, and Bridges	
19	Asset Retirement Costs	
20	Total cost (total 13 thru 20)	
21	Cost per KW of Installed Capacity (line 20 / 5)	
22	**Production Expenses**	
23	Operation Supervision and Engineering	
24	Water for Power	
25	Hydraulic Expenses	
26	Electric Expenses	
27	Misc Hydraulic Power Generation Expenses	
28	Rents	
29	Maintenance Supervision and Engineering	
30	Maintenance of Structures	
31	Maintenance of Reservoirs, Dams, and Waterways	
32	Maintenance of Electric Plant	
33	Maintenance of Misc Hydraulic Plant	
34	Total Production Expenses (total 23 thru 33)	
35	Expenses per net kWh	

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Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

Pumped Storage Generating Plant Statistics

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on Line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	0
6	Plant Hours Connect to Load While Generating	0
7	Net Plant Capability (in megawatts)	0
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - kWh	0
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	0
12	**Cost of Plant**	
13	Land and Land Rights	
14	Structures and Improvements	0
15	Reservoirs, Dams, and Waterways	0
16	Water Wheels, Turbines, and Generators	0
17	Accessory Electric Equipment	0
18	Miscellaneous Powerplant Equipment	0
19	Roads, Railroads, and Bridges	0
20	Asset Retirement Costs	0
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	**Production Expenses**	
24	Operation Supervision and Engineering	0
25	Water for Power	0
26	Pumped Storage Expenses	0
27	Electric Expenses	0
28	Misc Pumped Storage Power generation Expenses	0
29	Rents	0
30	Maintenance Supervision and Engineering	0
31	Maintenance of Structures	0
32	Maintenance of Reservoirs, Dams, and Waterways	0
33	Maintenance of Electric Plant	0
34	Maintenance of Misc Pumped Storage Plant	0
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per kWh (line 37 / 9)	
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0

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Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel Production Expenses (i)	Production Expenses: Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)
1	Berrien Springs	1908	7.20	6.0	31,395	17,187,524	2,387,156	357,916		277,100		
2	Buchanan	1919	4.10	2.8	15,338	8,337,789	2,033,607	223,125		215,818		
3	Constantine	1921	1.20	0.9	3,985	3,387,259	2,822,716	164,510		86,868		
4	Elkhart	1913	3.44	2.3	11,063	10,461,956	3,041,266	198,888		505,928		
5	Mottville	1923	1.68	1.4	6,097	5,348,558	3,183,665	114,466		253,820		
6	Twin Branch	1904	4.80	3.8	18,240	14,496,788	3,020,164	315,930		401,423		
7	Deer Creek	2015	2.50	2.5	3,268	6,415,804	2,566,322	(4,192)		48,723		
8	Olive	2016	5.00	5.5	8,025	12,062,064	2,412,413	(4,095)		96,158		
9	St. Joseph	2020	20.00	19.9	32,397	38,069,838	1,903,492	(4,576)		101,118		
10	Twin Branch Solar	2016	2.60	2.8	3,798	7,016,092	2,698,497	(2,722)		22,103		
11	Watervliet	2016	4.60	4.8	6,562	11,981,072	2,604,581	(6,854)		33,271		

Line No.	Generation Type (m)
1	Hydro
2	Hydro
3	Hydro
4	Hydro
5	Hydro
6	Hydro
7	Solar
8	Solar
9	Solar
10	Solar
11	Solar

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) should include MWHs delivered/provided to a genera ancillary services.
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify and (o), report fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power.
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generator whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)	MWHs Sold (k)	Revenues from Energy Storage Operations (l)	Power Purchased for Storage Operations (555.1) (Dollars) (m)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (n)	Othe Cost Associ with S Genera Pow (Dolla (o)
35	TOTAL			0	0	0	0	0	0	0	0	0	0	0	

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 Kw.
2. In columns (a), (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.
4. In column (e), report operation expenses excluding fuel, (f), maintenance expenses, (g) fuel costs for storage operations and (h) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined.
5. If any other expenses, report in column (i) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	Project Cost (d)	BALANCE AT BEGINNING OF YEAR				
					Operations (Excluding Fuel used in Storage Operations) (e)	Maintenance (f)	Cost of fuel used in storage operations (g)	Account No. 555.1, Power Purchased for Storage Operations (h)	Other Expenses (i)
1	TOTAL			0	0	0	0	0	0
36	TOTAL								

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
5. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.
6. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
7. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
8. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designated (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) - (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)	Size of Conductor and Material (i)
1	STATE OF INDIANA	STATE OF INDIANA							
2	6128 DUMONT	JEFFERSON	765.00	765.00	3	202.50	0	1	4-954 KCM
3	6136 DUMONT	WILTON CENTER	765.00	765.00	3	63.00	0	1	4-954 KCM
4	6141 DUMONT	MARYSVILLE	765.00	765.00	3	99.38	0	1	4-954 KCM
5	6215 D.C. COOK	DUMONT	765.00	765.00	3	20.00	0	1	4-954 KCM
6	6223 ROCKPORT	JEFFERSON	765.00	765.00	3	111.00	0	1	4-1351 KCM
7	6224 ROCKPORT	SULLIVAN	765.00	765.00	3	97.00	0	1	4-1351 KCM
8	6226 JEFFERSON	WEST	765.00	765.00		0.00	0	0	
9	6236 HANGING ROCK	JEFFERSON	765.00	765.00	3	1.00	0	1	4-1351 KCM
10	0675 TANNERS CREEK	SORENSON	345.00	345.00	3	135.58	0	2	1275 KCM
11	0675 TANNERS CREEK	SORENSON	345.00	345.00	1	0.42	0	2	1414 KCM
12	0676 SORENSON	EAST LIMA	345.00	345.00	3	29.68	0	1	1275 KCM
13	0676 SORENSON	EAST LIMA	345.00	345.00	1	0.27	0	1	2-954 KCM
14	0677 BREED	DEQUINE EAST	345.00	345.00	3	46.44	0	2	1414 KCM
15	0677 BREED	DEQUINE EAST	345.00	345.00	3	45.13	0	1	1414 KCM
16	0677 BREED	DEQUINE EAST	345.00	345.00	3	0.65	0	2	2-954 KCM
17	0677 BREED	DEQUINE EAST	345.00	345.00	1	0.18	0	2	1414 KCM
18	0677 BREED	DEQUINE EAST	345.00	345.00	1	3.77	0	2	2303 KCM
19	0677 BREED	DEQUINE EAST	345.00	345.00	1	0.08	0	2	2-2303 KCM
20	0678 DEQUINE	OLIVE	345.00	345.00	3	13.31	0	2	2303 KCM
21	0678 DEQUINE	OLIVE	345.00	345.00	3	54.19	0	2	1,414KCM
22	0678 DEQUINE	OLIVE	345.00	345.00	1	0.50	0	2	2156 KCM
23	0678 DEQUINE	OLIVE	345.00	345.00	1	0.14	0	2	2,303 KCM
24	0678 DEQUINE	OLIVE	345.00	345.00	1	0.45	0	2	2-954 KCM
25	0679 SORENSON	OLIVE	345.00	345.00	3	77.90	0	1	1272 KCM
26	0679 SORENSON	OLIVE	345.00	345.00	1	0.10	0	1	1272 KCM
27	0680 OLIVE	GOODINGS GROVE	345.00	345.00	3	41.00	0	2	1414 KCM
28	0683 DESOTO	JCT TOWER (MAR. CO)	345.00	345.00	3	53.00	6	1	2-954 KCM
29	0684 TANNERS CREEK	JUNCTION TOWER	345.00	345.00	3	79.98	0	1	2-954 KCM
30	0684 TANNERS CREEK	JUNCTION TOWER	345.00	345.00	2	0.02	0	1	2-954 KCM
31	0685 HANNA	JUNCTION TOWER	345.00	345.00	3	5.63	0	0	2-954 KCM
32	0687 TANNERS CREEK	MIAMI FORT	345.00	345.00	3	0.28	0	2	2-954 KCM
33	0688 EUGENE	SIDNEY	345.00	345.00	1	0.20	0	1	1414 KCM
34	0689 SORENSON-OLIVE	TWIN BRANCH	345.00	345.00	3	11.00	0	2	1563 KCM
35	0690 BREED	CIPSCO	345.00	345.00	3	0.94	0	1	2-1024 KCM
36	0690 BREED	CIPSCO	345.00	345.00	3	0.02	0	1	2-1351.5 KCM
37	0691 BREED	PETERSBURG	345.00	345.00	3	0.70	0	1	2-954 KCM
38	0691 BREED	PETERSBURG	345.00	345.00	1	0.15	0	1	2-1351.5 KCM
39	0731 Varner	South Butler	345.00	345.00	1	0.60	0	1	2-954 KCM
40	0734 Dunton Lake Extension		345.00	345.00	3	0.25	0	2	2-954 KCM
41	6118 ROBISON PARK	SORENSON-EAST LIMA	345.00	345.00	3	22.66	0	2	1414 KCM
42	6118 ROBISON PARK	SORENSON-EAST LIMA	345.00	345.00	1	0.34	0	1	1414 KCM
43	6119 COOK	OLIVE	345.00	345.00	3	4.00	0	2	2-954 KCM
44	6122 DUMONT	OLIVE	345.00	345.00	3	14.52	0	2	2-954 KCM
45	6122 DUMONT	OLIVE	345.00	345.00	1	0.60	0	1	2-954 KCM

