THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

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)	Year/Period of Report
Indiana Michigan Power Company	End of 2017/Q4

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 and Licensees 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 Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(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.)

Reference 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 _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed 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. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(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 http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.asp#3Q-gas .

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, submit the electronic filing using the form submission software only. 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.

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 be 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 salt 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. 1/3-Q:
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 2017/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 Kyle P. Rura	06 Title of Contact Person Accountant
07 Address of Contact Person *(Street, City, State, Zip Code)* AEP Service Corp., 1 Riverside Plaza, Columbus, OH 43215-2373	

08 Telephone of Contact Person, *Including Area Code* (614) 716-1000	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

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	03 Signature Jeffrey W. Hoersdig	04 Date Signed *(Mo, Da, Yr)* 04/12/2018
02 Title Assistant Controller		

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	Page 116 - NA
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	NA
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	NA
25	Unrecovered Plant and Regulatory Study Costs	230	NA
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	NA
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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".

LIST OF SCHEDULES (Electric Utility) (continued)

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".

Stockholders' Reports Check appropriate box:

- [X] Two copies will be submitted
- [ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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, Assistant Controller
1 Riverside Plaza
Columbus, Ohio 43215

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

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.

None

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

Electric - Indiana
Electric - 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) [X] Yes...Enter the date when such independent accountant was initially engaged: 03/02/2017
(2) [ ] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent 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 beneficiearies for whom trust was maintained, and purpose of the trust.

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

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	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)
1	See Footnote		
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Schedule Page: 104 Line No.: 1 Column: a

Summary Compensation Table

The following table provides summary information concerning compensation earned by our Chief Executive Officer, our Chief Financial Officer and the three other most highly compensated executive officers, to whom we refer collectively as the named executive officers.

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)	Stock Awards ($)(2)	Non-Equity Incentive Plan Compensation ($)(3)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(4)	All Other Compensation ($)(5)	Total ($)
Nicholas K. Akins— Chairman of the Board and Chief Executive Officer	2017	1,375,000	—	7,983,420	1,700,000	361,001	111,040	11,530,461
Brian X. Tierney— Executive Vice President and Chief Financial Officer	2017	750,000	—	2,128,899	555,000	462,223	98,262	3,994,384
David M. Feinberg— Executive Vice President, General Counsel and Secretary	2017	632,000	—	1,277,372	406,000	104,619	73,347	2,493,338
Lisa M. Barton— Executive Vice President-Transmission	2017	550,000	—	1,277,372	356,000	110,304	67,724	2,361,400
Lana L. Hillebrand— Executive Vice President-Chief Administrative Officer	2017	577,000	—	1,011,219	375,000	193,929	69,817	2,226,965

(1) Amounts in the salary column are composed of executive salaries earned for the year shown.

(2) The amounts reported in this column reflect the aggregate grant date fair value calculated in accordance with FASB ASC Topic 718 of the performance units and restricted stock units (RSUs) 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, 2017 for a discussion of the relevant assumptions used in calculating these amounts. The value realized for the performance units, if any, will depend on the Company's performance during a three-year performance period. The potential payout can range from 0 percent to 200 percent of the target number of performance units, plus any dividend equivalents. The value of the performance units granted in 2017 will be based on two equally weighted measures: a Board approved cumulative operating earnings per share measure (Cumulative EPS) and a total shareholder return measure (Relative TSR). The grant date fair value of the 2017 performance units that are based on Cumulative EPS was computed in accordance with FASB ASC Topic 718 based upon the probable outcome of the performance conditions as of the grant date. Assuming the highest level of performance achievement as of the grant date, the aggregate grant date fair value of the Cumulative EPS awards would have been: $5,625,011 for Mr. Akins; $1,499,982 for Mr. Tierney; $900,040 for Mr. Feinberg; $900,040 for Ms. Barton and $712,519 for Ms. Hillebrand. As the performance units that are based on Relative TSR are subject to market conditions as defined under FASB ASC Topic 718, they had no maximum grant date fair values that differed from the grant date fair values presented in the table. The performance units granted in 2017 were changed to settle in AEP shares, rather than cash, as was the case for the performance units granted in 2015 and 2016. Because the 2017 performance units are to be settled in AEP shares and the Relative TSR measure is a market condition, the maximum value is factored into the calculation of the grant date fair value. The grant date fair value of the 2017 performance units is approximately 8.6 percent higher due to the accounting impact of the change in settling the performance units in AEP shares rather than cash. The RSUs vest over a forty month period from their January 1 effective date.

(3) The amounts shown in this column are annual incentive compensation paid. At the outset of each year, the HR Committee sets annual incentive targets and performance criteria that are used after year-end to determine if and the extent to which executive officers may receive annual incentive award payments.

(4) 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 plans determined using interest rate and mortality assumptions consistent with those used in the Company's financial statements. See Note 8 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2017 for a discussion of the relevant assumptions. None of the named executive officers received preferential or above-market earnings on deferred compensation.

(5) Amounts shown in the All Other Compensation column for 2017 include: (a) Company contributions to the Company's Retirement Savings Plan, (b) Company contributions to the Company's Supplemental Retirement Savings Plan and (c) perquisites. The amounts are listed in the following table:

Type	Nicholas K. Akins	Brian X. Tierney	David M. Feinberg	Lisa M. Barton	Lana L. Hillebrand
Retirement Savings Plan Match	$ 11,804	$ 12,150	$ 12,150	$ 12,150	$ 12,150
Supplemental Retirement Savings Plan Match	$ 77,850	$ 66,112	$ 49,107	$ 41,815	$ 43,936
Perquisites	$ 21,386	$ 20,000	$ 12,090	$ 13,759	$ 13,731
Total	**$ 111,040**	**$ 98,262**	**$ 73,347**	**$ 67,724**	**$ 69,817**

Perquisites provided in 2017 included: financial counseling and tax preparation services, and, for Mr. Akins, director's accidental death 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 sporting events (subject to our policies on conflicts of interest).

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Nicholas K. Akins - Chief Executive Officer ***	Columbus, Ohio
2	- Chairman of the Board **	
3		
4	Mark C. McCullough - Vice President ***	Columbus, Ohio
5		
6	Marc E. Lewis- VP - External & Regulatory Affairs	Fort Wayne, Indiana
7		
8	Robert P. Powers ***	Columbus, Ohio
9		
10	Brian X. Tierney - Vice President ***	Columbus, Ohio
11	- Chief Financial Officer	
12		
13	Lisa M. Barton - Vice President ***	Columbus, Ohio
14		
15	Thomas A. Kratt - VP Distribution Region Operations	Fort Wayne, Indiana
16		
17	Carla E. Simpson	Fort Wayne, Indiana
18		
19	David A. Lucas - Vice President Finance	Fort Wayne, Indiana
20		
21	Toby L. Thomas - President	Fort Wayne, Indiana
22	- Chief Operating Officer	
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24	Nicholas M. Elkins	Fort Wayne, Indiana
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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

Does the respondent have formula rates?

[X] 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	FERC Proceeding
1	Rate Schedule 102	ER06-1079 : ER08-219
2	Rate Schedule 103	ER06-1117 : ER08-262
3	Rate Schedule 104	ER06-1076 : ER08-217
4	Rate Schedule 105	ER06-1068 : ER08-216
5	Rate Schedule 106	ER06-1078 : ER08-240
6	Rate Schedule 107	ER06-1080 : ER08-239
7	Rate Schedule 108	ER06-1077 : ER08-310
8	Rate Schedule 109	ER06-1082 : ER08-215
9	Rate Schedule 110	ER06-1081 : ER08-304
10	Rate Schedule 111	ER06-1153 : ER08-310
11	Rate Schedule 112	ER06-1258
12		
13	PJM Interconnection LLC - Attachment H-14	ER08-1329 : ER17-405
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Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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)?	[X] Yes [ ] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20170314-5197	03/14/2017	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14
2	20170526-5103	05/25/2017	ER08-1329 : ER17-405	AEP PJM OATT Annual Formula Rate	PJM OATT Attachment H-14
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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).	Schedule	Column	Line No
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
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 Page 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.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1.

Date Acquired Or Extended	Community	Period of Franchise & Termination	Consideration
Accepted on June 9, 2017, effective June 29, 2017	Township of Volinia, Cass County, Michigan	Ten (10) year franchise renewal expiring on June 28, 2027	None
Accepted August 25, 2017 effective May 25, 2017	Marcellus Township, Cass County, Michigan	Thirty (30) year franchise renewal expiring on May 25, 2047	None
Accepted on June 9, 2017, effective June 29, 2017	Township of Wayne, Cass County, Michigan	Ten (10) year franchise renewal expiring on June 28, 2027	None
Accepted on August 25, 2017, effective July 10, 2017	Pokagon Township, St. Joseph County, Michigan	Thirty (30) year franchise renewal expiring on July 10, 2047	None
Accepted August 25, 2017, effective July 11, 2017	Village of Marcellus, Cass County, Michigan	Thirty (30) year franchise renewal expiring on July 11, 2047	None
Renewed October 10, 2017, Accepted October 23, 2017	Keeler Township, Van Buren County, Michigan	Thirty (30) year franchise renewal expiring on October 22, 2047	None
Renewed on November 10, 2017	LaGrange Township, Cass County, Michigan	Ten (10) year franchise renewal expiring on November 9, 2027	None

2. None

3. None

4. None

5. None

6. $300,000,000 Senior Unsecured Notes (Indiana Commission Authority, Cause No. 44679)

   $69,500,000 nuclear fuel capital lease (Indiana Commission Authority, Cause No. 44827)

   $50,000,000 Pollution Control Bond (Indiana Commission Authority, Cause No. 44904)

   $35,000 Letter of Credit issued by American Electric Power Company, Inc. on behalf of Indiana Michigan Power Company to benefit Travelers Insurance (FERC Authority, Docket No. ES-15-52-000)

7. None

8. Cook Nuclear Plant Maintenance employees represented by IBEW #1392 were provided with a 3% general wage increase effective April 1, 2017

   Cook Nuclear Plant Stores employees represented by IBEW #1392 were provided with a 3% general wage increase effective April 1, 2017

   Cook Nuclear Plant RPEC employees represented by IBEW #1392 were provided with a 3% general wage increase effective April 1, 2017

   Michiana Region employees represented by IBEW #1392 were provided with a 2.5% general wage increase effective November 1, 2017

   Fort Wayne District employees represented by IBEW #1392 were provided with a 2.5% general wage increase effective November 1, 2017

   Muncie District employees represented by IBEW #1392 were provided with a 2.5% general wage increase effective November 1, 2017

   TFS T-Line employees represented by IBEW #1392 were provided with a 2.5% general wage increase effective November 1, 2017

   Southern Maintenance Group employees represented by IBEW #1392 were provided with a 2.5% general wage increase effective November 1, 2017

   Three River Area employees represented by IBEW #876 were provided with a 2.5% general wage increase effective November 1, 2017

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

10. None

11. (Reserved)

12. Not Used

13. Toby L. Thomas elected as Director effective 1/1/2017
    Toby L. Thomas elected as President and Chief Operating Officer effective 1/1/2017
    Jeffery D. LaFleur elected as Vice President effective 1/1/2017
    F. Scott Travis resigned as Assistant Controller effective 7/1/2017
    Jeffrey W. Hoersdig elected as Assistant Controller effective 7/20/2017
    Robert P. Powers resigned as Director effective 8/4/2017
    James X. Llende elected as Vice President - Tax effective 11/17/2017
    Jeffery D. LaFleur resigned as Vice President effective 12/2/2017

14. Proprietary capital ratio exceeds 30%

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)	200-201	8,332,896,583	7,675,210,553
3	Construction Work in Progress (107)	200-201	460,208,619	654,208,671
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		8,793,105,202	8,329,419,224
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,948,719,776	2,953,225,228
6	Net Utility Plant (Enter Total of line 4 less 5)		5,844,385,426	5,376,193,996
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	37,447,359	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		1,347,289	1,493,621
10	Spent Nuclear Fuel (120.4)		695,441,601	684,727,053
11	Nuclear Fuel Under Capital Leases (120.6)		180,028,830	239,146,482
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	695,661,521	685,160,271
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		218,603,558	240,206,885
14	Net Utility Plant (Enter Total of lines 6 and 13)		6,062,988,984	5,616,400,881
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		28,139,049	28,155,997
19	(Less) Accum. Prov. for Depr. and Amort. (122)		12,180,000	14,949,362
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	19,061,859	18,676,961
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	27,124,423	28,479,047
24	Other Investments (124)		13,524,077	13,600,139
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		2,527,614,722	2,256,242,999
29	Special Funds (Non Major Only) (129)		71,055,571	19,045,518
30	Long-Term Portion of Derivative Assets (175)		720,561	-515
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		2,675,060,262	2,349,250,784
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		1,326,155	1,216,639
36	Special Deposits (132-134)		11,624,090	11,916,585
37	Working Fund (135)		3,800	4,200
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		56,348,872	60,062,477
41	Other Accounts Receivable (143)		1,947,471	715,426
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		206,193	8,335
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		47,313,331	48,270,212
45	Fuel Stock (151)	227	30,732,935	31,333,494
46	Fuel Stock Expenses Undistributed (152)	227	621,540	922,321
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	156,944,999	147,193,957
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	2,112,441	2,093,490
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	28,650,949	30,011,063

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

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)
53	(Less) Noncurrent Portion of Allowances		27,124,423	28,479,047
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		8,241,341	8,140,253
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		171,856	84,190
60	Rents Receivable (172)		87,047	85,370
61	Accrued Utility Revenues (173)		7,288,586	1,464,322
62	Miscellaneous Current and Accrued Assets (174)		16,882,969	27,104,369
63	Derivative Instrument Assets (175)		8,289,835	3,489,282
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		720,561	-515
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		350,537,040	345,620,783
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		12,912,315	10,012,590
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	604,411,370	703,726,641
73	Prelim. Survey and Investigation Charges (Electric) (183)		19,607,892	14,659,542
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	49,654,743	45,167,922
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		8,418,221	9,464,111
82	Accumulated Deferred Income Taxes (190)	234	1,096,784,602	914,977,833
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,791,789,143	1,698,008,639
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		10,880,375,429	10,009,281,087

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	/ /	end of 2017/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)	250-251	56,583,866	56,583,866
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		4,234,635	4,234,635
7	Other Paid-In Capital (208-211)	253	976,661,804	976,661,804
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	1,198,555,445	1,137,197,580
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-6,289,416	-6,674,314
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-12,123,365	-16,256,513
16	Total Proprietary Capital (lines 2 through 15)		2,217,622,969	2,151,747,058
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
19	(Less) Reaquired Bonds (222)	256-257	0	40,000,000
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	2,574,997,049	2,274,166,356
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		5,626,318	4,092,431
24	Total Long-Term Debt (lines 18 through 23)		2,569,370,731	2,230,073,925
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		120,623,624	151,577,694
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		47,070	135,954
29	Accumulated Provision for Pensions and Benefits (228.3)		13,890,872	41,388,308
30	Accumulated Miscellaneous Operating Provisions (228.4)		952,363	618,570
31	Accumulated Provision for Rate Refunds (229)		8,298,302	1,733,079
32	Long-Term Portion of Derivative Instrument Liabilities		120,346	784,272
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		1,321,774,265	1,258,078,633
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,465,706,842	1,454,316,510
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		154,463,275	179,023,029
39	Notes Payable to Associated Companies (233)		211,574,416	215,200,760
40	Accounts Payable to Associated Companies (234)		98,281,769	75,589,800
41	Customer Deposits (235)		37,670,440	34,318,118
42	Taxes Accrued (236)	262-263	21,741,646	40,500,980
43	Interest Accrued (237)		38,833,706	33,950,734
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

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)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		6,128,996	5,974,040
48	Miscellaneous Current and Accrued Liabilities (242)		97,907,431	126,803,593
49	Obligations Under Capital Leases-Current (243)		99,312,463	127,082,774
50	Derivative Instrument Liabilities (244)		3,602,082	1,070,724
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		120,346	784,272
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		769,395,878	838,730,280
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	34,075,627	38,781,415
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	34,850,849	41,454,521
60	Other Regulatory Liabilities (254)	278	1,738,909,747	813,464,188
61	Unamortized Gain on Reaquired Debt (257)		9,843	11,555
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	17,658,664	13,008,872
63	Accum. Deferred Income Taxes-Other Property (282)		886,503,347	1,306,253,605
64	Accum. Deferred Income Taxes-Other (283)		1,146,270,932	1,121,439,158
65	Total Deferred Credits (lines 56 through 64)		3,858,279,009	3,334,413,314
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		10,880,375,429	10,009,281,087