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
46	6123 DUMONT	TWIN BRANCH	345.00	345.00	3	17.00	0	2	2-954 KCM
47	6125 ROBISON PARK	EAST	345.00	345.00		0.00	0	0	
48	6133 DUMONT	BABCOCK	345.00	345.00	3	9.00	0	1	2-954 KCM
49	6145 TWIN BRANCH	COOK-ROB PARK JCT	345.00	345.00	3	6.00	0	2	2-954 KCM
50	6147 COOK	ROBISON PARK	345.00	345.00	3	67.41	0	2	2-954 KCM
51	6147 COOK	ROBISON PARK	345.00	345.00	1	0.41	0	0	2-954 KCM
52	6148 JACKSON ROAD	SORENSON-OLIVE	345.00	345.00	3	4.00	0	2	2303 KCM
53	6213 COOK-ROB-PARK JCT	ARGENTA	345.00	345.00	3	2.00	0	2	2-954 KCM
54	6237 JACKSON ROAD	WEST	345.00	345.00		0.00	0	0	
55	6240 TWIN BRANCH	SUBSTATION CORRIDOR	345.00	345.00		0.00	0	0	
56	6256 BREED	SULLIVAN	345.00	345.00	3	0.48	0	2	1351.5 KCM
57	6256 BREED	SULLIVAN	345.00	345.00	3	0.75	0	1	1351.5 KCM
58	6256 BREED	SULLIVAN	345.00	345.00	1	0.29	0	1	1351.5 KCM
59	6259 COLLINGWOOD	SOUTH BUTLER	345.00	345.00	1	14.65	0	1	2-954 KCM
60	6232 Arnold Hogan	Kenmore	34.00	138.00	1	1.26	0	2	795 KCM
61	0604 TWIN BRANCH	ROBISON PARK	138.00	138.00	3	8.50	0	2	397.5 KCM
62	0604 TWIN BRANCH	ROBISON PARK	138.00	138.00	1	0.28	0	2	1233.6 KCM
63	0605 SOUTH BEND	MICHIGAN CITY	138.00	138.00	3	0.00	0	1	397.5 KCM
64	0606 ROBISON PARK	HAVILAND	138.00	138.00	3	0.00	0	2	397.5 KCM
65	0606 ROBISON PARK	HAVILAND	138.00	138.00	1	0.00	0	0	1233.6 KCM
66	0607 ROBISON PARK	DEER CREEK	138.00	138.00	1	0.12	0	2	1590 KCM
67	0607 ROBISON PARK	DEER CREEK	69.00	138.00	1	0.00	1	1	1033.5 KCM
68	0608 DEER CREEK	KOKOMO	138.00	138.00	3	0.00	0	1	336.4 KCM
69	0608 DEER CREEK	KOKOMO	138.00	138.00	3	1.88	0	1	636 KCM
70	0608 DEER CREEK	KOKOMO	138.00	138.00	1	0.00	0	1	336.4 KCM
71	0609 CONCORD TAP		138.00	138.00	3	4.00	0	2	397.5 KCM
72	0613 TWIN BRANCH	JACKSON ROAD	138.00	138.00	3	8.00	0	2	447 KCM
73	0614 LINCOLN TAP		138.00	138.00	3	4.00	0	2	397.5 KCM
74	0615 TWIN BRANCH	ROBISON PARK	138.00	138.00	3	65.83	0	1	477 KCM
75	0616 DEER CREEK	DELAWARE	138.00	138.00	3	2.40	0	2	397.5 KCM
76	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	3	48.81	0	2	397.5 KCM
77	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	4	0.84	0	2	2,000KCM
78	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	2	0.11	0	2	397.5 KCM
79	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	1	0.75	0	2	397.5 KCM
80	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	1	0.20	0	2	556.5 KCM
81	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	2	1.02	0	1	795 KCM
82	0619 MADISON	NEW CASTLE	138.00	138.00	3	6.00	1	1	795 KCM
83	0620 TANNERS CREEK	MADISON	138.00	138.00	3	82.00	0	2	636 KCM
84	0620 TANNERS CREEK	MADISON	138.00	138.00	1	0.15	0	1	795 KCM
85	0622 JACKSON ROAD	OLIVE	138.00	138.00	3	16.29	1	1	556.5 KCM
86	0622 JACKSON ROAD	OLIVE	138.00	138.00	1	0.47	0	1	556.5 KCM
87	0623 MADISON	PENDLETON	138.00	138.00	2	5.00	0	1	477 KCM
88	0624 DRAGOON TAP		138.00	138.00	3	2.00	0	1	795 KCM

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designated (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) - (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)	Size of Conductor and Material (i)
89	0625 TANNERS CREEK	COLLEGE CORNER	138.00	138.00	3	51.90	0	2	636 KCM
90	0625 TANNERS CREEK	COLLEGE CORNER	138.00	138.00	1	0.37	0	2	636 KCM
91	0626 COLLEGE CORNER	RANDOLPH	138.00	138.00	2	34.58	0	1	556.5 KCM
92	0626 COLLEGE CORNER	RANDOLPH	138.00	138.00	1	1.07	0	1	556.5 KCM
93	0626 COLLEGE CORNER	RANDOLPH	138.00	138.00	2	3.34	0	0	556.5 KCM
94	0627 RANDOLPH	JAY	138.00	138.00	2	23.69	0	1	556.5 KCM
95	0627 RANDOLPH	JAY	138.00	138.00	1	0.32	0	0	556.5 KCM
96	0628 MCKINLEY TAP		138.00	138.00	3	0.85	0	2	300 KCM CU
97	0628 MCKINLEY TAP		138.00	138.00	1	0.15	0	2	300 KCM CU
98	0629 JAY	LINCOLN	138.00	138.00	2	0.00	0	1	556.5 KCM
99	0629 JAY	LINCOLN	138.00	138.00	3	0.00	0	1	1033.5 KCM
100	0630 NEW CARLISLE	MAPLE	138.00	138.00	2	1.00	0	1	397.5 KCM
101	6104 SORENSON	TWIN BRANCH	138.00	138.00	3	61.14	0	1	447 KCM
102	6104 SORENSON	TWIN BRANCH	138.00	138.00	1	3.63	0	1	556.5 KCM
103	6104 SORENSON	TWIN BRANCH	138.00	138.00	1	0.03	0	1	795 KCM
104	0632 SORENSON	DEVILS HOLLOW	138.00	138.00	3	0.00	0	0	556.5 KCM
105	0634 DEER CREEK	MULLIN	138.00	138.00	2	15.70	0	1	556.5 KCM
106	0635 PENDLETON	MULLIN	138.00	138.00	2	14.10	0	1	556.5 KCM
107	0635 PENDLETON	MULLIN	138.00	138.00	3	0.40	0	1	556.5 KCM
108	0635 PENDLETON	MULLIN	138.00	138.00	1	0.72	0	1	556.5 KCM
109	0636 DEER CREEK	FISHER BODY	138.00	138.00	3	5.04	0	2	397.5 KCM
110	0637 TWIN BRANCH	EAST ELKHART	138.00	138.00	3	17.00	1	2	556.5 KCM
111	0638 GRANT	FISHER BODY	138.00	138.00	3	0.00	1	1	397.5 KCM
112	0639 ROBISON PARK	AUBURN	138.00	138.00	1	0.00	0	1	556.5 KCM
113	0641 DESOTO	MEDFORD	138.00	138.00	1	0.15	0	2	795 KCM
114	0641 DESOTO	MEDFORD	138.00	138.00	3	6.86	0	2	556.5 KCM
115	0642 OLIVE	HICKORY CREEK	138.00	138.00	3	2.99	2	1	556.5 KCM
116	0645 COREY TAP		138.00	138.00	2	4.00	0	1	477 KCM
117	0646 OLIVE	NEW CARLISLE	138.00	138.00	3	2.00	0	1	556.5 KCM
118	0647 OLIVE	SOUTH BEND	138.00	138.00	3	15.97	0	2	397.5 KCM
119	0648 MEDFORD TAP		138.00	138.00	1	0.13	0	2	556.5 KCM
120	0648 MEDFORD TAP		138.00	138.00	3	7.94	0	2	556.5 KCM
121	0723 SPY RUN STATION		138.00	138.00	4	0.00	0	1	3.5IN OD
122	0730 Varner	Wilmington	138.00	138.00	1	0.83	0	1	795 KCM
123	0742 Deptmer Sw	Harber (REMC)	69.00	138.00	1	0.06	0	1	795 KCM
124	6101 WESTINGHOUSE TAP		138.00	138.00	3	2.00	0	2	556.5 KCM
125	6102 MILAN TAP		138.00	138.00	3	6.00	0	2	397.5 KCM
126	6103 MILAN	GOODRICH	138.00	138.00	3	1.00	0	2	397.5 KCM
127	6105 DESOTO	JAY	138.00	138.00	2	10.31	0	1	2-556.5 KCM
128	6105 DESOTO	JAY	138.00	138.00	3	2.25	0	1	2-556.5 KCM
129	6106 DESOTO	DEER CREEK-DELAWARE	138.00	138.00	3	7.21	0	2	636 KCM
130	6106 DESOTO	DEER CREEK-DELAWARE	138.00	138.00	1	1.20	0	0	636 KCM
131	6107 DARDEN TAP		138.00	138.00	2	0.94	0	1	336.4 KCM
132	6109 ROBISON PARK	RICHLAND	138.00	138.00	2	13.76	0	1	636 KCM

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
133	6109 ROBISON PARK	RICHLAND	138.00	138.00	1	0.05	0	0	1233.6 KCM
134	6109 ROBISON PARK	RICHLAND	138.00	138.00	3	4.49	0	0	636 KCM
135	6110 WESTINGHOUSE	23RD STREET	138.00	138.00	3	0.00	0	2	556.5 KCM
136	6111 KANKAKEE	WEST SIDE	138.00	138.00	1	2.00	0	1	636 KCM
137	6113 INDUSTRIAL PARK		138.00	138.00	3	3.00	0	2	745 KCM
138	6114 OLIVE	MICHIGAN CITY	138.00	138.00	3	1.94	1	1	636 KCM
139	6115 HUMMEL CREEK	VAN BUREN	138.00	138.00	3	6.00	0	2	795 KCM
140	6130 HUMMEL CREEK	TOWER 70, GREENTOWN	138.00	138.00		0.00	0	0	
141	6116 SOUTH ELWOOD TAP		138.00	138.00	1	3.07	0	1	556.5 KCM
142	6117 PENDLETON	FALL CREEK	138.00	138.00	3	10.70	0	2	795 KCM
143	6117 PENDLETON	FALL CREEK	138.00	138.00	1	0.07	0	2	795 KCM
144	6121 ROBISON PARK	LINCOLN	138.00	138.00	3	7.84	0	1	795 KCM
145	6121 ROBISON PARK	LINCOLN	138.00	138.00	1	0.02	0	0	1233.6 KCM
146	6126 CONCORD	EAST ELKHART	138.00	138.00	3	11.00	0	1	795 KCM
147	6129 GREENTOWN-GRANT	HUMMEL CREEK	138.00	138.00	3	21.00	0	1	795 KCM
148	6131 INDUSTRIAL PARK	MC KINLEY	138.00	138.00	1	4.96	0	1	795 KCM
149	6132 CROSS STREET TAP	JUNCTION TOWER #88	138.00	138.00	1	4.00	0	1	795 KCM
150	6134 LINCOLN	ANTHONY	138.00	138.00	1	3.00	0	1	795 KCM
151	6135 WAYNEDALE TAP		138.00	138.00	3	0.00	0	2	795 KCM
152	6138 JACKSON ROAD	SOUTH SIDE	138.00	138.00	1	2.00	0	1	795 KCM
153	6142 ALBION	KENDALLVILLE	138.00	138.00	3	10.00	0	1	795 KCM
154	6150 SOUTHSIDE	SOUTH BEND	138.00	138.00	1	6.07	0	1	795 KCM
155	6219 DELCO BATTERY TAP		138.00	138.00	1	0.94	0	2	795 KCM AA
156	6220 FALL CREEK	MADISON-NEW CASTLE	138.00	138.00	3	1.10	0	2	795 KCM
157	6220 FALL CREEK	MADISON-NEW CASTLE	138.00	138.00	1	0.15	0	2	795 KCM
158	6225 INDUSTRIAL PARK	SPY RUN	138.00	138.00	1	4.10	0	1	1033 KCM
159	6266 WALLEN		138.00	138.00	1	0.22	0	1	1033.5 KCM
160	6234 CABOT TAP/CR 4	EAST ELKHART	138.00	138.00	1	0.13	0	1	556.5 KCM
161	6238 SORENSON	MCKINLEYTOWER	138.00	138.00	3	2.82	0	2	795 KCM
162	6238 SORENSON	MCKINLEYTOWER	138.00	138.00	1	0.26	0	2	795 KCM
163	6241 KENDALLVILLE TAP	CITY OF AUBURN #5	138.00	138.00	1	14.00	0	1	795 KCM
164	6241 KENDALLVILLE TAP	CITY OF AUBURN #5	138.00	138.00	2	14.00	0	1	795 KCM
165	6242 AUBURN	CITY OF AUBURN #5	138.00	138.00	1	2.00	0	1	795 KCM
166	6245 LAPORTE JCT	LIQUID CARBONICS	138.00	138.00	1	4.76	0	1	795 KCM
167	6245 LAPORTE JCT	LIQUID CARBONICS	138.00	138.00	1	0.23	0	0	1033.5 KCM
168	6246 LAPORTE JCT	AIRCO	138.00	138.00	1	0.72	0	1	795 KCM
169	6248 ELCONA TAP	CONC-DUN-E-ELK	138.00	138.00	1	2.00	0	1	795 KCM
170	6249 ALLEN	LINCOLN	138.00	138.00	3	4.90	0	2	1033 KCM
171	6249 ALLEN	LINCOLN	138.00	138.00	1	0.09	0	2	1233.6 KCM

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
172	6250 ALLEN	ADAMS/HILLCREST	138.00	138.00	3	4.92	0	2	1033 KCM
173	6250 ALLEN	ADAMS/HILLCREST	138.00	138.00	1	0.07	0	2	1233.6 KCM
174	6251 OLIVE	EDISON	138.00	138.00	3	1.00	0	2	795 KCM
175	6253 TRIER RD TAP		138.00	138.00	1	0.00	0	1	795 KCM
176	6258 KENZIE CREEK	TWIN BRANCH	138.00	138.00	3	0.00	0	2	1033 KCM
177	6260 WILMINGTON TAP		138.00	138.00	1	0.20	9	1	2-954 KCM
178	6229 DUNLAP NORTH TAP		34.00	138.00	1	2.00	0	2	795 KCM
179	6140 INDIANA-PURDUE		34.00	138.00	1	0.00	0	2	1033 KCM
180	6217 HILLCREST	KINNERK	69.00	138.00	1	3.92	0	1	795 KCM
181	6217 HILLCREST	KINNERK	69.00	138.00	2	0.03	0	1	795 KCM
182	6252 KENDALLVILLE	BIXLER	138.00	138.00	1	2.91	0	1	795 KCM
183	6254 ALLEN/LINCOLN	ALLEN/HILLCREST	138.00	138.00		0.00	0	0	
184	6265 CONCORD	WOLF	138.00	138.00	1	0.77	0	1	336.4 KCM
185	6271 INDALEX TAP/CR 4	EAST ELKHART	138.00	138.00	1	1.09	0	1	556.5 KCM
186	6267 STUDEBAKER	WEST SIDE	138.00	138.00	1	2.57	0	1	954 KCM
187	6270 JONES CREEK	HOGAN	138.00	138.00		5.47	0	1	795 KCM
188	6273 DAWKINS SWITCH	HERBERT MONROE (WVPA)	138.00	138.00	1	0.50	0	1	4/0
189	LINES<132 KV	SYSTEM	69.00	0.00	Various	518.14	72	1	VARIOUS
190	STATE OF MICHIGAN	STATE OF MICHIGAN	0.00	0.00		0.00	0	0	
191	6216 D.C. COOK	DUMONT	765.00	765.00	3	16.00	0	1	4-954 KCM
192	6120 COOK	PALISADES	345.00	345.00	3	41.78	0	2	2-954 KCM
193	6120 COOK	PALISADES	345.00	345.00	1	0.23	0	0	2-954 KCM
194	6120 COOK	PALISADES	345.00	345.00	1	0.21	0	0	2-1158.4 KCM
195	6143 D.C. COOK	OLIVE-PALISADES	345.00	345.00	3	5.00	0	2	2-954 KCM
196	6144 TWIN BRANCH	COOK-ROB PARK JCT	345.00	345.00	3	0.00	0	2	2-954 KCM
197	6151 COOK	OLIVE	345.00	345.00		0.00	0	0	
198	6152 COOK	ROBISON PARK	345.00	345.00		0.00	0	0	
199	6146 D.C. COOK	ROBISON PARK	345.00	345.00	3	36.80	0	2	2-954 KCM
200	6146 D.C. COOK	ROBISON PARK	345.00	345.00	3	0.09	0	0	954 KCM
201	6214 COOK-ROB PARK	ARGENTA	345.00	345.00	3	28.78	0	2	2-954 KCM
202	6214 COOK-ROB PARK	ARGENTA	345.00	345.00	1	0.22	0	2	2-954 KCM
203	6221 D.C. COOK	OLIVE-PALISADES	345.00	345.00	3	5.00	0	2	2-954 KCM
204	6263 BARODA TAP		138.00	138.00		0.00	0	0	
205	0601 TWIN BRANCH	RIVERSIDE	138.00	138.00	3	0.00	0	2	397.5KCM & 1033.5
206	0601 TWIN BRANCH	RIVERSIDE	138.00	138.00	1	0.00	0	2	397.5KCM & 1033.5
207	0610 AUTO SPECIALTIES		138.00	138.00		0.00	0	0	
208	0621 TWIN BRANCH - R	HICKORY CREEK	138.00	138.00	3	5.00	0	2	397.5 KCM
209	0643 OLIVE	HICKORY CREEK	138.00	138.00	3	23.10	2	1	556.5 KCM
210	0644 RIVERSIDE	HARTFORD	138.00	138.00	2	14.22	0	1	397.5 KCM
211	0644 RIVERSIDE	HARTFORD	138.00	138.00	3	2.11	0	0	397.5 KCM
212	0649 COREY TAP		138.00	138.00	2	12.12	0	1	477 KCM
213	0649 COREY TAP		138.00	138.00	1	0.13	0	1	477 KCM
214	6150 SOUTHSIDE	SOUTH BEND	138.00	138.00	1	6.23	0	1	795 KCM