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin 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.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

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)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	2,051,641,009	2,132,155,074		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,184,121,791	1,229,884,087		
5	Maintenance Expenses (402)	320-323	208,395,755	205,639,991		
6	Depreciation Expense (403)	336-337	179,225,778	165,679,453		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	1,723,493	1,483,959		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	29,698,986	24,246,045		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		295,199	304,310		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	88,676,779	90,888,833		
15	Income Taxes - Federal (409.1)	262-263	-107,960,156	-40,945,728		
16	- Other (409.1)	262-263	-8,681,078	3,464,156		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	616,889,770	538,797,120		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	419,971,665	432,951,579		
19	Investment Tax Credit Adj. - Net (411.4)	266	-4,705,788	3,772,674		
20	(Less) Gains from Disp. of Utility Plant (411.6)		285,054	251,809		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		406	577,807		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		8,248,773	9,881,955		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,775,672,177	1,799,315,660		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		275,968,832	332,839,414		

STATEMENT OF INCOME FOR THE YEAR (Continued)

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 purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders 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.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
2,051,641,009	2,132,155,074					2
						3
1,184,121,791	1,229,884,087					4
208,395,755	205,639,991					5
179,225,778	165,679,453					6
1,723,493	1,483,959					7
29,698,986	24,246,045					8
						9
						10
						11
295,199	304,310					12
						13
88,676,779	90,888,833					14
-107,960,156	-40,945,728					15
-8,681,078	3,464,156					16
616,889,770	538,797,120					17
419,971,665	432,951,579					18
-4,705,788	3,772,674					19
285,054	251,809					20
						21
406	577,807					22
						23
8,248,773	9,881,955					24
1,775,672,177	1,799,315,660					25
275,968,832	332,839,414					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		275,968,832	332,839,414		
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)		73,524,249	76,220,301		
34	(Less) Expenses of Nonutility Operations (417.1)		67,655,029	68,528,355		
35	Nonoperating Rental Income (418)		50,471	-60,008		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	384,898	-6,705,730		
37	Interest and Dividend Income (419)		1,655,200	1,049,300		
38	Allowance for Other Funds Used During Construction (419.1)		11,055,694	15,339,627		
39	Miscellaneous Nonoperating Income (421)		13,050,812	10,724,954		
40	Gain on Disposition of Property (421.1)			54,791		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		32,066,295	28,094,880		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		146,558	167,852		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		548,496	10,359,384		
46	Life Insurance (426.2)					
47	Penalties (426.3)		-4,677	382,071		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,009,052	1,195,948		
49	Other Deductions (426.5)		3,027,326	7,783,231		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		4,726,755	19,888,486		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	3,493,553	3,923,513		
53	Income Taxes-Federal (409.2)	262-263	1,446,300	-3,832,888		
54	Income Taxes-Other (409.2)	262-263	488,790	-39,912		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	20,093,163	19,511,776		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	15,987,137	16,679,207		
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)		9,534,669	2,883,282		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		17,804,871	5,323,112		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		100,206,743	90,712,806		
63	Amort. of Debt Disc. and Expense (428)		2,129,649	1,820,729		
64	Amortization of Loss on Reaquired Debt (428.1)		1,252,844	1,283,093		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		1,712	1,712		
67	Interest on Debt to Assoc. Companies (430)		2,624,419	851,540		
68	Other Interest Expense (431)		7,524,454	10,791,475		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		6,705,457	7,151,193		
70	Net Interest Charges (Total of lines 62 thru 69)		107,030,940	98,306,738		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		186,742,763	239,855,788		
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)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		186,742,763	239,855,788		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, 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 of 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 in 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, include them on pages 122-123.

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		1,133,421,900	1,012,081,054
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		186,357,865	246,561,518
17	Appropriations of Retained Earnings (Acct. 436)			
18	Reclassification of Appropriate Retained Earnings-Amort Reserve Federal		-388,542	(220,672)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-388,542	(220,672)
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	Dividends Declared - Common Stock		-125,000,000	(125,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-125,000,000	(125,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,194,391,223	1,133,421,900
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, 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 of 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 in 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, include them on pages 122-123.

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)
41				
42				
43				
44				
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)		4,164,222	3,775,680
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		4,164,222	3,775,680
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,198,555,445	1,137,197,580
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-6,674,314	31,416
50	Equity in Earnings for Year (Credit) (Account 418.1)		384,898	(6,705,730)
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		-6,289,416	(6,674,314)

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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 Instruction 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)	186,742,763	239,855,788
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	210,648,257	191,409,457
5	Amortization of Regulatory Debits and Credits	295,199	304,310
6	Amortization of Nuclear Fuel	132,854,010	131,186,765
7	Accretion of Asset Retirement Obligations	8,248,773	9,881,955
8	Deferred Income Taxes (Net)	201,024,131	108,678,110
9	Investment Tax Credit Adjustment (Net)	-4,705,788	3,772,674
10	Net (Increase) Decrease in Receivables	4,598,145	2,025,429
11	Net (Increase) Decrease in Inventory	-8,868,653	18,906,006
12	Net (Increase) Decrease in Allowances Inventory	1,360,114	1,961,442
13	Net Increase (Decrease) in Payables and Accrued Expenses	3,650,671	19,008,687
14	Net (Increase) Decrease in Other Regulatory Assets	-25,158,551	-68,368,993
15	Net Increase (Decrease) in Other Regulatory Liabilities	-11,123,531	-8,701,999
16	(Less) Allowance for Other Funds Used During Construction	11,055,694	15,339,627
17	(Less) Undistributed Earnings from Subsidiary Companies	384,898	-6,705,730
18	Other (provide details in footnote):	-86,376,793	-142,298,015
19	Mark-to-Market of Risk Management Contracts	-2,269,195	2,039,007
20	Pension Contributions to Qualified Plant Trust	-12,975,000	-12,741,000
21	Disposition of Tanners Creek Plant Site		-93,458,698
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	586,503,960	394,827,028
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-657,452,440	-608,769,955
27	Gross Additions to Nuclear Fuel	-109,502,938	-131,929,038
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-386,031	-118,934
30	(Less) Allowance for Other Funds Used During Construction	-11,055,694	-15,339,627
31	Other (provide details in footnote):		
32			
33	Acquired Assets	-1,306,503	-240,332
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-757,592,218	-725,718,632
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	5,172,564	5,172,283
38			
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	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-2,300,540,331	-2,999,972,429
45	Proceeds from Sales of Investment Securities (a)	2,256,276,264	2,957,724,059

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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 Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		-25,488
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):	5,958,730	3,464,704
54	(Increase)/Decrease in Other Special Deposits	-56,704	9,563
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-790,781,695	-759,345,940
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	467,000,000	400,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Long Term Debt Issuance Costs	-6,396,577	-5,208,743
66	Net Increase in Short-Term Debt (c)		
67	Proceeds on Nuclear Fuel Sale/Leaseback		174,600,000
68	Proceeds on Capital Leaseback	896,322	683,177
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	461,499,745	570,074,434
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-128,486,550	-1,383,606
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Notes Payable to Associated Companies	-3,626,344	-79,069,645
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-125,000,000	-125,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	204,386,851	364,621,183
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	109,116	102,271
87			
88	Cash and Cash Equivalents at Beginning of Period	1,220,839	1,118,568
89			
90	Cash and Cash Equivalents at End of period	1,329,955	1,220,839

Schedule Page: 120 Line No.: 18 Column: b

	2017	2016
Utility Plant, Net (Includes Purchases of Nuclear Fuel)	$(117,619,185)	$(190,541,004)
Property and Investments, Net	(3,195,239)	2,218,907
Margin Deposits	349,199	(1,579,463)
Prepayments	4,663,274	74,990
Accrued Utility Revenues, Net	(5,824,264)	(1,411,060)
Misc Current and Accrued Assets	11,673,129	7,713,687
Unamortized Debt Expense	1,407,442	988,900
Other Deferred Debits, Net	(8,000,871)	1,597,873
Other Comprehensive Income, Net	1,318,349	1,318,349
Unamortized Discount/Premium on LTD	554,114	505,891
Accumulated Provisions - Misc	6,561,401	(256,608)
Current and Accrued Liabilities, Net	(20,397,221)	(2,118,012)
Other Deferred Credits, Net	42,133,079	39,189,535
Total	$(86,376,793)	$(142,298,015)

Schedule Page: 120 Line No.: 37 Column: b

	2017	2016
Transfer of Assets to Transco	$4,167,583	$3,780,121
Transformer Sales - Affiliated Companies	610,550	638,604
Meter Sales - Affiliated Companies	213,963	598,125
Sale Boiler Feed Pump Rotor Assembly - Affiliated Co.	0	152,061
Sale/Leaseback of Operating Lease	0	3,372
Sale of 2017 Outage Scrap Metal	180,468	0
Total	$5,172,564	$5,172,283

Schedule Page: 120 Line No.: 53 Column: b

	2017	2016
DOE Settlement	$1,900,856	$1,711,872
CIAC Proceeds	4,057,874	1,752,832
Total	$5,958,730	$3,464,704

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 Cormmission 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.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

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 subsidiaries and affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, hedging activities, asset management and commercial and industrial sales in the deregulated Ohio and Texas market.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a competitive AEP subsidiary.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ASU	Accounting Standards Update.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,278 MW nuclear plant owned by I&M.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel VI LLC, DCC Fuel VII, DCC Fuel VIII, DCC Fuel IX, DCC Fuel X and DCC Fuel XI entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.

GLOSSARY OF TERMS FOR NOTES (Continued)

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

Term	Meaning
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.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo, which defined the sharing of costs and benefits associated with their respective generation plants. This agreement was terminated January 1, 2014.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
kV	Kilovolt.
KWh	Kilowatthour.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NO_X	Nitrogen oxide.
NSR	New Source Review.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.

GLOSSARY OF TERMS FOR NOTES (Continued)

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

Terms	Meaning
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.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SIA	System Integration Agreement, effective June 15, 2000, as amended, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SEC	U.S. Securities and Exchange Commission.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
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.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.

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 594,000 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. I&M shares off-system sales margins with its customers.

Effective January 2014, the FERC approved a PCA among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Effective May 2015, the PCA was revised and approved by the FERC to include WPCo. Under the PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. Further, the Restated and Amended 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.

Also effective January 2014, the FERC approved a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies would fulfill their existing obligations under the PJM Reliability Assurance Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR committed to meet capacity obligations of member companies through the PJM Planning year that ended May 31, 2015.

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 and WPCo. Effective January 2014, and revised in May 2015, power and natural gas risk management activities are allocated based on the member companies' respective equity positions. Risk management activities primarily include power and natural gas physical transactions, financially-settled swaps and exchange-traded futures. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts. I&M shared in the revenues and expenses associated with these risk management activities with the member companies.

AEGCo holds a 50% interest in each of the Rockport Plant units and is entitled to 50% of the capacity and associated energy from each unit. Under unit power agreements approved by the FERC, I&M and KPCo purchase approximately 920 MWs and 390 MWs, respectively, of the output from AEGCo's 50% share of the Rockport Plant.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of APCo, I&M, KPCo and WPCo and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the common shareholder's equity of these companies.

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.

I&M is jointly and severally liable for activity conducted by AEPSC on behalf of APCo, I&M, KPCo and WPCo related to power purchase and sale activity.

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 the 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. For non-power goods and services, the FERC requires a nonregulated affiliate to bill an affiliated public utility company at no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. 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 regulates 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 and in Michigan for I&M.

In addition, the FERC regulates the SIA, Operating Agreement, Transmission Agreement and Transmission Coordination Agreement, all of which allocate shared system costs and revenues among the utility subsidiaries that are parties to each agreement. The FERC also regulates the PCA and the Bridge Agreement, see Note 15 - 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 classification of interest on deferred fuel as Interest and Dividends Receivable rather than deferred fuel.
- 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 capital 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 an accrued provision for potential refund as other noncurrent liability rather than a current 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 capital 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 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 capital 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 accumulated deferred investment tax credits in deferred credits rather than in regulatory liabilities and deferred investment tax credits.
- 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 change in emission allowances held for speculation as investing activities instead of operating activities.
- The classification of rents receivable as rents receivable instead of customer accounts receivable.

Accounting for the Effects of Cost-Based Regulation

I&M 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.

Accounting for the Impacts of Tax Reform

Given the significance of the legislative changes resulting from Tax Reform, the timing of its enactment and the widespread applicability to registrants, the SEC staff recognized the potential challenges faced by registrants when reflecting the effects of Tax Reform in their 2017 financial statements. Accordingly, the SEC staff issued Staff Accounting Bulletin 118 (SAB 118) in December 2017, which provides for a one year measurement period to complete the accounting for Tax Reform.

I&M has made reasonable estimates for the measurement and accounting for the impacts of Tax Reform and these estimates are reflected in the December 31, 2017 financial statements as provisional amounts. While I&M was able to make reasonable estimates of the impact of Tax Reform, the final impact may differ from the recorded provisional amounts to the extent refinements are made to the estimated cumulative temporary differences or as a result of additional guidance or technical corrections that may be issued by the IRS or regulatory state commissions that impacts management's interpretation and assumptions utilized. See "Federal Tax Reform" section of Note 12 for additional information.

Cash and Cash Equivalents

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

Supplementary Information

		2017		2016
For the Years Ended December 31,		**(in millions)**		
Cash was Paid (Received) for:				
Interest (Net of Capitalized Amounts)	$	91.1	$	80.7
Income Taxes (Net of Refunds)		(89.9)		(38.9)
Noncash Acquisitions Under Capital Leases		76.6		192.8
As of December 31,				
Construction Expenditures Included in Current and Accrued Liabilities		88.5		106.2
Acquisition of Nuclear Fuel Included in Current and Accrued Liabilities		—		2.1
Expected Reimbursement for Capital Cost of SNF Dry Cask Storage		2.6		0.7

Special Deposits

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

Inventory

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

Accounts Receivable

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 from electric power sales when power is delivered to customers. 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 the interest in the billed and unbilled receivables they acquire from affiliated utility subsidiaries. See “Securitized Accounts Receivable – AEP Credit” section of Note 14 for additional information.

Allowance for Uncollectible Accounts

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. 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 for all amounts outstanding 180 days or greater at 100%, unless specifically identified. Miscellaneous accounts receivable items open less than 180 days may be reserved using specific identification for bad debt reserves.

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 year ended December 31, 2017.

I&M monitors credit levels and the financial condition of its customers on a continuing 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.

Emission Allowances

I&M records emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. The purchases and sales of allowances are reported in the Operating Activities section of the statements of cash flows. Allowances are consumed in the production of energy and are recorded in Operation Expenses at average cost on the statements of income.

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.

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 removed from plant-in-service or CWIP and charged to expense.

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.

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. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

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 contracts 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. The trustee uses multiple pricing vendors for the assets held in the trusts.

Assets in the benefits and nuclear trust and Special Deposits 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 domestic 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, 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 fuel and related emission allowances and emission control chemicals/consumables is charged to expense 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 on 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 amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit 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.

Changes in fuel costs, including purchased power in Indiana and Michigan for I&M are reflected in rates in a timely manner generally through the FAC. The FAC generally includes some sharing of off-system sales margins. A portion of margins from off-system sales are given to customers through the FAC and other rate mechanisms in Indiana and Michigan.

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) 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.

When regulatory assets are probable of recovery through regulated rates, assets are recorded on the balance sheets. Regulatory assets are tested 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 written off as a charge against income.

Electricity Supply and Delivery Activities

I&M recognizes revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. I&M recognizes the revenues on the statement of income upon delivery of the energy to the customer and include unbilled as well as billed amounts. Wholesale transmission revenue is based on FERC approved formula rate filings made for each calendar year using estimated costs. The annual rate filing is compared to actual costs with an over- or under-recovery being trued-up with interest and refunded or recovered in a future year's rates. In accordance with the accounting guidance for "Regulated Operations - Revenue Recognition", I&M recognizes revenue and expense related to the rate true-ups immediately following the annual FERC filings. 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.