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
215	6108 RIVERSIDE	OLIVE-HICKORY CREEK	138.00	138.00	1	6.00	0	1	636 KCM
216	6124 BENTON HARBOR	RIVERSIDE-HARTFORD	138.00	138.00	3	1.00	0	2	795 KCM
217	6137 EDGEWATER TAP		138.00	138.00	1	0.76	0	1	556.5 KCM
218	6149 HARTFORD	COREY	138.00	138.00	1	18.97	0	1	795 KCM
219	6149 HARTFORD	COREY	138.00	138.00		0.00	2	1	795 KCM
220	6149 HARTFORD	COREY	138.00	138.00	2	12.88	0	1	795 KCM
221	6149 HARTFORD	COREY	138.00	138.00		0.00	1	1	1033.5 KCM
222	6149 HARTFORD	COREY	138.00	138.00	1	1.34	0	1	1033.5 KCM
223	6149 HARTFORD	COREY	138.00	138.00	1	0.53	0	2	1033.5 KCM
224	6218 MOTTVILLE TAP		138.00	138.00	1	1.00	0	1	795 KCM
225	6219 DELCO BATTERY TAP		138.00	138.00	1	0.50	0	2	795 KCM
226	6219 DELCO BATTERY TAP		138.00	138.00	1	0.15	0	1	795 KCM
227	6255 KENZIE CREEK	VALLEY	138.00	138.00	1	20.00	0	1	1033 KCM
228	6257 KENZIE CREEK	T B/R'SIDE/HICK CR	138.00	138.00	3	0.00	0	0	795 KCM
229	6261 FLATBUSH TAP		138.00	138.00		1.00	0	1	
230	6262 WEST ST TAP		138.00	138.00		1.00	0	2	
231	6700 GM HYDRAMATIC		138.00	138.00	3	2.00	0	2	795 KCM
232	6227 NICKERSON	TOWER #13A	138.00	138.00		0.00	0	0	
233	6268 SAUK TRAIL		138.00	138.00	1	1.60	0	0	1033.5KCM 45/7ACR
234	LESS THAN 132 KV LINES		69.00	0.00	Various	375.90	12	0	VARIOUS
235	Line cost and expense are	not available by individual							
236	transmission line.	Total shown in column j-p							
36	TOTAL					3,280	112	292	

Line No.	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
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	Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
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Line No.	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
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Line No.	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
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235	77,099,012	822,804,734	899,903,745	352,065	12,080,849		12,432,914
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36	77,099,012	822,804,734	899,903,745	352,065	12,080,849	0	12,432,914

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)	Size (h)	Specification (i)	Configuration and Spacing (j)	(k)
1	Nothing to Report										
44	TOTAL		0		0	0	0				

Line No.	LINE COST					Construction
	Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(l)	(m)	(n)	(o)	(p)	(q)
1						
44						

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
1	ADAMS (IM) - IN	Transmission		138.00	13.00	0.00	12.50	1	0
2	ADAMS (IM) - IN	Distribution		138.00	69.00	34.00	115.00	1	0
3	ALBION - IN	Distribution		69.00	0.00	0.00	0.00	0	0
4	ALBION - IN	Distribution		138.00	0.00	0.00	0.00	0	0
5	ALBION - IN	Distribution		69.00	12.00	0.00	8.40	1	0
6	ALBION - IN	Transmission		138.00	69.00	12.00	90.00	1	0
7	ALLEN (IM) - IN	Distribution		345.00	137.50	13.80	450.00	1	0
8	ANACONDA - IN	Distribution		34.50	4.00	0.00	3.75	1	0
9	ANCHOR HOCKING (IM) - IN	Distribution		69.00	13.09	0.00	20.00	1	0
10	ANCHOR HOCKING (IM) - IN	Distribution		69.00	2.40	0.00	13.75	2	0
11	ANTHONY - IN	Distribution		138.00	34.00	0.00	112.00	1	0
12	ANTHONY - IN	Distribution		34.50	12.00	0.00	29.38	2	0
13	ANTIVILLE - IN	Distribution		69.00	12.00	0.00	3.65	1	0
14	ARMSTRONG CORK - IN	Distribution		69.00	4.00	0.00	19.88	2	0
15	ARNOLD HOGAN - IN	Distribution		138.00	34.50	0.00	75.00	1	0
16	AUBURN - IN	Transmission		138.00	70.50	36.20	130.00	1	0
17	AUBURN - IN	Distribution		138.00	0.00	0.00	0.00	0	0
18	BEECH ROAD - IN	Transmission		138.00	13.09	0.00	20.00	1	0
19	BERNE - IN	Transmission		69.00	0.00	0.00	0.00	0	0
20	BERNE - IN	Transmission		69.00	12.00	0.00	20.00	1	0
21	BIG RUN - IN	Transmission		69.00	0.48	0.00	2.50	1	0
22	BIXLER - IN	Distribution		138.00	13.09	0.00	20.00	1	0
23	BLAINE STREET - IN	Distribution		34.50	13.00	0.00	20.00	1	0
24	BLUFF POINT - IN	Distribution		69.00	13.00	0.00	5.60	1	0
25	BLUFF POINT - IN	Distribution		69.00	0.00	0.00	0.00	0	0
26	BLUFFTON (IM) - IN	Distribution		69.00	0.00	0.00	0.00	0	0
27	BUTLER (IM) - IN	Distribution		69.00	13.00	0.00	20.00	1	0
28	BUTLER (IM) - IN	Transmission		69.00	0.00	0.00	0.00	0	0
29	CALVERT - IN	Transmission		138.00	13.09	0.00	20.00	1	0
30	CAPITAL AVENUE - IN	Transmission		138.00	13.09	0.00	12.00	1	0
31	CARROLL - IN	Transmission		34.50	13.00	0.00	1.50	3	0
32	CHURUBUSCO - IN	Transmission		34.50	13.00	0.00	10.50	1	0
33	CLEVELAND - IN	Transmission		138.00	13.09	0.00	12.00	1	0
34	Clipper - IN	Transmission		69.00	13.09	0.00	6.25	1	0
35	COLONY BAY - IN	Transmission		69.00	13.00	0.00	22.40	1	0
36	COLONY BAY - IN	Transmission		69.00	12.00	0.00	20.00	1	0
37	CONANT - IN	Transmission		34.50	12.00	0.00	22.40	1	0
38	CONCORD - IN	Transmission		138.00	70.50	36.20	130.00	1	0
39	CONCORD - IN	Transmission		138.00	13.09	0.00	22.40	1	0
40	CONCORD - IN	Transmission		138.00	0.00	0.00	0.00	0	0
41	CONCORD - IN	Distribution		138.00	13.09	0.00	22.40	1	0
42	COUNTRYSIDE - IN	Distribution		138.00	12.47	0.00	20.00	1	0
43	COUNTY LINE (IM) - IN	Transmission		138.00	13.09	0.00	20.00	1	0
44	COUNTY ROAD 4 - IN	Distribution		138.00	13.09	0.00	20.00	1	0
45	CROSS STREET - IN	Distribution		138.00	13.09	0.00	20.00	1	0
46	DALEVILLE - IN	Transmission		138.00	13.09	0.00	20.00	1	0
47	DARDEN ROAD - IN	Transmission		138.00	13.09	0.00	42.40	2	0
48	DECATUR (FTW) - IN	Transmission		69.00	13.00	0.00	20.00	1	0
49	DECATUR (FTW) - IN	Distribution		69.00	0.00	0.00	0.00	0	0
50	DECATUR (FTW) - IN	Distribution		69.00	0.00	0.00	0.00	0	0
51	DEER CREEK - IN	Distribution		34.50	0.00	0.00	0.00	0	0
52	DEER CREEK - IN	Transmission		138.00	69.00	34.00	90.00	1	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
53	DEER CREEK - IN	Transmission		138.00	0.00	0.00	0.00	0	0
54	DEER CREEK - IN	Transmission		138.00	34.50	0.00	75.00	1	0
55	DEER CREEK - IN	Distribution		34.50	13.09	0.00	3.75	1	0
56	DEER CREEK - IN	Distribution		138.00	13.09	0.00	20.00	1	0
57	DELAWARE (IM) - IN	Distribution		138.00	0.00	0.00	0.00	0	0
58	DELAWARE (IM) - IN	Distribution		138.00	0.00	0.00	0.00	0	0
59	DELAWARE (IM) - IN	Distribution		34.50	0.00	0.00	0.00	0	0
60	DELAWARE (IM) - IN	Distribution		138.00	34.00	0.00	125.00	2	0
61	DESOTO - IN	Distribution		345.00	138.00	34.50	675.00	1	0
62	DIEBOLD ROAD - IN	Distribution		69.00	13.00	0.00	20.00	1	0
63	DOOVILLE - IN	Distribution		138.00	13.09	0.00	12.00	1	0
64	DRAGOON - IN	Distribution		138.00	69.00	34.00	84.00	1	0
65	DUMONT - IN	Distribution		765.00	0.00	0.00	0.00	0	0
66	DUNLAP - IN	Transmission		138.00	13.09	0.00	20.00	1	0
67	EAST ELKHART - IN	Transmission		345.00	137.50	13.80	450.00	1	0
68	EAST SIDE (IM) - IN	Distribution		138.00	13.09	0.00	37.40	2	0
69	EGE - IN	Distribution		138.00	34.50	13.00	7.50	1	0
70	ELCONA - IN	Distribution		138.00	13.09	0.00	22.40	1	0
71	ELKHART HYDRO STAT - IN	Distribution		34.50	34.40	4.36	13.75	2	0
72	ELKHART HYDRO STAT - IN	Distribution		34.50	13.09	4.36	13.75	2	0
73	ELLISON ROAD - IN	Transmission		138.00	13.09	0.00	20.00	1	0
74	FARMLAND - IN	Transmission		69.00	13.09	0.00	20.00	1	0
75	FERGUSON - IN	Distribution		69.00	13.00	0.00	20.00	1	0
76	FISHER BODY - IN	Distribution		138.00	13.80	0.00	100.00	2	0
77	FULTON (IM) - IN	Distribution		34.50	13.09	0.00	12.00	1	0
78	GAS CITY - IN	Distribution		34.50	0.00	0.00	0.00	0	0
79	GAS CITY - IN	Distribution		34.50	13.00	0.00	20.00	1	0
80	GASTON - IN	Distribution		138.00	13.09	0.00	20.00	1	0
81	GATEWAY (IM) - IN	Distribution		69.00	0.00	0.00	0.00	0	0
82	GERMAN - IN	Transmission		138.00	13.09	0.00	47.40	2	0
83	GLENBROOK - IN	Transmission		34.50	13.09	0.00	12.00	1	0
84	GLENBROOK - IN	Distribution		34.50	13.00	0.00	20.00	1	0
85	GRABILL - IN	Distribution		138.00	13.09	0.00	20.00	1	0
86	GRANGER - IN	Transmission		138.00	12.47	0.00	20.00	1	0
87	GRANGER - IN	Transmission		138.00	13.09	0.00	20.00	1	0
88	GRANT - IN	Transmission		138.00	34.50	0.00	30.00	1	0
89	GRANT - IN	Transmission		138.00	13.09	0.00	20.00	1	0
90	GREENLEAF - IN	Transmission		34.50	13.09	0.00	20.00	1	0
91	GREENTOWN - IN	Transmission		765.00	0.00	0.00	0.00	0	0
92	HACIENDA - IN	Transmission		138.00	13.09	0.00	45.00	2	0
93	HADLEY - IN	Transmission		69.00	13.00	0.00	40.00	2	0
94	HARLAN - IN	Transmission		69.00	13.09	0.00	12.50	1	0
95	HARPER - IN	Transmission		138.00	13.09	0.00	20.00	1	0
96	HARTFORD CITY - IN	Distribution		69.00	13.00	0.00	20.00	1	0
97	HARVEST PARK - IN	Distribution		34.50	13.00	0.00	20.00	1	0
98	HAYMOND - IN	Transmission		34.50	13.09	0.00	12.00	1	0
99	HAYMOND - IN	Transmission		34.50	13.09	0.00	20.00	1	0
100	HILLCREST - IN	Transmission		138.00	0.00	0.00	0.00	0	0
101	HILLCREST - IN	Transmission		138.00	13.09	0.00	22.40	1	0
102	HUMMEL CREEK - IN	Transmission		138.00	69.00	34.00	75.00	1	0
103	HUMMEL CREEK - IN	Distribution		138.00	13.09	0.00	20.00	1	0
104	ILLINOIS ROAD - IN	Distribution		138.00	13.09	0.00	20.00	1	0

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105	INDUSTRIAL PARK - IN	Transmission		34.50	13.00	0.00	22.40	1	0
106	INDUSTRIAL PARK - IN	Transmission		138.00	0.00	0.00	0.00	0	0
107	INDUSTRIAL PARK - IN	Transmission		138.00	13.09	0.00	22.40	1	0
108	INDUSTRIAL PARK - IN	Transmission		138.00	69.00	34.00	75.00	1	0
109	IRELAND ROAD - IN	Transmission		138.00	13.09	0.00	20.00	1	0
110	IU PURDUE - IN	Transmission		13.80	4.00	0.00	5.00	1	0
111	JACKSON ROAD - IN	Distribution		138.00	13.09	0.00	32.00	2	0
112	JAY (IM) - IN	Transmission		138.00	0.00	0.00	0.00	0	0
113	JAY (IM) - IN	Distribution		138.00	69.00	34.00	115.00	1	0
114	JEFFERSON (IM) - IN	Generation		765.00	0.00	0.00	0.00	0	0
115	JOBES - IN	Distribution		34.50	4.00	0.00	9.38	1	0
116	JONES CREEK - IN	Transmission		138.00	12.47	0.00	20.00	1	0
117	KANKAKEE - IN	Transmission		138.00	70.50	36.20	130.00	1	0
118	KANKAKEE - IN	Transmission		138.00	13.09	0.00	22.40	1	0
119	KENDALLVILLE - IN	Distribution		138.00	69.00	13.00	75.00	1	0
120	KENDALLVILLE - IN	Distribution		69.00	13.00	0.00	7.50	1	0
121	KENDALLVILLE - IN	Distribution		138.00	0.00	0.00	0.00	0	0
122	KENDALLVILLE - IN	Distribution		69.00	12.00	0.00	10.50	1	0
123	KINGSLAND - IN	Transmission		69.00	13.00	0.00	4.69	1	0
124	KLINE - IN	Transmission		138.00	34.00	0.00	100.00	1	0
125	LANTERN PARK - IN	Transmission		138.00	13.09	0.00	20.00	1	0
126	LIGONIER - IN	Transmission		138.00	13.09	0.00	29.38	2	0
127	LINCOLN - IN	Distribution		138.00	13.09	0.00	20.00	1	0
128	LINCOLN - IN	Distribution		138.00	70.50	36.20	200.00	1	0
129	LINCOLN - IN	Distribution		138.00	36.20	0.00	45.00	1	0
130	LINWOOD (IM) - IN	Distribution		138.00	13.09	0.00	10.50	1	0
131	LYNN - IN	Distribution		69.00	13.00	0.00	7.00	1	0
132	MAGLEY - IN	Distribution		138.00	69.00	13.00	90.00	1	0
133	MAGLEY - IN	Distribution		69.00	13.00	0.00	9.38	1	0
134	MARION ETHANOL - IN	Transmission		34.50	4.00	0.00	10.50	1	0
135	MARION PLANT - IN	Transmission		34.50	13.00	0.00	22.40	1	0
136	MARION PLANT - IN	Transmission		34.50	0.00	0.00	0.00	0	0
137	MARION PLANT - IN	Transmission		34.50	4.00	0.00	6.00	1	0
138	MAYFIELD - IN	Transmission		138.00	13.09	0.00	20.00	1	0
139	MCCLURE - IN	Transmission		34.50	4.00	0.00	7.50	1	0
140	MCGALLIARD ROAD - IN	Transmission		34.50	13.09	0.00	25.00	1	0
141	MCKINLEY - IN	Distribution		138.00	0.00	0.00	0.00	0	0
142	MCKINLEY - IN	Distribution		69.00	0.00	0.00	0.00	0	0
143	MCKINLEY - IN	Distribution		138.00	13.09	0.00	40.00	2	0
144	MCKINLEY - IN	Distribution		138.00	34.00	0.00	112.00	1	0
145	MCKINLEY - IN	Transmission		138.00	70.50	36.20	130.00	1	0
146	MEADOW LAKE SW - IN	Transmission		345.00	0.00	0.00	0.00	0	0
147	MEADOWBROOK - IN	Distribution		138.00	35.00	0.00	100.00	1	0
148	MIER - IN	Distribution		138.00	13.09	0.00	10.50	1	0
149	MILLER AVENUE - IN	Transmission		34.50	4.00	0.00	8.00	1	0
150	MISSISSINEWA - IN	Distribution		138.00	13.09	0.00	0.00	1	0
151	MODOC - IN	Distribution		69.00	13.00	0.00	5.00	1	0
152	MONROE (IM) - IN	Transmission		69.00	13.00	0.00	7.50	1	0
153	MURRAY - IN	Transmission		69.00	13.00	0.00	5.00	1	0
154	NORTH KENDALLVILLE - IN	Transmission		69.00	12.00	0.00	22.40	1	0
155	NORTHLAND - IN	Distribution		138.00	13.09	0.00	32.00	2	0
156	OLIVE - IN	Distribution		345.00	138.00	34.50	675.00	1	0