Most of the power produced at the generation plants is sold to PJM or SPP. I&M also purchases power from PJM to supply power to customers. These power sales and purchases are reported on a gross basis as revenues and 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 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 and expenses from marketing and risk management transactions that are not derivatives 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. I&M includes realized gains and losses on marketing and risk management transactions in revenues 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). I&M initially records the effective portion of the cash flow hedge's gain or loss 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. I&M defers the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Accounting for Cash Flow Hedging Strategies" section of Note 10.

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 the period 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. I&M revalued deferred tax assets and liabilities at the new federal corporate income tax rate of 21% in December 2017. See Note 12 for additional information related to Tax Reform.

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.

Investment tax credits (ITC) were historically accounted for under the flow-through method, except where regulatory commissions reflected ITC in the rate-making process. In 2016, AEP and subsidiaries changed accounting for the recognition of ITC and elected to apply the preferred deferral methodology.

Deferred ITC is amortized to income tax expense over the life of the asset. Amortization of deferred ITC begins when the asset is placed into service, except where regulatory commissions reflected ITC in the rate-making process, then amortization begins when the cash tax benefit is recognized.

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.

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 an unfunded nonqualified pension plan. 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 8 -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 spent nuclear fuel 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	25%
Fixed Income	59%
Other Investments	15%
Cash and Cash Equivalents	1%

OPEB Plans Assets	Target
Equity	49%
Fixed Income	49%
Cash and Cash Equivalents	2%

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). 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 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 investment in excess of 5% of an outstanding class of any company.
- 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 and some investments in Real Estate Investment Trusts, which are publicly traded real estate securities.

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 and commingled funds 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 investment instruments.

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.

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 spent nuclear fuel trust funds represent funds that regulatory commissions allow I&M to collect through rates to fund future decommissioning and spent nuclear fuel 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 external investment managers who 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 securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments for investments in both debt and equity 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 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 11 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 nonowner 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, 2017 through February 22, 2018, the date that AEP's Form 10-K was issued, and has updated such evaluation for disclosure purposes through April 12, 2018. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

2. NEW ACCOUNTING PRONOUNCEMENTS

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

ASU 2014-09 "Revenue from Contracts with Customers" (ASU 2014-09)

In May 2014, the FASB issued ASU 2014-09 changing the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, determine the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts.

The FASB deferred implementation of ASU 2014-09 under the terms in ASU 2015-14, "Revenue from Contracts with Customers (Topic: 606): Deferral of the Effective Date." The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017, with early adoption permitted.

Management analyzed the impact of the new revenue standard and related ASUs. During 2016 and 2017, revenue contract assessments were completed. Material revenue streams were identified within the AEP System and representative contract/transaction types were sampled. Performance obligations identified within each material revenue stream were evaluated to determine whether the obligations were satisfied at a point in time or over time. Contracts determined to be satisfied over time generally qualified for the invoicing practical expedient since the invoiced amounts reasonably represented the value to customers of performance obligations fulfilled to date. Additionally, the new standard did not give rise to any changes in current accounting systems. Management continues to develop disclosures to comply with the requirements of ASU 2014-09, including disclosures of significant disaggregated revenue streams, and information about fixed performance obligations that are unsatisfied (or partially unsatisfied) as of the end of a reporting period.

Management adopted ASU 2014-09 effective January 1, 2018. The adoption of ASU 2014-09 did not have a material impact on results of operations, financial position or cash flows. Management will continue to actively participate in informal industry forums throughout the period of initial adoption.

ASU 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities" (ASU 2016-01)

In January 2016, the FASB issued ASU 2016-01 revising the reporting model for financial instruments. Under the new standard, equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) are required to be measured at fair value with changes in fair value recognized in net income. For equity investments that do not have a readily determinable fair value, entities are permitted to elect a practicality exception and measure the investment at cost, less impairment, plus or minus observable price changes. The new standard also amends disclosure requirements and requires separate presentation of financial assets and liabilities by measurement category and form of financial asset (that is, securities or loans and receivables) on the balance sheet or the accompanying notes to the financial statements. The amendments also clarify that an entity should evaluate the need for a valuation allowance on a deferred tax asset related to available-for-sale securities in combination with the entity's other deferred tax assets.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017, with early adoption permitted for certain provisions. Management adopted ASU 2016-01 effective January 1, 2018, by means of a cumulative-effect adjustment to the balance sheet. The adoption of ASU 2016-01 did not have an impact on results of operations, financial position or cash flows.

ASU 2016-02 "Accounting for Leases" (ASU 2016-02)

In February 2016, the FASB issued ASU 2016-02 increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheet. Additionally, a capital lease will be known as a finance lease going forward. Leases with lease terms of 12 months or longer will be subject to the new requirements. Fundamentally, the criteria used to determine lease classification will remain the same, but will be more subjective under the new standard.

The new accounting guidance is effective for annual periods beginning after December 15, 2018, with early adoption permitted. The guidance will be applied by means of a modified retrospective approach. The modified retrospective approach will require lessees and lessors to recognize and measure leases at the beginning of the earliest period presented; however, the FASB is currently evaluating whether to provide reporting entities with an additional expedient to adopt the new lease requirements through a cumulative-effect adjustment in the period of adoption. Accordingly, management continues to monitor these standard-setting activities that may impact the transition requirements of the lease standard.

Management continues to analyze the impact of the new lease standard. During 2016 and 2017, lease contract assessments were completed. The AEP System lease population was identified and representative lease contracts were sampled. Based upon the completed assessments, management prepared a system gap analysis to outline new disclosure compliance requirements compared to current system capabilities. Multiple lease system options were also evaluated. Management plans to elect certain of the following practical expedients upon adoption:

Practical Expedient	Description
Overall Expedients (for leases commenced prior to adoption date and must be adopted as a package)	Do not need to reassess whether any expired or existing contracts are/or contain leases, do not need to reassess the lease classification for any expired or existing leases and do not need to reassess initial direct costs for any existing leases.
Lease and Non-lease Components (elect by class of underlying asset)	Elect as an accounting policy to not separate non-lease components from lease components and instead account for each lease and associated non-lease component as a single lease component.
Short-term Lease (elect by class of underlying asset)	Elect as an accounting policy to not apply the recognition requirements to short-term leases.
Lease term	Elect to use hindsight to determine the lease term.

Evaluation of new lease contracts continues and the process of implementing a compliant lease system solution began in the third quarter of 2017. Management expects the new standard to impact financial position and, at this time, cannot estimate the impact. Management expects no impact to results of operations or cash flows.

Management continues to monitor unresolved industry implementation issues, including items related to easements and right-of-ways, and will analyze the related impacts to lease accounting. In this regard, to address stakeholder concerns about the costs and complexity of complying with the transition provisions of the new lease standard, the FASB issued ASU 2018-01 in January 2018. This ASU provides an optional transition practical expedient that allows companies to exclude in their evaluation of Topic 842 existing or expired land easements that were not previously accounted for as leases under Topic 840, which reduces the volume of contracts requiring evaluation. Management intends to elect this practical expedient upon adoption of ASU 2016-02.

Management continues to monitor FASB's ongoing standard-setting activities that may result in the issuance of additional targeted improvements to the new lease guidance. Management plans to adopt ASU 2016-02 effective January 1, 2019.

ASU 2016-09 "Compensation – Stock Compensation" (ASU 2016-09)

In March 2016, the FASB issued ASU 2016-09 simplifying the accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities and classification on the statements of cash flows. Under the new standard, all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) should be recognized as income tax expense or benefit on the statements of income. Under previous GAAP, excess tax benefits are recognized in additional paid-in capital while tax deficiencies are recognized either as an offset to accumulated excess tax benefits, if any, or on the statements of income.

Management adopted ASU 2016-09 effective January 1, 2017. As a result of the adoption of this guidance, management made an accounting policy election to recognize the effect of forfeitures in compensation cost when they occur. There was an immaterial impact on results of operations and financial position and no impact on cash flows at adoption.

ASU 2016-13 "Measurement of Credit Losses on Financial Instruments" (ASU 2016-13)

In June 2016, the FASB issued ASU 2016-13 requiring an allowance to be recorded for all expected credit losses for financial assets. The allowance for credit losses is based on historical information, current conditions and reasonable and supportable forecasts. The new standard also makes revisions to the other than temporary impairment model for available-for-sale debt securities. Disclosures of credit quality indicators in relation to the amortized cost of financing receivables are further disaggregated by year of origination.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2019, with early adoption permitted for interim and annual periods beginning after December 15, 2018. The amendments will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2016-13 effective January 1, 2020.

ASU 2016-18 "Restricted Cash" (ASU 2016-18)

In November 2016, the FASB issued ASU 2016-18 clarifying the treatment of restricted cash on the statements of cash flows. Under the new standard, amounts considered restricted cash will be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts on the statements of cash flows.

The new accounting guidance is effective for annual periods beginning after December 15, 2017. Early adoption is permitted in any interim or annual period. Management adopted ASU 2016-18 for the 2017 Annual Report.

ASU 2017-07 "Compensation - Retirement Benefits" (ASU 2017-07)

In March 2017, the FASB issued ASU 2017-07 requiring that an employer report the service cost component of pension and postretirement benefits in the same line item or items as other compensation costs. The other components of net benefit cost are required to be presented in the statements of income separately from the service cost component and outside of a subtotal of income from operations. In addition, only the service cost component will be eligible for capitalization as applicable following labor. For 2017, I&M's actual non-service cost components were a credit of $11 million, of which approximately 40% was capitalized.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted as of the beginning of an annual period for which financial statements have not been issued or made available for issuance. Management adopted ASU 2017-07 effective January 1, 2018.

ASU 2017-12 "Derivatives and Hedging" (ASU 2017-12)

In August 2017, the FASB issued ASU 2017-12 amending the recognition and presentation requirements for hedge accounting activities. The objectives are to improve the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements and reduce the complexity of applying hedge accounting. Under the new standard, the concept of recognizing hedge ineffectiveness within the statements of income for cash flow hedges, which has historically been immaterial, will be eliminated. In addition, certain required tabular disclosures relating to fair value and cash flow hedges will be modified.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2018, with early adoption permitted for any interim or annual period after August 2017. Management is analyzing the impact of this new standard, including the possibility of early adoption, and at this time, cannot estimate the impact of adoption on results of operations, financial position or cash flows.

ASU 2018-02 "Reclassification of Certain Tax Effects from AOCI" (ASU 2018-02)

In February 2018, the FASB issued ASU 2018-02 allowing a reclassification from AOCI to Retained Earnings for stranded tax effects resulting from Tax Reform. Under existing accounting guidance for "Income Taxes", deferred tax assets and liabilities must be adjusted for the effect of a change in tax laws or rates with the effect included in income from continuing operations in the reporting period that includes the enactment date. This guidance is applicable for the tax effects of items in AOCI that were originally recognized in Other Comprehensive Income. As a result and absent the new guidance in this ASU, the tax effects of items within AOCI do not reflect the newly enacted corporate tax rate. While the reclassification between AOCI and Retained Earnings is optional under the new guidance, the ASU also requires certain new disclosure requirements regardless of whether the reclassification is made.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2018, with early adoption permitted. The new guidance must be applied either retrospectively to each period (or periods) in which the income tax effects of Tax Reform related to items remaining in AOCI are recognized, or at the beginning of the period of adoption. Management is analyzing the impact of this new standard, including the possibility of early adoption.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the years ended December 31, 2017 and 2016. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 8 for additional details.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

		Pension and OPEB		
	Cash Flow Hedge - Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2016	$ (12.0)	$ 5.1	$ (9.3)	$ (16.2)
Change in Fair Value Recognized in AOCI	—	—	2.8	2.8
Amount of (Gain) Loss Reclassified from AOCI				
Interest on Long-Term Debt	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.9)	—	(0.9)
Amortization of Actuarial (Gains)/Losses	—	0.9	—	0.9
Reclassifications from AOCI, before Income Tax (Expense) Credit	2.0	—	—	2.0
Income Tax (Expense) Credit	0.7	—	—	0.7
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1.3	—	—	1.3
Net Current Period Other Comprehensive Income (Loss)	1.3	—	2.8	4.1
Balance in AOCI as of December 31, 2017	$ (10.7)	$ 5.1	$ (6.5)	$ (12.1)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

		Pension and OPEB		
	Cash Flow Hedge - Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2015	$ (13.3)	$ 5.1	$ (8.5)	$ (16.7)
Change in Fair Value Recognized in AOCI	—	—	(0.8)	(0.8)
Amount of (Gain) Loss Reclassified from AOCI				
Interest on Long-Term Debt	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains)/Losses	—	0.8	—	0.8
Reclassifications from AOCI, before Income Tax (Expense) Credit	2.0	—	—	2.0
Income Tax (Expense) Credit	0.7	—	—	0.7
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1.3	—	—	1.3
Net Current Period Other Comprehensive Income (Loss)	1.3	—	(0.8)	0.5
Balance in AOCI as of December 31, 2016	$ (12.0)	$ 5.1	$ (9.3)	$ (16.2)

4. RATE MATTERS

I&M is involved in rate and regulatory proceedings at the FERC, 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.

Impact of Tax Reform

Rate and regulatory matters are impacted by federal income tax implications. In December 2017, Tax Reform was enacted, which will impact outstanding rate and regulatory matters. For details on the impact of Tax Reform, see Note 12 - Income Taxes.

2017 Indiana Base Rate Case

In July 2017, I&M filed a request with the IURC for a $263 million annual increase in Indiana rates based upon a proposed 10.6% return on common equity with the annual increase to be implemented after June 2018. Upon implementation, this proposed annual increase would be subject to a temporary offsetting $23 million annual reduction to customer bills through December 2018 for a credit adjustment rider related to the timing of estimated in-service dates of certain capital expenditures. The proposed annual increase includes $78 million related to increased annual depreciation rates and an $11 million increase related to the amortization of certain Cook Plant and Rockport Plant regulatory assets. The increase in depreciation rates includes a change in the expected retirement date for Rockport Plant, Unit 1 from 2044 to 2028 combined with increased investment at the Cook Plant, including the Cook Plant Life Cycle Management Project.

In November 2017, various intervenors filed testimony that included annual revenue increase recommendations ranging from $125 million to $152 million. The recommended returns on common equity ranged from 8.65% to 9.1%. In addition, certain parties recommended longer recovery periods than I&M proposed for recovery of regulatory assets and depreciation expenses related to Rockport Plant, Units 1 and 2. In January 2018, in response to a January 2018 IURC request related to the impact of Tax Reform on I&M's pending base rate case, I&M filed updated schedules supporting a $191 million annual increase in Indiana base rates if the effect of Tax Reform was included in the cost of service.

In February 2018, I&M and all parties to the case, except one industrial customer, filed a Stipulation and Settlement Agreement for a $97 million annual increase in Indiana rates effective July 1, 2018 subject to a temporary offsetting reduction to customer bills through December 2018 for a credit rider related to the timing of estimated in-service dates of certain capital expenditures. The one industrial customer agreed to not oppose the Stipulation and Settlement Agreement. The difference between I&M's requested $263 million annual increase and the $97 million annual increase in the Stipulation and Settlement Agreement is primarily due to lower federal income taxes as a result of the reduction in the federal income tax rate due to Tax Reform, the feedback of credits for excess deferred income taxes, a 9.95% return on equity, longer recovery periods of regulatory assets, lower depreciation expense primarily for meters, and an increase in the sharing of off-system sales margins with customers from 50% to 95%. I&M will also refund $4 million from July through December 2018 for the impact of Tax Reform for the period January through June 2018. A hearing at the IURC was held in March 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2017 Michigan Base Rate Case

In May 2017, I&M filed a request with the MPSC for a $52 million annual increase in Michigan base rates based upon a proposed 10.6% return on common equity with the increase to be implemented no later than April 2018. The proposed annual increase includes $23 million related to increased annual depreciation rates and a $4 million increase related to the amortization of certain Cook Plant regulatory assets. The increase in depreciation rates is primarily due to the proposed change in the expected retirement date for Rockport Plant, Unit 1 from 2044 to 2028 combined with increased investment at the Cook Plant related to the Life Cycle Management Project. Additionally, the total proposed increase includes incremental costs related to the Cook Plant Life Cycle Management Program and increased vegetation management expenses.