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157	OLIVE - IN	Distribution		138.00	13.09	0.00	9.38	1	0
158	OSOLO - IN	Distribution		138.00	13.09	0.00	20.00	1	0
159	OSSIAN - IN	Distribution		69.00	13.00	0.00	20.00	1	0
160	PARKWAY - IN	Transmission		34.50	13.00	0.00	4.69	1	0
161	PARNELL - IN	Distribution		34.50	13.09	0.00	12.00	1	0
162	PARNELL - IN	Distribution		34.50	13.00	0.00	20.00	1	0
163	PENDLETON - IN	Distribution		138.00	35.00	0.00	75.00	1	0
164	PENNVILLE - IN	Distribution		138.00	34.00	13.00	7.50	1	0
165	PHILIPS - IN	Distribution		69.00	0.48	0.00	2.50	1	0
166	PINE ROAD - IN	Distribution		138.00	13.09	0.00	20.00	1	0
167	PIPE CREEK - IN	Distribution		138.00	12.00	0.00	20.00	1	0
168	PLEASANT - IN	Distribution		69.00	0.00	0.00	0.00	0	0
169	PLEASANT - IN	Transmission		69.00	13.00	0.00	5.00	1	0
170	PORTLAND (IM) - IN	Transmission		69.00	13.00	0.00	16.80	2	0
171	PRICE - IN	Transmission		69.00	13.09	0.00	20.00	1	0
172	RANDOLPH - IN	Transmission		69.00	0.00	0.00	0.00	0	0
173	RANDOLPH - IN	Distribution		138.00	69.00	13.00	56.00	1	0
174	RANDOLPH - IN	Distribution		138.00	13.09	0.00	22.40	1	0
175	RANDOLPH - IN	Transmission		34.50	12.00	0.00	3.75	1	0
176	REED - IN	Transmission		138.00	13.09	0.00	22.40	1	0
177	ROBISON PARK - IN	Transmission		138.00	13.09	0.00	25.00	1	0
178	ROBISON PARK - IN	Transmission		138.00	13.09	0.00	20.00	1	0
179	ROBISON PARK - IN	Distribution		138.00	70.50	36.20	90.00	1	0
180	ROCKPORT - IN	Distribution		34.50	13.00	0.00	1.50	2	0
181	ROSE HILL - IN	Transmission		138.00	13.00	0.00	7.50	1	0
182	ROYERTON - IN	Transmission		138.00	13.09	0.00	10.50	1	0
183	SATURN - IN	Distribution		138.00	13.09	0.00	12.50	1	0
184	SELMA PARKER - IN	Transmission		138.00	13.09	0.00	20.00	1	0
185	SORENSON - IN	Transmission		138.00	13.09	0.00	9.38	1	0
186	SORENSON - IN	Transmission		345.00	138.00	34.00	675.00	1	0
187	SORENSON - IN	Transmission		765.00	345.00	34.50	750.00	0	1
188	SORENSON - IN	Transmission		345.00	138.00	34.50	675.00	1	0
189	SORENSON - IN	Transmission		765.00	345.00	34.50	750.00	0	1
190	SORENSON - IN	Transmission		765.00	345.00	34.50	750.00	0	1
191	SOUTH BEND - IN	Transmission		138.00	69.00	34.00	130.00	1	0
192	SOUTH BEND - IN	Transmission		138.00	0.00	0.00	0.00	0	0
193	SOUTH BEND - IN	Distribution		138.00	13.09	0.00	20.00	1	0
194	SOUTH BERNE - IN	Distribution		69.00	13.09	0.00	12.00	1	0
195	SOUTH DECATUR - IN	Distribution		69.00	13.00	0.00	20.00	1	0
196	SOUTH DECATUR - IN	Transmission		69.00	13.09	0.00	12.00	1	0
197	SOUTH ELWOOD - IN	Transmission		138.00	13.09	0.00	20.00	1	0
198	SOUTH SIDE (MARION) - IN	Distribution		34.50	13.09	0.00	20.00	1	0
199	SOUTH SIDE (SOUTH BEND) - IN	Distribution		138.00	13.09	0.00	20.00	1	0
200	SOUTH SUMMITVILLE - IN	Transmission		69.00	0.00	0.00	0.00	0	0
201	SOUTH SUMMITVILLE - IN	Distribution		69.00	13.09	0.00	20.00	1	0
202	SOYA - IN	Distribution		34.50	4.36	0.00	7.50	1	0
203	SPRING STREET - IN	Distribution		34.50	13.00	0.00	7.50	1	0
204	SPRING STREET - IN	Distribution		34.50	12.00	0.00	12.00	1	0
205	SPY RUN SF6 - IN	Transmission		138.00	13.09	0.00	22.40	1	0
206	SPY RUN SF6 - IN	Transmission		138.00	34.00	0.00	200.00	2	0
207	ST. JOE - IN	Distribution		69.00	13.09	0.00	20.00	1	0
208	STATE STREET - IN	Distribution		138.00	13.09	0.00	25.00	1	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
209	STUDEBAKER - IN	Distribution		138.00	13.80	0.00	36.00	2	0
210	STUDEBAKER - IN	Distribution		138.00	13.09	0.00	12.00	1	0
211	SUMMIT - IN	Distribution		138.00	13.09	0.00	20.00	1	0
212	SUMMIT - IN	Transmission		138.00	13.09	0.00	12.00	1	0
213	SWANSON - IN	Distribution		69.00	34.00	0.00	45.00	2	0
214	SWANSON - IN	Distribution		69.00	0.00	0.00	0.00	0	0
215	THOMAS ROAD - IN	Distribution		69.00	12.00	0.00	40.00	2	0
216	THOMAS ROAD - IN	Distribution		69.00	12.00	0.00	40.00	2	0
217	THOMAS ROAD - IN	Distribution		69.00	13.09	0.00	40.00	2	0
218	THOMAS ROAD - IN	Distribution		69.00	13.09	0.00	40.00	2	0
219	THREE M - IN	Transmission		69.00	13.09	4.16	12.50	1	0
220	THREE RIVERS (FTW) - IN	Transmission		34.50	13.00	0.00	10.00	2	0
221	TILLMAN - IN	Distribution		138.00	36.20	0.00	18.00	1	0
222	TILLMAN - IN	Distribution		138.00	13.09	0.00	10.00	1	0
223	TORRINGTON - IN	Distribution		34.50	4.00	0.00	9.07	1	0
224	TRIER - IN	Distribution		138.00	13.09	0.00	20.00	1	0
225	TRI-LAKES - IN	Transmission		69.00	13.00	0.00	3.75	1	0
226	TWENTY FIRST STREET - IN	Transmission		34.50	13.00	0.00	18.75	2	0
227	TWENTY THIRD STREET (IM) - IN	Transmission		34.50	0.00	0.00	0.00	0	0
228	TWENTY THIRD STREET (IM) - IN	Transmission		138.00	69.00	34.00	213.00	2	0
229	TWIN BRANCH 138KV - IN	Transmission		138.00	13.09	0.00	20.00	1	0
230	TWIN BRANCH 345KV - IN	Transmission		345.00	138.00	34.50	675.00	1	0
231	UP RIVER DAM - IN	Distribution		34.50	4.00	0.00	1.50	3	0
232	UP RIVER DAM - IN	Distribution		13.80	4.00	0.00	1.50	3	0
233	UPLAND - IN	Distribution		69.00	13.20	0.00	20.00	1	0
234	UTICA (IM) - IN	Distribution		34.50	13.09	0.00	42.40	2	0
235	WABASH AVENUE - IN	Transmission		69.00	13.09	0.00	20.00	1	0
236	WALLEN - IN	Distribution		138.00	13.09	0.00	45.00	2	0
237	WALLEN - IN	Transmission		138.00	69.00	34.00	90.00	1	0
238	WARREN - IN	Transmission		69.00	12.00	0.00	7.00	1	0
239	WATER POLLUTION - IN	Distribution		34.50	4.00	0.00	7.00	1	0
240	WAYNE TRACE - IN	Distribution		138.00	13.09	0.00	22.40	1	0
241	WAYNEDALE - IN	Distribution		138.00	12.47	0.00	20.00	1	0
242	WAYNEDALE - IN	Distribution		138.00	13.09	0.00	22.40	1	0
243	WEST SIDE - IN	Distribution		138.00	13.09	0.00	42.40	2	0
244	WEST SIDE - IN	Distribution		138.00	69.00	34.00	84.00	1	0
245	WINCHESTER (IM) - IN	Distribution		69.00	0.00	0.00	0.00	0	0
246	WINCHESTER (IM) - IN	Transmission		69.00	13.00	0.00	26.25	2	0
247	WOLF LAKE - IN	Transmission		69.00	13.00	0.00	7.50	1	0
248	WOODS ROAD - IN	Transmission		138.00	12.00	0.00	10.00	1	0
249	ALMENA - MI	Transmission		69.00	12.00	0.00	7.00	1	0
250	ALMENA - MI	Transmission		69.00	34.50	0.00	30.00	1	0
251	BANGOR - MI	Distribution		69.00	12.00	0.00	6.25	1	0
252	BARODA - MI	Distribution		138.00	13.09	0.00	20.00	1	0
253	BENTON HARBOR - MI	Transmission		345.00	137.50	13.80	3600.00	8	0
254	BENTON HARBOR WATERWORKS - MI	Transmission		34.50	13.00	0.00	1.00	3	0
255	BRIDGMAN - MI	Distribution		69.00	12.00	0.00	18.90	2	0
256	BRIDGMAN - MI	Distribution		69.00	0.00	0.00	0.00	0	0
257	BUCHANAN HYDRO STA - MI	Transmission		69.00	34.00	0.00	20.00	1	0
258	BUCHANAN HYDRO STA - MI	Transmission		69.00	12.00	0.00	7.50	1	0
259	CAMERON - MI	Distribution		69.00	34.00	0.00	7.50	1	0
260	COLBY - MI	Distribution		138.00	13.09	0.00	8.40	1	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
261	COLBY - MI	Transmission		34.50	0.00	0.00	0.00	0	0
262	COLBY - MI	Transmission		138.00	69.00	34.50	75.00	1	0
263	COLBY - MI	Transmission		69.00	34.50	0.00	20.00	1	0
264	COREY - MI	Distribution		138.00	69.00	34.50	130.00	1	0
265	COREY - MI	Distribution		69.00	0.00	0.00	0.00	0	0
266	COVERT - MI	Transmission		69.00	13.00	0.00	9.38	1	0
267	CRYSTAL - MI	Transmission		138.00	13.09	0.00	22.40	1	0
268	DC COOK 69/12 - MI	Distribution		69.00	0.00	0.00	0.00	0	0
269	EAST WATERVLIET - MI	Distribution		138.00	13.09	0.00	20.00	1	0
270	FLORENCE ROAD - MI	Transmission		69.00	13.09	0.00	12.00	1	0
271	HAGAR - MI	Transmission		69.00	12.00	0.00	10.50	1	0
272	HARTFORD - MI	Transmission		138.00	70.50	36.20	54.00	1	0
273	HARTFORD - MI	Transmission		138.00	70.50	36.20	54.00	1	0
274	HICKORY CREEK - MI	Transmission		138.00	69.00	34.50	75.00	1	0
275	KENZIE CREEK - MI	Transmission		345.00	137.50	13.80	450.00	1	0
276	LAKE STREET - MI	Distribution		69.00	34.00	0.00	40.00	1	0
277	LAKE STREET - MI	Distribution		69.00	0.00	0.00	0.00	0	0
278	LAKESIDE (MBH) - MI	Transmission		69.00	13.09	0.00	9.38	1	0
279	LAKESIDE (MBH) - MI	Transmission		69.00	12.00	0.00	9.38	1	0
280	LANGLEY (IM) - MI	Distribution		34.50	138.00	13.80	14.00	2	0
281	LANGLEY (IM) - MI	Distribution		34.50	34.50	13.80	14.00	2	0
282	MOORE PARK - MI	Distribution		138.00	0.00	0.00	0.00	0	0
283	MOORE PARK - MI	Distribution		138.00	70.50	36.20	54.00	1	0
284	MOORE PARK - MI	Distribution		69.00	0.00	0.00	0.00	0	0
285	MOORE PARK - MI	Transmission		138.00	13.09	0.00	20.00	1	0
286	MURCH - MI	Transmission		69.00	0.00	0.00	0.00	0	0
287	MURCH - MI	Transmission		69.00	12.00	0.00	20.00	1	0
288	NEW BUFFALO - MI	Distribution		69.00	12.00	0.00	30.50	2	0
289	NILES - MI	Transmission		69.00	34.00	0.00	44.80	1	0
290	NILES - MI	Transmission		69.00	0.00	0.00	0.00	0	0
291	NILES - MI	Transmission		69.00	13.09	0.00	20.00	1	0
292	PEARL STREET - MI	Distribution		34.50	12.00	0.00	16.88	2	0
293	PIGEON RIVER - MI	Distribution		69.00	12.00	0.00	20.00	1	0
294	POKAGON(MBH) - MI	Distribution		138.00	69.00	13.00	115.00	1	0
295	POKAGON(MBH) - MI	Transmission		69.00	13.00	0.00	5.00	1	0
296	POKAGON(MBH) - MI	Transmission		69.00	0.00	0.00	0.00	0	0
297	RICKERMAN ROAD - MI	Transmission		138.00	13.09	0.00	7.50	1	0
298	RIVERSIDE (IM) - MI	Transmission		138.00	13.09	0.00	20.00	1	0
299	RIVERSIDE (IM) - MI	Transmission		138.00	69.00	34.00	84.00	1	0
300	RIVERSIDE (IM) - MI	Distribution		138.00	0.00	0.00	0.00	0	0
301	SAUK TRAIL - MI	Distribution		138.00	13.09	0.00	20.00	1	0
302	SCOTTDALE - MI	Distribution		34.50	13.09	0.00	9.38	1	0
303	SISTER LAKES - MI	Transmission		34.50	12.00	0.00	15.04	2	0
304	SODUS - MI	Transmission		138.00	13.09	0.00	10.50	1	0
305	STEVENSVILLE - MI	Transmission		69.00	13.00	0.00	8.40	1	0
306	STEVENSVILLE - MI	Distribution		69.00	13.09	0.00	12.50	1	0
307	STONE LAKE - MI	Distribution		69.00	12.00	0.00	9.38	1	0
308	STONE LAKE - MI	Transmission		69.00	13.00	0.00	7.00	1	0
309	STUBEY ROAD - MI	Transmission		69.00	12.00	0.00	10.50	1	0
310	STUBEY ROAD - MI	Transmission		69.00	0.00	0.00	0.00	0	0
311	THREE OAKS - MI	Distribution		69.00	12.00	0.00	6.25	1	0
312	VALLEY - MI	Transmission		138.00	69.00	34.00	75.00	1	0