In October 2017, the MPSC staff and intervenors filed testimony. The MPSC staff recommended an annual net revenue increase of $49 million including proposed retirement dates of 2028 for both Rockport Plant, Units 1 (from 2044) and 2 (from 2022), a reduced capacity charge and a return on common equity of 9.8%. The intervenors proposed certain adjustments to I&M's request including no change to the current 2044 retirement date of Rockport Plant, Unit 1, a market based capacity charge effective February 2019 for up to 10% of I&M's Michigan customers, but did not address an annual net revenue increase. The intervenors' recommended returns on common equity ranged from 9.3% to 9.5%. A hearing at the MPSC was held in November 2017.

In February 2018, an MPSC ALJ issued a Proposal for Decision and recommended an annual revenue increase of $49 million, including the intervenors' proposed capacity charge and staff's depreciation rates for Rockport Plant and a return on common equity of 9.8%. If the maximum 10% of customers choose an alternate supplier starting in February 2019, the estimated annual pretax loss due to the reduced capacity charge is approximately $9 million. An order is expected in the first half of 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Rockport Plant, Unit 2 Selective Catalytic Reduction (SCR)

In October 2016, I&M filed an application with the IURC for approval of a Certificate of Public Convenience and Necessity (CPCN) to install SCR technology at Rockport Plant, Unit 2 by December 2019. The equipment will allow I&M to reduce emissions of NO_X from Rockport Plant, Unit 2 in order for I&M to continue to operate that unit under current environmental requirements. The estimated cost of the SCR project is $274 million, excluding AFUDC, to be shared equally between I&M and AEGCo. As of December 31, 2017, total costs incurred related to this project, including AFUDC, were approximately $23 million. The filing included a request for authorization for I&M to defer its Indiana jurisdictional ownership share of costs including investment carrying costs at a weighted average cost of capital (WACC), depreciation over a 10-year period as provided by statute and other related expenses. I&M proposed recovery of these costs using the existing Clean Coal Technology Rider in a future filing subsequent to approval of the SCR project. The AEGCo ownership share of the proposed SCR project will be billable under the Rockport Unit Power Agreement to I&M and KPCo and will be subject to future regulatory approval for recovery.

In February 2017, the Indiana Office of Utility Consumer Counselor (OUCC) and other parties filed testimony with the IURC. The OUCC recommended approval of the CPCN but also stated that any decision regarding recovery of any under-depreciated plant due to retirement should be fully investigated in a base rate case, not in a tracker or other abbreviated proceeding. The other parties recommended either denial of the CPCN or approval of the CPCN with conditions including a cap on the amount of SCR costs allowed to be recovered in the rider and limitations on other costs related to legal issues involving the Rockport Plant, Unit 2 lease. A hearing at the IURC was held in March 2017. An order from the IURC is pending. In July 2017, I&M filed a motion with the U.S. District Court for the Southern District of Ohio to remove the requirement to install SCR technology at Rockport Plant, Unit 2, which plaintiffs opposed. The district court has delayed the deadline for installation of the SCR technology until June 2020. In January 2018, I&M filed a supplemental motion with the U.S. District Court for the Southern District of Ohio proposing to install the SCR at Rockport Plant, Unit 2 and achieve the final SO_2 emission cap applicable to the plant under the consent decree by the end of 2020, before the expiration of the initial lease term. Responsive filings were filed in February 2018 and a decision is anticipated in the first quarter of 2018.

PJM Transmission Rates

In June 2016, PJM transmission owners, including AEP's eastern transmission subsidiaries and various state commissions filed a settlement agreement at the FERC to resolve outstanding issues related to cost responsibility for charges to transmission customers for certain transmission facilities that operate at or above 500 kV. In July 2016, certain parties filed comments at the FERC contesting the settlement agreement. Upon final FERC approval, PJM would implement a transmission enhancement charge adjustment through the PJM OATT, billable through 2025. Management expects that any refunds received would generally be returned to retail customers through existing state rider mechanisms.

FERC Transmission Complaint - AEP's PJM Participants

In October 2016, seven parties filed a complaint at the FERC that alleged the base return on common equity used by AEP's eastern transmission subsidiaries, including I&M, in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. In November 2017, a FERC order set the matter for hearing and settlement procedures. In March 2018, the AEP eastern transmission companies, including I&M, and six of the complainants filed a settlement agreement with the FERC (the seventh complainant abstained). If approved by the FERC, the settlement agreement (a) establishes a base ROE for AEP's eastern transmission subsidiaries of 9.85% (10.35% inclusive of the RTO incentive adder of 0.5%), effective January 1, 2018, (b) requires the AEP eastern transmission companies to provide a one-time refund of $50 million, attributable from the date of the complaint through December 31, 2017, to be credited to customer bills in the second quarter of 2018 and (c) increases the cap on the equity portion of the capital structure to 55% from 50%. As part of the settlement agreement, AEP's eastern transmission subsidiaries also filed updated transmission formula rates incorporating the reduction in the corporate federal income tax rate from 35% to 21%, effective January 1, 2018 and provides for the amortization of the portion of the excess accumulated deferred income taxes, not subject to the normalization method of accounting, ratably over a ten year period through credits to the federal income tax expense component of the revenue requirement.

Management believes I&M's financial statements adequately address the impact of the settlement agreement. If the FERC orders revenue reductions in excess of the terms of the settlement agreement, it could reduce future net income and cash flows and impact financial condition. A decision from the FERC is pending.

Modifications to AEP's PJM Transmission Rates

In November 2016, AEP's eastern transmission subsidiaries filed an application at the FERC to modify the PJM OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to projected expenses. In March 2017, the FERC accepted the proposed modifications effective January 1, 2017, subject to refund, and set this matter for hearing and settlement procedures. The modified PJM OATT formula rates are based on projected calendar year financial activity and projected plant balances. In December 2017, AEP's eastern transmission subsidiaries filed an uncontested settlement agreement with the FERC resolving all outstanding issues. If the FERC determines that any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

5. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	December 31, 2017	December 31, 2016	Remaining Recovery Period
	(in millions)		
Regulatory Assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Cook Plant Uprate Project	$ 36.3	$ 36.3	
Cook Plant Turbine	15.9	12.8	
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	14.7	8.1	
Rockport Plant Dry Sorbent Injection System - Indiana	10.4	6.6	
Other Regulatory Assets Pending Final Regulatory Approval	2.0	0.9	
Total Regulatory Assets Pending Final Regulatory Approval	79.3	64.7	
Regulatory Assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Under-Recovered Fuel Costs	14.9	12.9	1 year
Cook Plant, Unit 2 Baffle Bolts - Indiana	6.0	6.3	21 years
Other Regulatory Assets Approved for Recovery	1.0	2.5	various
Regulatory Assets Currently Not Earning a Return			
Income Tax Assets	263.9	326.0	33 years
Pension and OPEB Funded Status	77.8	141.9	12 years
Cook Plant Nuclear Refueling Outage Levelization	66.7	75.2	2 years
Deferred PJM Fees	48.0	—	2 years
Postemployment Benefits	9.7	11.4	5 years
Off-system Sales Margin Sharing - Indiana	9.0	24.3	2 years
Medicare Subsidy	7.1	8.2	7 years
Unamortized Loss on Reacquired Debt	1.0	1.2	15 years
Under-Recovered Fuel Costs	—	13.1	
Other Regulatory Assets Approved for Recovery	20.0	16.0	various
Total Regulatory Assets Approved for Recovery	525.1	639.0	
Total FERC Account 182.3 Regulatory Assets	$ 604.4	$ 703.7	

Regulatory Liabilities:	**December 31, 2017**	**December 31, 2016**	**Remaining Refund Period**
	(in millions)		
Regulatory Liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes Liabilities (a)	$ 738.9	$ —	
Total Regulatory Liabilities Pending Final Regulatory Determination	738.9	—	
Regulatory Liabilities approved for payment:			
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	945.0	731.2	(b)
Spent Nuclear Fuel	43.2	44.2	(b)
Over-recovered Fuel Costs	2.7	—	1 year
Income Tax Liabilities	—	23.3	
Other Regulatory Liabilities Approved for Payment	9.1	14.8	various
Total Regulatory Liabilities Approved for Payment	1,000	813.5	
Total FERC 254 Account Regulatory Liabilities	$ 1,738.9	$ 813.5	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. The mechanism and refund period to provide the Excess ADIT to customers will be based on future orders from the respective commission in each jurisdiction. See "Federal Tax Reform" section of Note 12 for additional information.

(b) 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, 2017:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 236.9	$ 269.4	$ 204.6	$ 166.6	$ 877.5
Energy and Capacity Purchase Contracts	125.4	255.9	259.9	352.4	993.6
Total	$ 362.3	$ 525.3	$ 464.5	$ 519.0	$ 1,871.1

(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.

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, 2017, there were no material liabilities recorded for any indemnifications.

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

Lease Obligations

I&M leases certain equipment under master lease agreements. See "Master Lease Agreements" and "Railcar Lease" sections of Note 13 for disclosure of lease residual value guarantees.

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 nonhazardous 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. There are three sites for which I&M received information requests which could lead to PRP designation. I&M has also been named potentially liable at two sites under state law including the I&M site discussed in the next paragraph. 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.

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ. In 2014, I&M recorded an accrual for remediation at certain additional sites in Michigan. As a result of completed remediation work in 2015 and 2017, I&M's accrual was reduced. As of December 31, 2017, I&M's accrual for all of these sites is $100 thousand. The remediation work is expected to be completed in 2018.

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 nonhazardous. 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. At present, management's estimates do not anticipate material cleanup costs for identified Superfund sites.

NUCLEAR CONTINGENCIES

I&M owns and operates the two-unit 2,278 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission (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. 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.

Westinghouse Electric Company Bankruptcy Filing

In March 2017, Westinghouse filed a petition to reorganize under Chapter 11 of the U.S. Bankruptcy Code. It intends to reorganize, not cease business operations. However, it is in the early stages of the bankruptcy process and it is unclear whether the company can successfully reorganize. Westinghouse and I&M have a number of significant ongoing contracts relating to reactor services, nuclear fuel fabrication and ongoing engineering projects. The most significant of these relate to Cook Plant fuel fabrication. Westinghouse has stated that it intends to continue performance on I&M's contracts, but given the importance of upcoming dates in the fuel fabrication process for Cook Plant, and their vital part in Cook Plant's ongoing operations, I&M continues to work with Westinghouse in the bankruptcy proceedings to avoid any interruptions to that service.

In January 2018, Westinghouse issued a news release stating that it intends to sell all of its global business, including the portion of the nuclear business that contracts with Cook Plant. Any sale would require approval by the bankruptcy court. In the unlikely event Westinghouse rejects I&M's contracts, or there is an interference with the sale process, Cook Plant's operations would be significantly impacted and potentially shut down temporarily as I&M seeks other vendors for these services.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The most recent decommissioning cost study was performed in 2015. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste is $1.6 billion in 2015 nondiscounted dollars, with additional ongoing costs of $5 million per year for post decommissioning storage of SNF and an eventual cost of $57 million for the subsequent decommissioning of the spent fuel storage facility, also in 2015 nondiscounted dollars. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were $9 million and $9 million for the years ended December 31, 2017 and 2016, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2017 and 2016, the total decommissioning trust fund balance was $2.2 billion and $1.9 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including interest, unrealized gains and losses and expenses of the trust funds) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining 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 continues to increase and cannot be recovered.

SNF 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 Department of Energy (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 zero. As of December 31, 2017 and 2016, fees and related interest of $269 million and $266 million, respectively, for fuel consumed prior to April 7, 1983 have been recorded as Other Long-term Debt and funds collected from customers along with related earnings totaling $312 million and $311 million, respectively, to pay the fee are 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 delays in accepting SNF for permanent storage. Under the settlement agreement, I&M received $22 million and $6 million in 2017 and 2016, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2019. The proceeds reduced costs for dry cask storage. As of December 31, 2017, I&M has deferred $11 million in Miscellaneous Current and Accrued Assets and $5 million in Miscellaneous Deferred Debits on the balance sheets of 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 11 for disclosure of the fair value of assets within the trusts.

Nuclear Insurance

I&M carries insurance coverage in the amount of $3 billion for a nuclear incident at the Cook Plant for decontamination, stabilization and extraordinary incidents caused by premature decommissioning. Insurance coverage for a nonnuclear property incident at the Cook Plant is $1.5 billion. 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 $51 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 at $13.4 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 $450 million of 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 $127 million on each licensed reactor in the U.S. payable in annual installments of $19 million. As a result, I&M could be assessed $255 million per nuclear incident payable in annual installments of $38 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 $450 million through commercially available insurance. The next level of liability coverage of up to $13 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 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 cyber security 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 of this footnote for a discussion of I&M's nuclear exposures and related insurance.

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 cyber security 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.

Rockport Plant Litigation

In July 2013, the Wilmington Trust Company filed a complaint in U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiffs further allege that the defendants' actions constitute breach of the lease and participation agreement. The plaintiffs seek a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M.

In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiffs' claims, including the dismissal without prejudice of plaintiffs' claims seeking compensatory damages. Several claims remained, including the claim for breach of the participation agreement and a claim alleging breach of an implied covenant of good faith and fair dealing. In June 2015, AEGCo and I&M filed a motion for partial judgment on the claims seeking dismissal of the breach of participation agreement claim as well as any claim for indemnification of costs associated with this case. The plaintiffs subsequently filed an amended complaint to add another claim under the lease and also filed a motion for partial summary judgment. In November 2015, AEGCo and I&M filed a motion to strike the plaintiffs' motion for partial judgment and filed a motion to dismiss the case for failure to state a claim.

In March 2016, the court entered an opinion and order in favor of AEGCo and I&M, dismissing certain of the plaintiffs' claims for breach of contract and dismissing claims for breach of implied covenant of good faith and fair dealing, and further dismissing plaintiffs' claim for indemnification of costs. By the same order, the court permitted plaintiffs to move forward with their claim that AEGCo and I&M failed to exercise prudent utility practices in the maintenance and operation of Rockport Plant, Unit 2. In April 2016, the plaintiffs filed a notice of voluntary dismissal of all remaining claims with prejudice and the court subsequently entered a final judgment. In May 2016, plaintiffs filed an appeal in the U.S. Court of Appeals for the Sixth Circuit on whether AEGCo and I&M are in breach of certain contract provisions that plaintiffs allege operate to protect the plaintiffs' residual interests in the unit and whether the trial court erred in dismissing plaintiffs' claims that AEGCo and I&M breached the covenant of good faith and fair dealing.

In April 2017, the U.S. Court of Appeals for the Sixth Circuit issued an opinion reversing the district court's decisions which had dismissed certain of plaintiffs' claims for breach of contract and remanding the case to the district court to enter summary judgment in plaintiffs' favor consistent with that ruling. In April 2017, AEGCo and I&M filed a petition for rehearing with the U.S. Court of Appeals for the Sixth Circuit, which was granted. In June 2017, the U.S. Court of Appeals for the Sixth Circuit issued an amended opinion and judgment which reverses the district court's dismissal of certain of the owners' claims under the lease agreements, vacates the denial of the owners' motion for partial summary judgment and remands the case to the district court for further proceedings. The amended opinion and judgment also affirms the district court's dismissal of the owners' breach of good faith and fair dealing claim as duplicative of the breach of contract claims and removes the instruction to the district court in the original opinion to enter summary judgment in favor of the owners.

In July 2017, AEP filed a motion with the U.S. District Court for the Southern District of Ohio in the original NSR litigation, seeking to modify the consent decree to eliminate the obligation to install certain future controls at Rockport Plant, Unit 2 if AEP does not acquire ownership of that Unit, and to modify the consent decree in other respects to preserve the environmental benefits of the consent decree. In November 2017, the district court granted the owners' unopposed motion to stay the lease litigation to afford time for resolution of AEP's motion to modify the consent decree.

Management will continue to defend against the claims. Given that the district court dismissed plaintiffs' claims seeking compensatory relief as premature, and that plaintiffs have yet to present a methodology for determining or any analysis supporting any alleged damages, management is unable to determine a range of potential losses that are reasonably possible of occurring.

7. DISPOSITION

Tanners Creek Plant

In October 2016, I&M sold its retired Tanners Creek Plant site including its associated AROs to a nonaffiliated party. I&M paid $92 million and the nonaffiliated party took ownership of the Tanners Creek plant site assets and assumed responsibility for environmental liabilities and AROs, including ash pond closure, asbestos abatement and decommissioning and demolition. I&M did not record a gain or loss related to this sale and will address recovery of Tanners Creek deferred costs in future rate proceedings. If any of the costs associated with Tanners Creek are not recoverable, it could reduce future net income and impact financial condition.

8. BENEFIT PLANS

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 an unfunded nonqualified pension plan. 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 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 ratemaking 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 benefit obligations are shown in the following table:

	Pension Plans		OPEB	
	December 31,			
Assumptions	**2017**	**2016**	**2017**	**2016**
Discount Rate	3.65 %	4.05%	3.60%	4.10%
Rate of Compensation Increase	4.85 % (a)	4.80% (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 2017, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 12% 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:

	Pension Plans		OPEB	
	Years Ended December 31,			
Assumptions	**2017**	**2016**	**2017**	**2016**
Discount Rate	4.05 %	4.30%	4.10%	4.30%
Expected Return on Plan Assets	6.00 %	6.00%	6.75%	7.00%
Rate of Compensation Increase	4.85 % (a)	4.80% (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:

	December 31,	
Health Care Trend Rates	**2017**	**2016**
Initial	6.50%	7.00%
Ultimate	5.00%	5.00%
Year Ultimate Reached	2024	2024

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 0.2	$ (0.2)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	3.7	(3.4)

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, 2017, 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 and Funded Status

The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets and funded status. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans		OPEB	
	2017	**2016**	**2017**	**2016**
Change in Benefit Obligation	**(in millions)**			
Benefit Obligation as of January 1,	$ 611.6	$ 591.5	$ 167.6	$ 166.3
Service Cost	14.0	12.2	1.6	1.5
Interest Cost	24.3	25.3	6.9	7.0
Actuarial (Gain) Loss	10.8	20.1	(12.0)	3.8
Benefit Payments	(36.4)	(37.5)	(15.6)	(15.7)
Participant Contributions	—	—	4.9	4.6
Medicare Subsidy	—	—	0.1	0.1
Benefit Obligation as of December 31,	$ 624.3	$ 611.6	$ 153.5	$ 167.6
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 586.1	$ 570.0	$ 186.6	$ 189.0
Actual Gain on Plan Assets	74.0	40.6	35.2	8.7
Company Contributions	13.0	13.0	—	—
Participant Contributions	—	—	4.9	4.6
Benefit Payments	(36.4)	(37.5)	(15.6)	(15.7)
Fair Value of Plan Assets as of December 31,	$ 636.7	$ 586.1	$ 211.1	$ 186.6
Funded (Underfunded) Status as of December 31,	$ 12.4	$ (25.5)	$ 57.6	$ 19.0

Amounts Recognized on the Balance Sheets

	Pension Plans		OPEB	
	December 31,			
	2017	2016	2017	2016
	(in millions)			
Special Funds – Prepaid Benefit Costs	$ 13.4	$ —	$ 57.6	$ 19.0
Accumulated Provision for Pensions and Benefits – Long-term Benefit Liability	(1.0)	(25.5)	—	—
Funded (Underfunded) Status	$ 12.4	$ (25.5)	$ 57.6	$ 19.0

Amounts Included in AOCI, Income Tax Expense and Regulatory Assets

	Pension Plans		OPEB	
	December 31,			
	2017	2016	2017	2016
Components	(in millions)			
Net Actuarial Loss	$ 94.9	$ 133.2	$ 42.0	$ 81.3
Prior Service Cost (Credit)	—	0.2	(56.9)	(66.3)
Recorded as				
Regulatory Assets	$ 91.8	$ 128.2	$ (14.0)	$ 13.7
Deferred Income Taxes	0.7	1.8	(0.2)	0.5
Net of Tax AOCI	2.0	3.4	(0.6)	0.8
Income Tax Expense (a)	0.4	—	(0.1)	—

(a) Amounts relate to the re-measurement of Deferred Income Taxes as a result of Tax Reform. In accordance with the accounting guidance for "Income Taxes", re-measurement of Deferred Income Taxes related to AOCI must flow through the statement of income.

Components of the change in amounts included in AOCI, Income Tax Expense and Regulatory Assets are as follows:

	Pension Plans		OPEB	
	2017	2016	2017	2016
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ (28.6)	$ 13.2	$ (34.9)	$ 7.9
Amortization of Actuarial Loss	(9.7)	(10.0)	(4.4)	(3.7)
Amortization of Prior Service Credit (Cost)	(0.2)	(0.1)	9.4	9.4
Change for the Year Ended December 31,	$ (38.5)	$ 3.1	$ (29.9)	$ 13.6

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		OPEB	
December 31,			
2017	2016	2017	2016
12.3%	12.1%	12.2%	12.1%

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2017:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 318.6	$ —	$ —	$ —	$ 318.6	6.2 %
International	507.7	—	—	—	507.7	9.8 %
Options	—	26.9	—	—	26.9	0.5 %
Common Collective Trusts (c)	—	—	—	452.9	452.9	8.7 %
Subtotal – Equities	826.3	26.9	—	452.9	1,306.1	25.2 %
Fixed Income:						
United States Government and Agency Securities	—	1,376.5	—	—	1,376.5	26.6 %
Corporate Debt	—	1,277.0	—	—	1,277.0	24.7 %
Foreign Debt	—	296.9	—	—	296.9	5.7 %
State and Local Government	—	31.7	—	—	31.7	0.6 %
Other – Asset Backed	—	10.2	—	—	10.2	0.2 %
Subtotal – Fixed Income	—	2,992.3	—	—	2,992.3	57.8 %
Infrastructure (c)	—	—	—	59.5	59.5	1.2 %
Real Estate (c)	—	—	—	290.3	290.3	5.6 %
Alternative Investments (c)	—	—	—	446.0	446.0	8.6 %
Securities Lending	—	501.8	—	—	501.8	9.7 %
Securities Lending Collateral (a)	—	—	—	(503.5)	(503.5)	(9.7)%
Cash and Cash Equivalents (c)	0.4	35.6	—	21.2	57.2	1.1 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	24.4	24.4	0.5 %
Total	$ 826.7	$ 3,556.6	$ —	$ 790.8	$ 5,174.1	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

The following table sets forth a reconciliation of changes in the fair value of AEP's assets classified as Level 3 in the fair value hierarchy for the pension assets:

	Infrastructure	Real Estate	Alternative Investments	Total Level 3
	(in millions)			
Balance as of January 1, 2017	$ 57.6	$ 254.9	$ 411.1	$ 723.6
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	—	—	—	—
Relating to Assets Sold During the Period	—	—	—	—
Purchases and Sales	—	—	—	—
Transfers into Level 3	—	—	—	—
Transfers out of Level 3 (a)	(57.6)	(254.9)	(411.1)	(723.6)
Balance as of December 31, 2017	$ —	$ —	$ —	$ —

(a) The classification of Level 3 assets from the prior year was corrected in the current year presentation and included within the fair value hierarchy table as of December 31, 2017 as "Other" investments for which fair value is measured using net asset value per share in accordance with ASU 2015-07, Disclosure for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent). Management concluded that these disclosure errors were immaterial individually and in the aggregate to all prior periods presented.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2017:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 307.1	$ —	$ —	$ —	$ 307.1	17.7 %
International	306.9	—	—	—	306.9	17.7 %
Options	—	9.4	—	—	9.4	0.5 %
Common Collective Trusts (b)	—	—	—	153.6	153.6	8.9 %
Subtotal – Equities	614.0	9.4	—	153.6	777.0	44.8 %
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	185.0	185.0	10.7 %
United States Government and Agency Securities	—	187.4	—	—	187.4	10.8 %
Corporate Debt	—	214.1	—	—	214.1	12.4 %
Foreign Debt	—	40.7	—	—	40.7	2.4 %
State and Local Government	49.7	16.8	—	—	66.5	3.8 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	49.7	459.2	—	185.0	693.9	40.1 %
Trust Owned Life Insurance:						
International Equities	—	105.4	—	—	105.4	6.1 %
United States Bonds	—	118.2	—	—	118.2	6.8 %
Subtotal – Trust Owned Life Insurance	—	223.6	—	—	223.6	12.9 %
Cash and Cash Equivalents (b)	36.7	—	—	4.2	40.9	2.4 %
Other – Pending Transactions and Accrued Income (a)	—	—	—	(2.9)	(2.9)	(0.2)%
Total	$ 700.4	$ 692.2	$ —	$ 339.9	$ 1,732.5	100.0 %

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

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2016:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 357.8	$ —	$ —	$ —	$ 357.8	7.4 %
International	439.2	—	—	—	439.2	9.1 %
Options	—	20.0	—	—	20.0	0.4 %
Common Collective Trusts (c)	—	14.0	—	400.5	414.5	8.6 %
Subtotal – Equities	797.0	34.0	—	400.5	1,231.5	25.5 %
Fixed Income:						
Common Collective Trust – Debt (c)	—	—	—	32.3	32.3	0.7 %
United States Government and Agency Securities (c)	—	423.3	—	17.7	441.0	9.1 %
Corporate Debt (c)	—	1,932.2	—	10.0	1,942.2	40.2 %
Foreign Debt (c)	—	373.7	—	12.1	385.8	8.0 %
State and Local Government	—	11.5	—	—	11.5	0.2 %
Other – Asset Backed (c)	—	5.4	—	7.4	12.8	0.3 %
Subtotal – Fixed Income	—	2,746.1	—	79.5	2,825.6	58.5 %
Infrastructure	—	—	57.6	—	57.6	1.2 %
Real Estate	—	—	254.9	—	254.9	5.3 %
Alternative Investments	—	—	411.1	—	411.1	8.5 %
Securities Lending	—	161.6	—	—	161.6	3.4 %
Securities Lending Collateral (a)	—	—	—	(163.3)	(163.3)	(3.4)%
Cash and Cash Equivalents (c)	—	—	—	29.7	29.7	0.6 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	18.6	18.6	0.4 %
Total	$ 797.0	$ 2,941.7	$ 723.6	$ 365.0	$ 4,827.3	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay collateral received as part of the Securities Lending Program.

(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

The following table sets forth a reconciliation of changes in the fair value of AEP's assets classified as Level 3 in the fair value hierarchy for the pension assets:

	Foreign Debt	Infrastructure	Real Estate	Alternative Investments	Total Level 3
			(in millions)		
Balance as of January 1, 2016	$ 0.1	$ 42.0	$ 253.7	$ 378.7	$ 674.5
Actual Return on Plan Assets					
Relating to Assets Still Held as of the Reporting Date	—	5.9	5.3	13.7	24.9
Relating to Assets Sold During the Period	—	0.9	23.2	21.1	45.2
Purchases and Sales	(0.1)	8.8	(27.3)	(2.4)	(21.0)
Transfers into Level 3	—	—	—	—	—
Transfers out of Level 3	—	—	—	—	—
Balance as of December 31, 2016	$ —	$ 57.6	$ 254.9	$ 411.1	$ 723.6

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2016:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 517.1	$ —	$ —	$ —	$ 517.1	33.5 %
International	435.5	—	—	—	435.5	28.2 %
Options	—	15.2	—	—	15.2	1.0 %
Common Collective Trusts (b)	—	10.9	—	20.5	31.4	2.0 %
Subtotal – Equities	952.6	26.1	—	20.5	999.2	64.7 %
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	93.7	93.7	6.0 %
United States Government and Agency Securities	—	64.7	—	—	64.7	4.2 %
Corporate Debt	—	121.6	—	—	121.6	7.9 %
Foreign Debt	—	18.6	—	—	18.6	1.2 %
State and Local Government	—	3.0	—	—	3.0	0.2 %
Other – Asset Backed	—	5.9	—	—	5.9	0.4 %
Subtotal – Fixed Income	—	213.8	—	93.7	307.5	19.9 %
Trust Owned Life Insurance:						
International Equities (b)	—	—	—	110.1	110.1	7.1 %
United States Bonds (b)	—	—	—	97.4	97.4	6.3 %
Subtotal – Trust Owned Life Insurance	—	—	—	207.5	207.5	13.4 %
Cash and Cash Equivalents	24.0	10.5	—	—	34.5	2.2 %
Other – Pending Transactions and Accrued Income (a)	—	—	—	(2.8)	(2.8)	(0.2)%
Total	$ 976.6	$ 250.4	$ —	$ 318.9	$ 1,545.9	100.0 %

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

Accumulated Benefit Obligation

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

Accumulated Benefit Obligation	Underfunded Pension Plans December 31, 2017	Underfunded Pension Plans December 31, 2016
	(in millions)	
Qualified Pension Plan	$ 592.4	$ 588.5
Nonqualified Pension Plans	0.4	0.3
Total	$ 592.8	$ 588.8

For the underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets of these plans were as follows:

	December 31, 2017	December 31, 2016
	(in millions)	
Projected Benefit Obligation	$ 1.0	$ 611.6
Accumulated Benefit Obligation	$ 0.4	$ 588.8
Fair Value of Plan Assets	—	586.1
Underfunded Accumulated Benefit Obligation	$ (0.4)	$ (2.7)

Estimated Future Benefit Payments and Contributions

I&M expects contributions and payments for the pension plans of $2 million during 2018. 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 pension benefits and OPEB are as follows:

	Estimated Payments	
	Pension Plans	OPEB
	(in millions)	
2018	$ 35.1	$ 14.9
2019	37.2	14.9
2020	37.6	15.0
2021	38.7	15.2
2022	40.4	15.2
Years 2023 to 2027, in Total	210.8	74.8

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,			
	2017	2016	2017	2016
	(in millions)			
Service Cost	$ 14.0	$ 12.2	$ 1.6	$ 1.5
Interest Cost	24.3	25.3	6.9	7.0
Expected Return on Plan Assets	(34.6)	(33.6)	(12.2)	(12.9)
Amortization of Prior Service Cost (Credit)	0.2	0.1	(9.4)	(9.4)
Amortization of Net Actuarial Loss	9.7	10.0	4.4	3.7
Net Periodic Benefit Cost (Credit)	13.6	14.0	(8.7)	(10.1)
Capitalized Portion	(5.5)	(3.3)	3.5	2.4
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 8.1	$ 10.7	$ (5.2)	$ (7.7)

Estimated amounts expected to be amortized to net periodic benefit costs (credits) and the impact on the balance sheet during 2018 are shown in the following table:

Components	Pension Plans	OPEB
	(in millions)	
Net Actuarial Loss	$ 10.1	$ 1.0
Prior Service Cost (Credit)	—	(9.4)
Total Estimated 2018 Amortization	$ 10.1	$ (8.4)
Expected to be Recorded as		
Regulatory Asset	$ 9.5	$ (7.6)
Deferred Income Taxes	0.1	(0.2)
Net of Tax AOCI	0.5	(0.6)
Total	$ 10.1	$ (8.4)

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. 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, 2017 and 2016 was $11 million and $11 million, respectively.

9. BUSINESS SEGMENTS

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

10. 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 a 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, credit risk and foreign currency exchange 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	Volume December 31, 2017	Volume December 31, 2016	Unit of Measure
	(in millions)		
Commodity:			
Power	38.5	19.9	MWhs
Coal	2.0	0.5	Tons
Natural Gas	0.7	—	MMBtus
Heating Oil and Gasoline	0.7	0.7	Gallons
Interest Rate	$ —	$ 0.1	USD

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.

At times, I&M is exposed to foreign currency exchange rate risks primarily when some fixed assets are purchased from foreign suppliers. In accordance with AEP's risk management policy, I&M may utilize foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. I&M does not hedge all foreign currency 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 sheet 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, supply and demand market data and 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 is required to post or receive cash collateral based on third party contractual agreements and risk profiles. The netted cash collateral from third parties against short-term and long-term risk management assets and netted cash collateral paid to third parties against short-term and long-term risk management liabilities were immaterial for the years ended December 31, 2017 and 2016.