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313	VICKSBURG - MI	Transmission		69.00	12.00	0.00	9.38	1	0
314	VICKSBURG - MI	Transmission		69.00	13.09	0.00	20.00	1	0
315	WEST STREET - MI	Distribution		138.00	13.09	0.00	20.00	1	0
316	WHEELER STREET - MI	Distribution		69.00	13.00	0.00	8.40	1	0
317	WOLVERINE - MI	Distribution		69.00	13.00	2.40	5.00	1	0
318	WOLVERINE - MI	Distribution		69.00	13.00	2.40	5.00	1	0
319	TotalTransmissionSubstationMember								
320	Total								

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
1		0	0.00
2		0	0.00
3	STATCAP	1	14.40
4	STATCAP	1	52.79
5		0	0.00
6		0	0.00
7		0	0.00
8		0	0.00
9		0	0.00
10		0	0.00
11		0	0.00
12		0	0.00
13		0	0.00
14		0	0.00
15		0	0.00
16		0	0.00
17	STATCAP	2	105.59
18		0	0.00
19	STATCAP	1	16.20
20		0	0.00
21		0	0.00
22		0	0.00
23		0	0.00
24		0	0.00
25	STATCAP	1	16.20
26	STATCAP	1	16.20
27		0	0.00
28	STATCAP	2	30.00
29		0	0.00
30		0	0.00
31		0	0.00
32		0	0.00
33		0	0.00
34		0	0.00
35		0	0.00
36		0	0.00
37		0	0.00
38		0	0.00
39		0	0.00
40	STATCAP	1	57.60
41		0	0.00
42		0	0.00
43		0	0.00
44		0	0.00
45		0	0.00
46		0	0.00
47		0	0.00
48		0	0.00
49	XSLR - 0.4mH / 480A	3	0.00
50	STATCAP	1	23.00
51	STATCAP	2	29.70
52		0	0.00
53	STATCAP	1	57.60

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
54		0	0.00
55		0	0.00
56		0	0.00
57	STATCAP	2	52.79
58	XSLR - 0.6mH / 480A	3	0.00
59	STATCAP	1	4.80
60		0	0.00
61		0	0.00
62		0	0.00
63		0	0.00
64		0	0.00
65	REACTOR	2	200.00
66		0	0.00
67		0	0.00
68		0	0.00
69		0	0.00
70		0	0.00
71		0	0.00
72		0	0.00
73		0	0.00
74		0	0.00
75		0	0.00
76		0	0.00
77		0	0.00
78	STATCAP	1	9.60
79		0	0.00
80		0	0.00
81	STATCAP	1	13.19
82		0	0.00
83		0	0.00
84		0	0.00
85		0	0.00
86		0	0.00
87		0	0.00
88		0	0.00
89		0	0.00
90		0	0.00
91	REACTOR	4	200.00
92		0	0.00
93		0	0.00
94		0	0.00
95		0	0.00
96		0	0.00
97		0	0.00
98		0	0.00
99		0	0.00
100	STATCAP	1	52.79
101		0	0.00
102		0	0.00
103		0	0.00
104		0	0.00
105		0	0.00
106	STATCAP	1	50.40