The following tables represent the gross fair value of derivative activity on the balance sheets:

Fair Value of Derivative Instruments
December 31, 2017

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	$ 48.8	$ (40.5)	$ 8.3
Long-term Portion of Derivative Instrument Assets	1.6	(0.9)	0.7
Derivative Instrument Liabilities	49.4	(45.8)	3.6
Long-term Portion of Derivative Instrument Liabilities	0.9	(0.8)	0.1

Fair Value of Derivative Instruments
December 31, 2016

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	$ 16.0	$ (12.5)	$ 3.5
Long-term Portion of Derivative Instrument Assets	1.1	(1.1)	—
Derivative Instrument Liabilities	13.7	(12.6)	1.1
Long-term Portion of Derivative Instrument Liabilities	1.9	(1.1)	0.8

(a) Derivative instruments within this category are reported 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) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not 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, 2017	2016
	(in millions)	
Operating Revenues	$ 5.3	$ 9.9
Operation Expenses	0.8	0.1
Regulatory Assets (a)	(7.4)	3.1
Regulatory Liabilities (a)	15.9	13.9
Total Gain on Risk Management Contracts	$ 14.6	$ 27.0

(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 statement 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 expense line item on the statements of income as that of the associated risk. 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 effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income on the balance sheet until the period the hedged item affects Net Income. I&M's hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

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 regulatory assets or regulatory liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During 2017 and 2016, 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 2017 and 2016, I&M did not apply cash flow hedging to outstanding interest rate derivatives.

The accumulated gains or losses related foreign currency hedges are reclassified from Accumulated Other Comprehensive Income on the balance sheets into Depreciation Expense on the statements of income over the depreciable lives of the fixed assets designated as the hedged items into qualifying foreign currency hedging relationships. During the years ended December 31, 2017 and 2016, I&M did not apply cash flow hedging to any outstanding foreign currency derivatives.

During 2017 and 2016, hedge ineffectiveness was immaterial or nonexistent for all of the hedge strategies disclosed above.

For details on effective cash flow hedges included in Accumulated Other Comprehensive Income on the balance sheets and the reasons for changes in cash flow hedges, see Note 3.

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, 2017		December 31, 2016	
Interest Rate and Foreign Currency			
AOCI Gain (Loss) Net of Tax	Expected to be Reclassed to Net Income During the Next Twelve Months	AOCI Gain (Loss) Net of Tax	Expected to be Reclassed to Net Income During the Next Twelve Months
(in millions)			
$ (10.7)	$ (1.3)	$ (12.0)	$ (1.3)

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 Moody's Investors Service Inc., S&P Global Inc. 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. A counterparty is required 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.

Collateral Triggering Events

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 immaterial derivative contracts with collateral triggering events in a net liability position as of December 31, 2017 and 2016.

Cross-Default Triggers

In addition, a majority of I&M's 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. Amounts for I&M are immaterial for years ended December 31, 2017 and 2016.

11. 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,			
2017		2016	
Book Value	Fair Value	Book Value	Fair Value
(in millions)			
$ 2,569.4	$ 2,826.1	$ 2,230.1	$ 2,410.3

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.

The following is a summary of nuclear trust fund investments:

	December 31,					
	2017			2016		
	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 17.2	$ —	$ —	$ 18.7	$ —	$ —
Fixed Income Securities:						
United States Government	981.2	29.7	(3.6)	785.4	27.1	(5.5)
Corporate Debt	58.7	3.8	(1.2)	60.9	2.3	(1.4)
State and Local Government	8.8	0.8	(0.2)	121.1	0.4	(0.7)
Subtotal Fixed Income Securities	1,048.7	34.3	(5.0)	967.4	29.8	(7.6)
Equity Securities – Domestic	1,461.7	868.2	(75.5)	1,270.1	677.9	(79.6)
Spent Nuclear Fuel and Decommissioning Trusts	$ 2,527.6	$ 902.5	$ (80.5)	$ 2,256.2	$ 707.7	$ (87.2)

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

	Years Ended December 31, 2017	Years Ended December 31, 2016
	(in millions)	
Proceeds from Investment Sales	$ 2,256.3	$ 2,957.7
Purchases of Investments	2,300.5	3,000.0
Gross Realized Gains on Investment Sales	200.7	46.1
Gross Realized Losses on Investment Sales	146.0	24.4

The base cost of fixed income securities was $1 billion and $938 million as of December 31, 2017 and 2016, respectively. The base cost of equity securities was $594 million and $592 million as of December 31, 2017 and 2016, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2017 is as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 387.3
After 1 year through 5 years	287.4
After 5 years through 10 years	204.4
After 10 years	169.6
Total	$ 1,048.7

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.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (b)	$ —	$ 39.4	$ 9.1	$ (40.2)	$ 8.3
Other Special Funds					
Cash and Cash Equivalents (c)	7.5	—	—	9.7	17.2
Fixed Income Securities:					
United States Government	—	981.2	—	—	981.2
Corporate Debt	—	58.7	—	—	58.7
State and Local Government	—	8.8	—	—	8.8
Subtotal Fixed Income Securities	—	1,048.7	—	—	1,048.7
Equity Securities – Domestic (d)	1,461.7	—	—	—	1,461.7
Total Other Special Funds	1,469.2	1,048.7	—	9.7	2,527.6
Total Assets	$ 1,469.2	$ 1,088.1	$ 9.1	$ (30.5)	$ 2,535.9
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a) (b)	$ —	$ 47.6	$ 1.5	$ (45.5)	$ 3.6

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (b)	$ —	$ 12.8	$ 3.0	$ (12.3)	$ 3.5
Other Special Funds					
Cash and Cash Equivalents (c)	7.3	—	—	11.4	18.7
Fixed Income Securities:					
United States Government	—	785.4	—	—	785.4
Corporate Debt	—	60.9	—	—	60.9
State and Local Government	—	121.1	—	—	121.1
Subtotal Fixed Income Securities	—	967.4	—	—	967.4
Equity Securities – Domestic (d)	1,270.1	—	—	—	1,270.1
Total Other Special Funds	1,277.4	967.4	—	11.4	2,256.2
Total Assets	$ 1,277.4	$ 980.2	$ 3.0	$ (0.9)	$ 2,259.7
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a) (b)	$ —	$ 13.3	$ 0.2	$ (12.4)	$ 1.1

(a) 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."
(b) Substantially comprised of power contracts.
(c) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 1 amounts primarily represent investments in money market funds.
(d) Amounts represent publicly traded equity securities and equity-based mutual funds.

There were no transfers between Level 1 and Level 2 during the years ended December 31, 2017 and 2016.

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, 2017	**Net Risk Management Assets (Liabilities)**
	(in millions)
Balance as of December 31, 2016	$ 2.8
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	4.0
Settlements	(7.1)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	7.9
Balance as of December 31, 2017	$ 7.6

Year Ended December 31, 2016	**Net Risk Management Assets (Liabilities)**
	(in millions)
Balance as of December 31, 2015	$ 4.3
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	7.1
Settlements	(11.1)
Transfers out of Level 3 (c)	0.1
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	2.4
Balance as of December 31, 2016	$ 2.8

(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) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.

(d) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory assets/liabilities or accounts payable.

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

Significant Unobservable Inputs
December 31, 2017

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	**Liabilities**	**Technique**	**Input (a)**	**Low**	**High**	**Weighted Average**
	(in millions)						
Energy Contracts	$ 0.5	$ 0.3	Discounted Cash Flow	Forward Market Price	$ 20.52	$ 195.00	$ 33.80
FTRs	8.6	1.2	Discounted Cash Flow	Forward Market Price	(0.36)	5.75	0.86
Total	$ 9.1	$ 1.5					

Significant Unobservable Inputs
December 31, 2016

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	**Liabilities**	**Technique**	**Input (a)**	**Low**	**High**	**Weighted Average**
	(in millions)						
Energy Contracts	$ 0.3	$ 0.2	Discounted Cash Flow	Forward Market Price	$ 19.68	$ 48.55	$ 36.34
FTRs	2.7	—	Discounted Cash Flow	Forward Market Price	(7.90)	8.91	1.32
Total	$ 3.0	$ 0.2					

(a) Represents market prices in dollars per MWh.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs as of December 31, 2017 and 2016:

Sensitivity 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)

12. INCOME TAXES

Federal Tax Reform

In December 2017, legislation referred to as Tax Reform was signed into law. Substantially all of the provisions in the new legislation are effective for taxable years beginning after December 31, 2017. Tax Reform includes significant changes to the Internal Revenue Code of 1986 (as amended, the Code), including amendments which significantly change the taxation of business entities and also includes provisions specific to regulated public utilities. The more significant changes that affect I&M include the reduction in the corporate federal income tax rate from 35% to 21%, and several technical provisions including, among others, limiting the utilization of net operating losses arising after December 31, 2017 to 80% of taxable income with an indefinite carryforward period. The Tax Reform provisions related to regulated public utilities generally allow for the continued deductibility of interest expense, eliminate bonus depreciation for certain property acquired after September 27, 2017 and continue certain rate normalization requirements for accelerated depreciation benefits.

Provisional Amounts

Given the significance of the legislative changes resulting from Tax Reform, the timing of its enactment, and the widespread applicability to registrants, the SEC staff recognized the potential challenges faced by registrants when reflecting the effects of Tax Reform in their 2017 financial statements. Accordingly, in order to address potential uncertainty or diversity of views in practice regarding the application of the accounting guidance for "Income Taxes" in situations where a registrant does not have the necessary information available, prepared, or analyzed (including computations) in reasonable detail to complete the accounting for "Income Taxes" for certain tax effects of Tax Reform for the reporting period in which the legislation was enacted, the SEC staff issued Staff Accounting Bulletin 118 (SAB 118) in December 2017. For such areas of analysis that are incomplete, SAB 118 provides for up to a one year period in which to complete the required analyses and accounting required by the accounting guidance for "Income Taxes," referred to as the measurement period.

If applied, SAB 118 describes three categories associated with a registrant's status of accounting for Tax Reform during the measurement period: (a) a registrant is complete with its accounting for certain effects of Tax Reform, (b) a registrant's accounting is incomplete but is able to determine a reasonable estimate for certain effects of Tax Reform and records that estimate as a provisional amount, or (c) the accounting is incomplete and a registrant is not able to determine a reasonable estimate and therefore continues to apply existing accounting guidance for income taxes, based on the provisions of the tax laws that were in effect immediately prior to the enactment of the Tax Reform legislation. For items in which the accounting assessment is complete, a registrant must reflect the income tax effects of Tax Reform for those items in its financial statements that include the enactment of the Tax Reform legislation. SAB 118 also requires certain disclosures to provide information about the material financial reporting impacts, if any, due to Tax Reform for which the accounting is not complete. Subsequent disclosures in future reporting periods in which the accounting is completed are also a requirement of the guidance.

I&M has completed or has made a reasonable estimate for the measurement and accounting of certain effects of Tax Reform which have been reflected in the December 31, 2017 financial statements. The adjustments to deferred tax assets and liabilities are provisional amounts that are based on the best available information as of December 31, 2017. While I&M was able to make reasonable estimates of the impact of Tax Reform, the final impact may differ from the recorded provisional amounts to the extent refinements are made to the estimated cumulative temporary differences or as a result of additional guidance or technical corrections that may be issued by the IRS that may impact management's interpretation and assumptions utilized. I&M expects to complete the analysis of the provisional items during the second half of 2018.

Impact of Tax Reform on the Financial Statements

Changes in the Code due to Tax Reform had a material impact on I&M's 2017 financial statements. In accordance with the accounting guidance for "Income Taxes", the effect of a change in tax law must be recognized at the date of enactment. The accounting guidance for "Income Taxes" also requires deferred tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences will be realized or settled. As a result, I&M's deferred tax assets and liabilities were re-measured using the newly enacted tax rate of 21% in December 2017. This re-measurement resulted in a significant reduction in I&M's net accumulated deferred income tax liability. The reduction of the net accumulated deferred income tax liability was primarily offset by a corresponding decrease in income tax related regulatory assets and an increase in income tax related regulatory liabilities because the benefit of the lower federal tax rate is expected to be provided to customers. For I&M's nonutility operations, the re-measurement of deferred taxes arising from those operations was recorded as an adjustment to income tax expense.

I&M reflected a decrease in Deferred Income Tax Liabilities of $810.0 million and resulted in an increase in income tax related Regulatory Liabilities of $716.4 million, a decrease in income tax related Regulatory Assets of $94.6 million and an increase to Income Tax Expense of $1.0 million.

Regulatory Treatment

As a result of Tax Reform, I&M recognized a net regulatory liability for approximately $575 million of Excess Accumulated Deferred Income Taxes (ADIT), as well as an incremental liability of $153 million to reflect the $575 million Excess ADIT on a pre-tax basis, which is presented in Other Regulatory Liabilities on the balance sheets. The Excess ADIT is reflected on a pre-tax basis to appropriately contemplate future tax consequences in the periods when the net regulatory liability is settled. Approximately $372 million of the Excess ADIT relates to temporary differences associated with depreciable property. The Tax Reform legislation includes certain rate normalization requirements that stipulate how the portion of the total Excess ADIT that is related to certain depreciable property must be passed back to customers. Specifically, for I&M is subject to those rate normalization requirements, Excess ADIT resulting from the reduction of the corporate tax rate with respect to prior depreciation or recovery deductions on property placed in service before December 22, 2017, will be normalized using the average rate assumption method. As a result, once the amortization of Excess ADIT related to depreciable property begins, customers will receive the benefits over the remaining weighted average useful life of the applicable property.

For the remaining $202 million of Excess ADIT, I&M expects to continue working with the IURC and the MPSC to determine the appropriate mechanism and time period over which to provide the benefits of Tax Reform to customers.

I&M expects the mechanism and time period to provide the benefits of Tax Reform to customers will reduce future cash flows and may impact financial condition, but is not expected to have a material impact on future net income.

State Regulatory Matters

The IURC and MPSC have recently issued orders requiring public utilities, including I&M, to record regulatory liabilities to reflect the corporate federal income taxes currently collected in utility rates in excess of the enacted corporate federal income tax rate of 21% beginning January 1, 2018. See Note 4 - Rate Matters for additional information regarding state utility commission orders received.

Income Tax Expense

The details of income tax expense as reported are as follows:

	Years Ended December 31, 2017	2016
	(in millions)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ (116.6)	$ (37.5)
Deferred	196.9	105.8
Deferred Investment Tax Credits	(4.7)	3.8
Total	75.6	72.1
Charged (Credited) to Nonoperating Income, Net:		
Current	1.9	(3.9)
Deferred	4.1	2.9
Total	6.0	(1.0)
Total Income Taxes	$ 81.6	$ 71.1

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, 2017	2016
	(in millions)	
Net Income	$ 186.8	$ 239.9
Income Tax Expense	81.6	71.1
Pretax Income	$ 268.4	$ 311.0
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 93.9	$ 108.8
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
Depreciation	11.4	6.7
AFUDC	(5.6)	(7.3)
Removal Costs	(13.2)	(21.2)
Investment Tax Credits, Net	(4.7)	(4.7)
State and Local Income Taxes, Net	(6.2)	2.3
Tax Adjustments	2.4	(14.2)
Tax Reform Adjustments	2.3	—
Other	1.3	0.7
Income Tax Expense	$ 81.6	$ 71.1
Effective Income Tax Rate	30.4%	22.9%

Net Deferred Tax Liability

The following table shows elements of I&M's net deferred tax liability and significant temporary differences:

	December 31,	
	2017	**2016**
	(in millions)	
Deferred Tax Assets	$ 1,096.8	$ 915.0
Deferred Tax Liabilities	(2,050.4)	(2,440.7)
Net Deferred Tax Liabilities	$ (953.6)	$ (1,525.7)
Property Related Temporary Differences	$ (403.0)	$ (579.2)
Amounts Due to (from) Customers for Future Federal Income Taxes	137.6	(50.4)
Deferred State Income Taxes	(180.5)	(158.8)
Deferred Income Taxes on Other Comprehensive Loss	(3.9)	8.7
Accrued Nuclear Decommissioning	(457.0)	(666.8)
Regulatory Assets	(43.8)	(81.0)
All Other, Net	(3.0)	1.8
Net Deferred Tax Liabilities	$ (953.6)	$ (1,525.7)

AEP System Tax Allocation Agreement

I&M joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The consolidated net operating loss of the AEP System is allocated to each company in the consolidated group with taxable losses. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the allocation of the consolidated AEP System net operating loss and the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

Federal and State Income Tax Audit Status

I&M and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2011. The IRS examination of years 2011, 2012 and 2013 started in April 2014. AEP and subsidiaries received a Revenue Agents Report in April 2016, completing the 2011 through 2013 audit cycle indicating an agreed upon audit. The 2011 through 2013 audit was submitted to the Congressional Joint Committee on Taxation for approval. The Joint Committee referred the audit back to the IRS exam team for further consideration. To resolve the issue under consideration, AEP and subsidiaries and the IRS exam team agreed to go to Appeals using Fast Track in December 2017. The issue was resolved with Appeals in March 2018 and now resides with the IRS exam team for further consideration. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, I&M accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

I&M and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns. I&M and other AEP subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. I&M is no longer subject to state or local income tax examinations by tax authorities for years before 2009.

Net Income Tax Operating Loss Carryforward

In 2017, I&M recognized federal net income tax operating losses of $333 million. The 2017 federal net income tax operating losses were driven primarily by bonus depreciation and deductions related to repair and maintenance costs associated with transmission and distribution property. Substantially all of the 2017 federal net income tax operating losses will be carried back to 2015. Management anticipates future taxable income will be sufficient to realize the remaining net income tax operating loss tax benefits before the federal carryforward expires after 2036.

I&M also has $14 million of West Virginia state income tax operating loss carryforwards as of December 31, 2017. Management anticipates future taxable income will be sufficient to realize the remaining net income tax operating loss tax benefits before the carryforward expires after 2037.

Tax Credit Carryforward

Federal and state net income tax operating losses sustained in 2017, 2012, 2011 and 2009 along with lower federal and state taxable income in 2010 resulted in unused federal and state income tax credits. As of December 31, 2017 and December 31, 2016, I&M had federal tax credit carryforwards of $11 million and $9 million, respectively. I&M anticipates future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused.

Uncertain Tax Positions

I&M recognizes interest accruals related to uncertain tax positions in interest income or expense as applicable, and Penalties in accordance with the accounting guidance for "Income Taxes."

The following table shows amounts reported for interest expense and interest income:

	Years Ended December 31, 2017	2016
	(in millions)	
Interest Expense	$ —	$ 0.2
Interest Income	1.0	—

The amounts accrued for payment of interest and penalties as of December 31, 2017 and 2016 were $1 million and $949 thousand, respectively.

The reconciliation of the beginning and ending amounts of unrecognized tax benefits are as follows:

	2017	2016
	(in millions)	
Balance as of January 1,	$ 3.8	$ 2.5
Increase – Tax Positions Taken During a Prior Period	0.2	1.7
Decrease – Tax Positions Taken During a Prior Period	(0.5)	(0.4)
Increase – Tax Positions Taken During the Current Year	—	—
Decrease – Tax Positions Taken During the Current Year	—	—
Increase – Settlements with Taxing Authorities	(0.3)	—
Decrease – Settlements with Taxing Authorities	—	—
Decrease – Lapse of the Applicable Statute of Limitations	—	—
Balance as of December 31,	$ 3.2	$ 3.8

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $2 million and $3 million for 2017 and 2016, respectively. Management believes that there will be no significant net increase or decrease in unrecognized benefits within 12 months of the reporting date.

Federal Tax Legislation

The Protecting Americans from Tax Hikes Act of 2015 (PATH) included an extension of the 50% bonus depreciation for three years through 2017, phasing down to 40% in 2018 and 30% in 2019. PATH also provided for the extension of research and development, employment and several energy tax credits for 2015. PATH also includes provisions to extend the wind energy production tax credit through 2016 with a three-year phase-out (2017-2019), and to extend the 30% temporary solar investment tax credit for three years through 2019 and with a two-year phase-out (2020-2021). PATH also provided for a permanent extension of the Research and Development tax credit. The enacted provisions did not materially impact I&M's net income or financial condition but did have a favorable impact on cash flows. The federal Tax Reform eliminated bonus depreciation for certain property acquired after September 27, 2017.

State Tax Legislation

Legislation was passed by the state of Indiana in May 2011 enacting a phased reduction in corporate income tax rate from 8.5% to 6.5%. The 8.5% Indiana corporate income tax rate will be reduced 0.5% each year beginning after June 30, 2012 with the final reduction occurring in years beginning after June 30, 2015. Additional legislation was passed by the state of Indiana reducing the corporate income tax rate from 6.5% to 4.9% beginning after June 30, 2016 with the final reduction occurring in years beginning after June 30, 2021. The legislation did not materially impact I&M's net income, cash flows or financial condition.

13. LEASES

Leases of property, plant and equipment are for remaining periods up to 14 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Operation Expenses and Maintenance Expenses in accordance with rate-making treatment for regulated operations. The components of rental costs are as follows:

	Years Ended December 31,	
	2017	**2016**
	(in millions)	
Net Lease Expense on Operating Leases	$ 88.4	$ 90.5
Amortization of Capital Leases	131.7	136.1
Interest on Capital Leases	7.0	6.3
Total Lease Rental Costs	$ 227.1	$ 232.9

The following table shows the property, plant and equipment under capital leases and related obligations recorded on I&M's balance sheets.

	December 31, 2017	December 31, 2016
	(in millions)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 27.2	$ 26.4
Other Property, Plant and Equipment	213.8	277.6
Total Property, Plant and Equipment	241.0	304.0
Accumulated Amortization	21.1	25.3
Net Property, Plant and Equipment Under Capital Leases	$ 219.9	$ 278.7
Obligations Under Capital Leases:		
Noncurrent	$ 120.6	$ 151.6
Current	99.3	127.1
Total Obligations Under Capital Leases	$ 219.9	$ 278.7

Future minimum lease payments consisted of the following as of December 31, 2017:

	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2018	$ 110.4	$ 91.3
2019	67.1	90.3
2020	31.5	86.9
2021	13.8	82.4
2022	6.8	81.4
Later Years	25.2	16.3
Total Future Minimum Lease Payments	254.8	$ 448.6
Less Estimated Interest Element	34.9	
Estimated Present Value of Future Minimum Lease Payments	$ 219.9	

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 either the unamortized balance or 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 unamortized balance. As of December 31, 2017, 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 is $3 million.

Rockport Lease

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant, Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it equally to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. AEP, AEGCo and I&M have no ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2017 are as follows:

	Future Minimum Lease Payments
	(in millions)
2018	$ 73.9
2019	73.9
2020	73.9
2021	73.9
2022	73.6
Total Future Minimum Lease Payments	$ 369.2

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as an operating lease. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M intends to renew the lease for the full lease term of twenty years via the renewal options. I&M's future minimum lease obligation is $7 million for the remaining railcars as of December 31, 2017. This obligation is included in the future minimum lease payments schedule earlier in this note.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from 83% of the projected fair value of the equipment under the current five-year lease term to 77% at the end of the 20-year term. I&M assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is $8 million as of December 31, 2017, assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, management believes that the fair value would produce a sufficient sales price to avoid any loss.

Nuclear Fuel Lease

In November 2011, I&M entered into a sale-and-leaseback transaction for $110 million with DCC Fuel IV LLC (DCC IV) to lease nuclear fuel for the Cook Plant. DCC IV 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 for $65 million and a fixed rate of 2.12% for $45 million. The lease is a capital lease with a term of 54 months. I&M makes payments on the lease quarterly in February, May, August and November. I&M made the final payment in April 2016.

In May 2013, I&M entered into a sale-and-leaseback transaction for $101 million with DCC Fuel VI LLC (DCC VI). DCC VI 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 capital lease with a term of 53 months. I&M makes payments on the lease quarterly in February, May, August and November. I&M made the final payment in October 2017.

In October 2014, I&M entered into a sale-and-leaseback transaction for $106 million with DCC Fuel VII LLC (DCC VII). DCC VII 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 capital lease with a term of 54 months. I&M makes payments on the lease quarterly in January, April, July and October. Payments began in January 2015.

In April 2015, I&M entered into a sale-and-leaseback transaction for $111 million with DCC Fuel VIII LLC (DCC VIII). DCC VIII 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 capital lease with a term of 54 months. I&M makes payments on the lease monthly. Payments began in May 2015.

In April 2016, I&M entered into a sale-and-leaseback transaction for $88 million with DCC Fuel IX LLC (DCC IX). DCC IX 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 capital lease with a term of 54 months. I&M makes payments on the lease quarterly in January, April, July and October. Payments began in July 2016.

In December 2016, I&M entered into a sale-and-leaseback transaction for $87 million with DCC Fuel X LLC (DCC X). DCC X 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 capital lease with a term of 52 months. I&M makes payments on the lease monthly. Payments began in January 2017.

In November 2017, I&M entered into a sale-and-leaseback transaction for $70 million with DCC Fuel XI LLC (DCC XI). DCC XI 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 capital lease with a term of 52 months. I&M makes payments on the lease monthly. Payments began in December 2017.

In November 2013, I&M entered into a sale-and-leaseback transaction with IMP 11-2013, a nonaffiliated Ohio trust, to lease nuclear fuel for I&M's Cook Plant. In November 2013, I&M sold a portion of its unamortized nuclear fuel inventory to the trust for $110 million. The lease has a variable rate based on one month LIBOR and is accounted for as a capital lease with lease terms up to 54 months. The future minimum lease payments for the sales-and-leaseback transaction as of December 31, 2017 are $2 million based on estimated fuel burn and will be paid in 2018.

14. FINANCING ACTIVITIES

Long-term Debt

The following table details long-term debt outstanding:

	Maturity	Weighted Average Interest Rate as of December 31, 2017	Interest Rate Ranges as of December 31, 2017	Interest Rate Ranges as of December 31, 2016	Outstanding as of December 31, 2017	Outstanding as of December 31, 2016
Senior Unsecured Notes	2019-2047	5.20%	3.20%-7.00%	3.20%-7.00%	$ 1,825.0	$ 1,525.0
Pollution Control Bonds (a)	2018-2025 (b)	2.02%	1.75%-2.75%	0.74%-4.625%	267.0	227.0
Spent Nuclear Fuel Obligation (c)					268.6	266.3
Other Long-term Debt	2018-2025	3.03%	2.82%-6.00%	2.15%-6.00%	214.4	215.9
Unamortized Discount, Net					(5.6)	(4.1)
Total Long-term Debt					$ 2,569.4	$ 2,230.1

(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. Consequently, these bonds have been classified for maturity purposes based on the mandatory redemption date.
(c) Spent nuclear fuel obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see "SNF Disposal" section of Note 6).

Long-term debt outstanding as of December 31, 2017 is payable as follows:

	(in millions)
2018	$ 378.4
2019	476.7
2020	1.8
2021	42.0
2022	2.2
After 2022	1,673.9
Principal Amount	2,575.0
Unamortized Discount, Net	(5.6)
Total Long-term Debt	$ 2,569.4

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 restriction that prohibits the payment of dividends out of capital accounts without regulatory approval; payment of dividends is allowed out of retained earnings only. Additionally, the Federal Power Act 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 also 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, 2017, 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 $1.4 billion.

The Federal Power Act restriction does not limit the ability of I&M to pay dividends out of retained earnings. However, the credit agreement covenant restrictions can limit the ability of I&M to pay dividends out of retained earnings. As of December 31, 2017, the amount of any such restrictions was $416 million. In February 2018, I&M distributed a $34 million dividend to Parent.

Corporate Borrowing Program – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of December 31, 2017 and 2016 are included in Notes Payable to Associated Companies on I&M's balance sheets. I&M's money pool activity and their 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)			
2017	$ 367.4	$ —	$ 204.9	$ —	$ 211.6	$ 500.0
2016	369.1	85.3	129.9	36.8	215.2	500.0

The maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

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 Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2017	1.85%	0.92%	—%	—%	1.27%	—%
2016	1.02%	0.69%	0.90%	0.72%	0.80%	0.76%

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 and interest income related to the corporate borrowing programs were immaterial for the years ended December 31, 2017 and 2016.

Securitized Accounts Receivables – AEP Credit

Under this sale of receivables arrangement, I&M sells, without recourse, certain of its customer accounts receivable and accrued unbilled 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. 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.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and expires in June 2019.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement as of December 31, 2017 and 2016 was $137 million and $137 million, respectively.

The fees paid to AEP Credit for customer accounts receivable sold were $7 million and $7 million for the years ended December 31, 2017 and 2016, respectively.

I&M's proceeds on the sale of receivables to AEP Credit were $1.6 billion and $1.6 billion for the years ended December 31, 2017 and 2016, respectively.

15. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "AEP System Tax Allocation Agreement" section of Note 12 in addition to "Corporate Borrowing Program – AEP System" and "Securitized Accounts Receivables – AEP Credit" sections of Note 14.

Power Coordination Agreement (PCA) and Bridge Agreement

Effective January 1, 2014, the FERC approved the following agreements.

- A PCA among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Effective May 2015, the PCA was revised and approved by the FERC to include WPCo. Under the PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. Further, the Restated and Amended 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.
- A Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies would fulfill their existing obligations under the PJM Reliability Assurance Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR committed to use its capacity to help meet the PJM capacity obligations of member companies through the PJM planning year that ended May 31, 2015.

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. Effective January 1, 2014 and revised in May 2015, 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, while power and natural gas risk management activities for PSO and SWEPCo are allocated based on the Operating Agreement.

System Integration Agreement (SIA)

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity. Margins resulting from trading and marketing activities originating in PJM and MISO generally accrue to the benefit of APCo, I&M, KPCo and WPCo, while trading and marketing activities originating in SPP generally accrue to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the equity positions of these companies.

Affiliated Revenues and Purchases

The following table shows the revenues derived from direct sales to affiliates, auction sales to affiliates, net transmission agreement sales and other revenues:

Related Party Revenues	Years Ended December 31, 2017	2016
	(in millions)	
Direct Sales to West Affiliates	$ 3.8	$ —
Auction Sales to OPCo (a)	—	12.0
Transmission Agreement	(4.4)	12.2
Other Revenues	2.4	2.0

(a) Refer to the Ohio Auction section below for further information regarding these amounts.

The following table shows the purchased power expenses incurred for purchases from affiliates:

Related Party Purchases	Years Ended December 31, 2017	2016
	(in millions)	
Direct Purchases from AEGCo	$ 223.9	$ 228.6

Transmission Agreement (TA)

APCo, I&M, KGPCo, KPCo, OPCo and WPCo (AEP East Companies) are parties to the TA, effective November 2010, which defines how transmission costs through PJM OATT are allocated among the AEP East Companies on a 12-month average coincident peak basis. I&M's net charges for the years ended December 31, 2017 and 2016 related to the TA were $104 million and $53 million, respectively. The charges were recorded in Operation Expenses on the statements of income.

Ohio Auctions

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015. AEP Energy, AEPEP, APCo, KPCo, I&M and WPCo participate in the auction process and have been awarded tranches of OPCo's SSO load. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions.

Unit Power Agreements (UPA)

UPA between AEGCo and I&M

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. Subsequently, I&M assigns 30% of the power to KPCo. See the “UPA between AEGCo and KPCo” section below. 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 its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

UPA between AEGCo and KPCo

Pursuant to an assignment between I&M and KPCo and a UPA between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo pays to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo UPA ends in December 2022.

Cook Coal Terminal

Cook Coal Terminal, which is owned by AEGCo, performs coal transloading and storage services at cost for I&M. I&M recorded costs from AEGCo of $10.2 million and $12.8 million for transloading services in Fuel Stock on the balance sheets for the years ended December 31, 2017 and 2016, respectively.

Cook Coal Terminal also performs railcar maintenance services at cost for I&M. AEGCo billed I&M $1 million and $2 million for the years ended December 31, 2017 and 2016, respectively, for railcar maintenance services. I&M recorded the cost of the railcar maintenance services in Fuel Stock on the balance sheets.

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 NO_X emissions at certain generation plants in the AEP System. I&M recorded revenues from barging, transloading and other services of $63 million and $62 million for the years ended December 31, 2017 and 2016, respectively, in Revenues from Nonutility Operations on the statements of income.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers the cost of performing these services on the balance sheet and then transfers the cost to the affiliate for reimbursement. I&M recorded billings from APCo of $3 million and $3 million as capital or maintenance expenses depending on the nature of the services received for the years ended December 31, 2017 and 2016, respectively. These billings are recoverable from customers.