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
107		0	0.00
108		0	0.00
109		0	0.00
110		0	0.00
111		0	0.00
112	STATCAP	1	57.60
113		0	0.00
114	REACTOR	3	300.00
115		0	0.00
116		0	0.00
117		0	0.00
118		0	0.00
119		0	0.00
120		0	0.00
121	STATCAP	1	43.20
122		0	0.00
123		0	0.00
124		0	0.00
125		0	0.00
126		0	0.00
127		0	0.00
128		0	0.00
129		0	0.00
130		0	0.00
131		0	0.00
132		0	0.00
133		0	0.00
134		0	0.00
135		0	0.00
136	STATCAP	1	8.75
137		0	0.00
138		0	0.00
139		0	0.00
140		0	0.00
141	STATCAP	1	86.40
142	STATCAP	1	21.60
143		0	0.00
144		0	0.00
145		0	0.00
146	STATCAP	2	0.00
147		0	0.00
148		0	0.00
149		0	0.00
150		0	0.00
151		0	0.00
152		0	0.00
153		0	0.00
154		0	0.00
155		0	0.00
156		0	0.00
157		0	0.00
158		0	0.00
159		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
160		0	0.00
161		0	0.00
162		0	0.00
163		0	0.00
164		0	0.00
165		0	0.00
166		0	0.00
167		0	0.00
168	STATCAP	1	13.19
169		0	0.00
170		0	0.00
171		0	0.00
172	STATCAP	1	13.50
173		0	0.00
174		0	0.00
175		0	0.00
176		0	0.00
177		0	0.00
178		0	0.00
179		0	0.00
180		0	0.00
181		0	0.00
182		0	0.00
183		0	0.00
184		0	0.00
185		0	0.00
186		0	0.00
187		0	0.00
188		0	0.00
189		0	0.00
190		0	0.00
191		0	0.00
192	STATCAP	1	52.79
193		0	0.00
194		0	0.00
195		0	0.00
196		0	0.00
197		0	0.00
198		0	0.00
199		0	0.00
200	STATCAP	1	0.00
201		0	0.00
202		0	0.00
203		0	0.00
204		0	0.00
205		0	0.00
206		0	0.00
207		0	0.00
208		0	0.00
209		0	0.00
210		0	0.00
211		0	0.00
212		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
213		0	0.00
214	STATCAP	1	14.40
215		0	0.00
216		0	0.00
217		0	0.00
218		0	0.00
219		0	0.00
220		0	0.00
221		0	0.00
222		0	0.00
223		0	0.00
224		0	0.00
225		0	0.00
226		0	0.00
227	STATCAP	2	28.80
228		0	0.00
229		0	0.00
230		0	0.00
231		0	0.00
232		0	0.00
233		0	0.00
234		0	0.00
235		0	0.00
236		0	0.00
237		0	0.00
238		0	0.00
239		0	0.00
240		0	0.00
241		0	0.00
242		0	0.00
243		0	0.00
244		0	0.00
245	STATCAP	1	10.80
246		0	0.00
247		0	0.00
248		0	0.00
249		0	0.00
250		0	0.00
251		0	0.00
252		0	0.00
253		0	0.00
254		0	0.00
255		0	0.00
256	STATCAP	1	14.40
257		0	0.00
258		0	0.00
259		0	0.00
260		0	0.00
261	STATCAP	1	12.00
262		0	0.00
263		0	0.00
264		0	0.00
265	STATCAP	1	14.40

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
266		0	0.00
267		0	0.00
268	STATCAP	1	0.00
269		0	0.00
270		0	0.00
271		0	0.00
272		0	0.00
273		0	0.00
274		0	0.00
275		0	0.00
276		0	0.00
277	STATCAP	1	14.40
278		0	0.00
279		0	0.00
280		0	0.00
281		0	0.00
282	STATCAP	1	56.70
283		0	0.00
284	STATCAP	1	16.20
285		0	0.00
286	STATCAP	1	13.20
287		0	0.00
288		0	0.00
289		0	0.00
290	STATCAP	1	14.39
291		0	0.00
292		0	0.00
293		0	0.00
294		0	0.00
295		0	0.00
296	STATCAP	1	14.39
297		0	0.00
298		0	0.00
299		0	0.00
300	STATCAP	1	52.80
301		0	0.00
302		0	0.00
303		0	0.00
304		0	0.00
305		0	0.00
306		0	0.00
307		0	0.00
308		0	0.00
309		0	0.00
310	STATCAP	1	14.40
311		0	0.00
312		0	0.00
313		0	0.00
314		0	0.00
315		0	0.00
316		0	0.00
317		0	0.00
318		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
319			1,891
320			1,891

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Administrative and General Expenses - Maintenance	[(a)] AEPSC	935	5,266,971
3	Administrative and General Expenses - Operation	AEPSC	920-926,928,930-931	5,865,595
4	AEPSC Support Svcs	AEPSC	417	1,456,155
5	Audit Services	AEPSC	920/923	1,200,534
6	Building and Property Leases	IMTCo	567/589	749,896
7	Central Machine Shop	APCo	107, 108,163,500,506,512,513,524,530,531,544,592	2,497,038
8	Civil & Political Activities and Other Svcs	AEPSC	426	615,231
9	Coal Transloading	AEGCo	151	11,398,147
10	Construction Services	AEPSC	107/108/120	76,914,026
11	Corp Safety & Health	AEPSC	920/923	1,061,880
12	Corporate Accounting	AEPSC	920/923	2,236,767
13	Corporate Planning & Budgeting	AEPSC	920/923	1,605,595
14	Customer Accounts Expenses	AEPSC	901-905	9,224,086
15	Distribution Expenses - Maintenance	OPCo	593-598	389,309
16	Distribution Expenses - Operation	AEPSC	580-588	3,427,762
17	Environmental Services	AEPSC	920/923	450,939
18	Expenses of Nonutility Operations	APCo	417	5,016,709
19	Factored Customer A/R Bad Debts	AEP Credit	426	4,559,956
20	Factored Customer A/R Expense	AEP Credit	426	10,942,249
21	Federal Affairs	AEPSC	920/923	777,021
22	Fuel & Storeroom Services	AEPSC	152,163	5,183,567
23	Human Resources	AEPSC	920/923	5,798,205
24	Hydraulic Power Generation - Operation	AEPSC	535-540	962,808
25	Information Technology	AEPSC	920/923	12,801,057
26	Infrastructure Ops & Support	AEPSC	920/923	1,528,319
27	Legal GC/Administration	AEPSC	920/923	4,620,139
28	Materials and Supplies	OHTCo	107/571	433,195
29	Materials and Supplies	OPCo	107, 108,154,184,186,530,560,570,571,592,595,935	3,198,761
30	Nuclear Power Generation - Maintenance	AEPSC	528,530,532	1,272,996
31	Nuclear Power Generation - Operation	AEPSC	517,520,524	334,412
32	Other Power Supply Expenses	AEPSC	556/557	3,369,467
33	Other Property and Investments	AEPSC	121/122	275,108
34	Physical & Cyber Security	AEPSC	920/923	875,776
35	Rail Car Lease	SWEPCo	186	723,432
36	Rail Car Maintenance	AEGCo	151	343,019
37	Research and Other Services	AEPSC	183,186,188	5,892,503
38	Steam Power Generation - Maintenance	AEPSC	510-514	2,203,148
39	Steam Power Generation - Operation	AEPSC	500-502,506,508	6,498,277
40	Strategy & Transformation	AEPSC	920/923	259,622
41	Supply Chain & Fleet and Property Management	AEPSC	920/923	3,118,390
42	Tax Services	AEPSC	920/923	1,030,724
43	Transmission Expenses - Maintenance	AEPSC	568,569,570-571	564,496
44	Transmission Expenses - Operation	AEPSC	560-563,566,920,923	7,626,132
45	Treasury & Risk	AEPSC	920/923	3,286,201
19				

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
20	**Non-power Goods or Services Provided for Affiliated**			
21	Barging	AEGCo	417	9,269,281
22	Barging	APCo	417	39,168,416
23	Barging	WPCo	417	10,593,187
24	Building and Property Leases	AEPSC	454	1,562,115
25	Construction Services	IMTCo	108/107	9,967,430
26	Construction Services	OPCo	108/107	326,422
27	Construction Services	SWEPCo	108/107	565,045
28	Distribution Expenses - Maintenance	OPCo	592-597	310,187
29	Distribution Expenses - Maintenance	SWEPCo	592-594, 596-597	980,984
30	Fleet and Vehicle Charges	AEPSC	188	369,380
31	Fuel Carbon Activation	AEGCo	154, 502	790,477
32	Fuel Consumed - Ammonia	AEGCo	154, 502	313,106
33	Fuel Consumed Handling	AEGCo	152, 501	2,862,484
34	Materials and Supplies	OPCo	154	651,847
35	Rail Car Lease	PSO	151	285,912
36	Rail Car Lease	(b) SWEPCo	151	1,207,683
37	Rockport Joint Books	AEGCo	500/935	61,625,993
38	Sodium Bicarbonate Activation	AEGCo	154, 502	3,236,861
39	Transmission Expenses - Maintenance	IMTCo	568-573	1,661,618
40	Transmission Expenses - Operation	IMTCo	560-563, 566	2,676,268
41	Deferred Credits	AEGCo	253	325,873
42	Use of Jointly Owned Facility	IMTCo	454	7,075,845
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FOOTNOTE DATA

(a) Concept: NameOfAssociatedAffiliatedCompany

Certain managerial and professional services provided by AEPSC are allocated among multiple affiliates. The costs of the services are billed on a direct-charge basis, whenever possible. Costs incurred to perform services that benefit more than one company are allocated to the benefiting companies using one of 80 FERC accepted allocation factors. The allocation factors used to bill for services performed by AEPSC are based upon formulae that consider factors such as number of customers, number of employees, number of transmission miles, number of invoices and other factors. The data upon which these formulae are based is updated monthly, quarterly, semi-annually or annually, depending on the particular factor and its volatility. The billings for service are made at cost and include no compensation for a return on investment.

(b) Concept: NameOfAssociatedAffiliatedCompany

The Rockport Plant is owned 50% by I&M and 50% by AEG. I&M is the operator of the plant and most charges originate on I&M's general ledger. A joint books process then allocates 50% of those charges to AEG.