OVEC

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2017, the ownership and investment in OVEC were as follows:

	December 31, 2017	
Company	**Ownership**	**Investment**
		(in millions)
Parent	39.17%	$ 4.0
OPCo	4.30%	0.4
Total	43.47%	$ 4.4

OVEC's owners, along with APCo and I&M, are members to an intercompany power agreement. Participants of this agreement are entitled to receive and obligated to pay for all OVEC generating capacity, approximately 2,400 MWs, in proportion to their respective power participation ratios. The aggregate power participation ratio of certain AEP utility subsidiaries, including APCo, I&M and OPCo, is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs, including outstanding indebtedness, and provide a return on capital. The intercompany power agreement ends in June 2040.

AEP and other nonaffiliated owners authorized environmental investments related to their ownership interests. OVEC financed capital expenditures in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at its two generation plants. These environmental projects were funded through debt issuances. As of December 31, 2017, OVEC's outstanding indebtedness is approximately $1.4 billion. AEP utility subsidiaries are responsible for their 43.47% share of OVEC's outstanding debt. Principal and interest payments related to OVEC's outstanding indebtedness are disclosed in accordance with the accounting guidance for "Commitments." See the "Commitments" section of Note 6.

Purchased Power from OVEC

I&M paid $51 million and $44 million for power purchased from OVEC for the years ended December 31, 2017 and 2016, respectively. The amounts shown above are recoverable from customers and are included in Operation Expenses on the statements of income.

Sales and Purchases of Property

I&M had affiliated sales and purchases of electric property 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. The following table shows the sales and purchases, recorded at net book value.

	Years Ended December 31, 2017	2016
	(in millions)	
Sales	$ 5.0	$ 5.2
Purchases	3.5	2.7

The amounts above are recorded in Utility Plant on the balance sheets.

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.

AEPSC

AEPSC provides certain managerial and professional services to AEP's subsidiaries. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEPSC and its billings are subject to regulation by the FERC. I&M's total billings from AEPSC were $176 million and $148 million for the years ended December 31, 2017 and 2016, respectively.

16. 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)			
2017	1.9	3.8	5.3	2.7	1.7	2.7	8.4
2016	1.9	3.9	2.4	2.7	1.7	2.8	8.6

The composite depreciation rate generally includes a component for non-asset retirement obligation (non-ARO) removal costs, which is credited to accumulated depreciation. Actual removal costs incurred are charged to accumulated depreciation.

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 and for the retirement of certain ash disposal facilities. I&M also records ARO for the decommissioning of the Cook Plant. 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.

As of December 31, 2017 and 2016, I&M's ARO liability for nuclear decommissioning of the Cook Plant was $1.30 billion and $1.24 billion, respectively. These liabilities are reflected in Asset Retirement Obligations on I&M's balance sheets. As of December 31, 2017 and 2016, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $2.22 billion and $1.95 billion, respectively. The following is a reconciliation of the 2017 and 2016 aggregate carrying amounts of ARO:

Year	ARO at January 1,	Accretion Expense	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31,
			(in millions)		
2017	$ 1,258.1	$ 55.9	$ (0.1)	$ 7.9	$ 1,321.8
2016	1,253.8	55.6	(62.6)	11.3	1,258.1

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:

			Share as of December 31, 2017		
Facility	**Fuel Type**	**Percent of Ownership**	**Utility Plant in Service**	**Construction Work in Progress**	**Accumulated Depreciation**
				(in millions)	
Rockport Generating Plant (a)(b)(c)	Coal	50.0%	$ 1,093.9	$ 28.2	$ 562.6

			Share as of December 31, 2016		
Facility	**Fuel Type**	**Percent of Ownership**	**Utility Plant in Service**	**Construction Work in Progress**	**Accumulated Depreciation**
				(in millions)	
Rockport Generating Plant (a)(b)(c)	Coal	50.0%	$ 936.1	$ 125.8	$ 535.1

(a) Operated by I&M.
(b) Amounts include I&M's 50% ownership of both Unit 1 and capital additions for Unit 2. Unit 2 is subject to an operating lease with a non-affiliated company. See the "Rockport Lease" section of Note 13.
(c) AEGCo owns 50% of Unit 1 with I&M and 50% of capital additions for Unit 2.

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, 2017 and 2016, 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)			
Year Ended December 31, 2017								
East Busco Station	Distribution	Churubusco, IN	363	$ 5.6	562	$ -	592	$ -
Year Ended December 31, 2016								
East Busco Station	Distribution	Churubusco, IN	363	$ 5.5	562	$ -	592	$ -

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)
1	Balance of Account 219 at Beginning of Preceding Year				(3,421,107)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				31,958
3	Preceding Quarter/Year to Date Changes in Fair Value				(867,589)
4	Total (lines 2 and 3)				(835,631)
5	Balance of Account 219 at End of Preceding Quarter/Year				(4,256,738)
6	Balance of Account 219 at Beginning of Current Year				(4,256,738)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				68,917
8	Current Quarter/Year to Date Changes in Fair Value				2,745,882
9	Total (lines 7 and 8)				2,814,799
10	Balance of Account 219 at End of Current Quarter/Year				(1,441,939)

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

Line No.	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 117, Line 78) (i)	Total Comprehensive Income (j)
1	(13,318,124)		(16,739,231)		
2	1,318,349		1,350,307		
3			(867,589)		
4	1,318,349		482,718	239,855,788	240,338,506
5	(11,999,775)		(16,256,513)		
6	(11,999,775)		(16,256,513)		
7	1,318,349		1,387,266		
8			2,745,882		
9	1,318,349		4,133,148	186,742,763	190,875,911
10	(10,681,426)		(12,123,365)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	7,527,470,350	7,527,470,350
4	Property Under Capital Leases	39,723,351	39,723,351
5	Plant Purchased or Sold		
6	Completed Construction not Classified	764,257,954	764,257,954
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	8,331,451,655	8,331,451,655
9	Leased to Others		
10	Held for Future Use	1,444,928	1,444,928
11	Construction Work in Progress	460,208,619	460,208,619
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	8,793,105,202	8,793,105,202
14	Accum Prov for Depr, Amort, & Depl	2,948,719,776	2,948,719,776
15	Net Utility Plant (13 less 14)	5,844,385,426	5,844,385,426
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,824,609,776	2,824,609,776
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	124,105,455	124,105,455
22	Total In Service (18 thru 21)	2,948,715,231	2,948,715,231
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	4,545	4,545
29	Amortization		
30	Total Held for Future Use (28 & 29)	4,545	4,545
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,948,719,776	2,948,719,776

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
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					10
					11
					12
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					32
					33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials	-3,580,638	105,033,208
4	Allowance for Funds Used during Construction	3,580,638	2,350,909
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)	1,493,621	70,235,508
10	SUBTOTAL (Total 8 & 9)	1,493,621	
11	Spent Nuclear Fuel (120.4)	684,727,053	102,030,937
12	Nuclear Fuel Under Capital Leases (120.6)	239,146,482	69,500,000
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	685,160,271	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	240,206,885	
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)		

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
	68,057,580	33,394,990	3
	1,879,178	4,052,369	4
			5
		37,447,359	6
			7
			8
	70,381,840	1,347,289	9
		1,347,289	10
	91,316,389	695,441,601	11
128,617,652		180,028,830	12
-101,817,639	91,316,389	695,661,521	13
		218,603,558	14
			15
			16
			17
			18
			19
			20
			21
			22

Schedule Page: 202 Line No.: 3 Column: e

Placed nuclear fuel into reactor

Schedule Page: 202 Line No.: 4 Column: e

Placed nuclear fuel into reactor

Schedule Page: 202 Line No.: 9 Column: e

Nuclear fuel removed from reactor and placed into spent fuel pool - $881,840

Reclassification of nuclear fuel from owned to leased due to sale/leaseback with third party - $69,500,000

Schedule Page: 202 Line No.: 11 Column: e

Retirement of spent fuel

Schedule Page: 202 Line No.: 12 Column: b

Includes 2016 costs in connection with nuclear leases:
Finance charges - $2,864,054

Schedule Page: 202 Line No.: 12 Column: c

Reclassification of $69,500,000 of nuclear fuel from owned to leased due to sale/leaseback with third party

Schedule Page: 202 Line No.: 12 Column: f

Includes 2017 costs in connection with nuclear leases:
Finance charges - $3,822,473

Schedule Page: 202 Line No.: 13 Column: e

Retirement of nuclear fuel

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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 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)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	117,426	
3	(302) Franchises and Consents	19,866,098	
4	(303) Miscellaneous Intangible Plant	86,400,196	65,047,300
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	106,383,720	65,047,300
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	7,383,217	31,288
9	(311) Structures and Improvements	104,567,799	3,659,000
10	(312) Boiler Plant Equipment	626,040,695	146,930,329
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	107,937,992	4,785,209
13	(315) Accessory Electric Equipment	62,680,573	103,474
14	(316) Misc. Power Plant Equipment	22,552,625	852,562
15	(317) Asset Retirement Costs for Steam Production	5,654,572	7,917,245
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	936,817,473	164,279,107
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	1,879,588	
19	(321) Structures and Improvements	405,596,652	27,317,015
20	(322) Reactor Plant Equipment	1,485,818,186	33,251,680
21	(323) Turbogenerator Units	496,146,650	218,282,052
22	(324) Accessory Electric Equipment	244,943,814	15,573,858
23	(325) Misc. Power Plant Equipment	229,168,774	29,700,670
24	(326) Asset Retirement Costs for Nuclear Production	135,680,600	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	2,999,234,264	324,125,275
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	706,302	
28	(331) Structures and Improvements	3,755,493	42,759
29	(332) Reservoirs, Dams, and Waterways	22,181,936	95,621
30	(333) Water Wheels, Turbines, and Generators	16,401,132	16,998
31	(334) Accessory Electric Equipment	5,326,038	171,113
32	(335) Misc. Power PLant Equipment	2,569,893	75,190
33	(336) Roads, Railroads, and Bridges	853	
34	(337) Asset Retirement Costs for Hydraulic Production	318,520	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	51,260,167	401,681
36	D. Other Production Plant		
37	(340) Land and Land Rights	181,743	
38	(341) Structures and Improvements	734,271	848
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators	35,346,662	33,962
42	(345) Accessory Electric Equipment	269,039	23
43	(346) Misc. Power Plant Equipment	555,930	796
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	37,087,645	35,629
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,024,399,549	488,841,692

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	69,671,987	949,248
49	(352) Structures and Improvements	24,008,047	3,474,555
50	(353) Station Equipment	713,528,933	43,779,515
51	(354) Towers and Fixtures	233,328,402	694,857
52	(355) Poles and Fixtures	163,079,387	16,736,880
53	(356) Overhead Conductors and Devices	260,285,940	7,675,960
54	(357) Underground Conduit	2,312,344	
55	(358) Underground Conductors and Devices	6,010,547	229,673
56	(359) Roads and Trails	347,293	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,472,572,880	73,540,688
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	21,358,506	480,097
61	(361) Structures and Improvements	14,811,177	9,857,182
62	(362) Station Equipment	244,926,449	60,225,873
63	(363) Storage Battery Equipment	5,488,901	119,370
64	(364) Poles, Towers, and Fixtures	259,353,877	16,090,534
65	(365) Overhead Conductors and Devices	416,967,574	31,478,391
66	(366) Underground Conduit	86,716,317	16,498,616
67	(367) Underground Conductors and Devices	228,330,495	21,566,314
68	(368) Line Transformers	306,878,570	18,624,683
69	(369) Services	172,328,184	7,509,810
70	(370) Meters	95,057,448	2,993,311
71	(371) Installations on Customer Premises	26,350,181	1,232,643
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	20,562,372	886,672
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,899,130,051	187,563,496
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	2,961,449	
87	(390) Structures and Improvements	50,338,036	2,337,564
88	(391) Office Furniture and Equipment	6,993,749	89,226
89	(392) Transportation Equipment		
90	(393) Stores Equipment	131,918	602,378
91	(394) Tools, Shop and Garage Equipment	13,215,370	2,131,024
92	(395) Laboratory Equipment	395,859	
93	(396) Power Operated Equipment	543,715	
94	(397) Communication Equipment	43,656,908	3,067,152
95	(398) Miscellaneous Equipment	10,197,450	188,907
96	SUBTOTAL (Enter Total of lines 86 thru 95)	128,434,454	8,416,251
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	172,921	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	128,607,375	8,416,251
100	TOTAL (Accounts 101 and 106)	7,631,093,575	823,409,427
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)	7,631,093,575	823,409,427

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			117,426		2
			19,866,098		3
4,503,458		-132,953	146,811,085		4
4,503,458		-132,953	166,794,609		5
					6
					7
			7,414,505		8
872,969			107,353,830		9
3,888,833			769,082,191		10
					11
1,620,501			111,102,700		12
16,002			62,768,045		13
49,038			23,356,149		14
			13,571,817		15
6,447,343			1,094,649,237		16
					17
			1,879,588		18
6,424,376		956	426,490,247		19
13,452,840		-956	1,505,616,070		20
61,963,123			652,465,579		21
3,170,192			257,347,480		22
4,032,261		132,952	254,970,135		23
			135,680,600		24
89,042,792		132,952	3,234,449,699		25
					26
			706,302		27
			3,798,252		28
54,199			22,223,358		29
11,269			16,406,861		30
85,673			5,411,478		31
3,428			2,641,655		32
			853		33
			318,520		34
154,569			51,507,279		35
					36
			181,743		37
			735,119		38
					39
					40
			35,380,624		41
			269,062		42
			556,726		43
					44
			37,123,274		45
95,644,704		132,952	4,417,729,489		46

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
		-210,970	70,410,265		48
529,945		-10,028	26,942,629		49
31,214,489		-4,023,751	722,070,208		50
743,086			233,280,173		51
3,339,518			176,476,749		52
2,332,865			265,629,035		53
			2,312,344		54
39,177			6,201,043		55
			347,293		56
					57
38,199,080		-4,244,749	1,503,669,739		58
					59
		-233,665	21,604,938		60
43,159		10,028	24,635,228		61
3,230,753		4,027,547	305,949,116		62
			5,608,271		63
2,757,803		-3,795	272,682,813		64
3,404,218			445,041,747		65
68,090		310,681	103,457,524		66
1,569,216		-433,611	247,893,982		67
6,649,991		122,930	318,976,192		68
1,328,922			178,509,072		69
1,418,093			96,632,666		70
517,096			27,065,728		71
					72
442,465			21,006,579		73
					74
21,429,806		3,800,115	2,069,063,856		75
					76
					77
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					80
					81
					82
					83
					84
					85
		227,064	3,188,513		86
945,054			51,730,546		87
7,414			7,075,561		88
					89
			734,296		90
648,598			14,697,796		91
28,673			367,186		92
			543,715		93
1,067,218			45,656,842		94
83,122			10,303,235		95
2,780,079		227,064	134,297,690		96
					97
			172,921		98
2,780,079		227,064	134,470,611		99
162,557,127		-217,571	8,291,728,304		100
					101
					102
					103
162,557,127		-217,571	8,291,728,304		104

Schedule Page: 204 Line No.: 49 Column: g

The investment and related accumulated depreciation in Generation Step-Up Units (GSU's) in plant accounts 352-353 included in I&M's generation formula rates are identified by a query of the plant accounting system.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
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41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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				
3	Rockport Generating Plant Unit 1 (0111)	11/01/84		1,034,109
4				
5				
6				
7				
8				
9				
10				
11				
12	Items under $250,000			404,896
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23	Items Under $250,000			5,923
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
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46				
47	Total			1,444,928

Schedule Page: 214 Line No.: 46 Column: d

The generation assets in Electric Plant Held for Future use included in I&M's generation formula rates are identified by a query of the plant accounting system.

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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	Spy Run Building Replacement	7,868,423
2	South Bend, IN Land Purchase	5,126,259
3	IM/IN/Network Assess/Rehab	4,817,772
4	IM/IN NETWORK PRIMARY REHAB FW	1,115,225
5	IM/IN NETWORK PRIMARY REHAB SB	2,028,664
6	IM/IN NETWROK PRIMARY REHAB MU	2,123,734
7	IMPCo Distr Pre Eng Parent	2,569,708
8	IM/IN/Webster Sta Purchase	1,635,789
9	IM/IN/Network Monitor Design	12,775,463
10	IM/IN/Water Pollution Upgrades	1,393,686
11	IM/MI Wheeler D station	1,838,343
12	Montpelier D Station Rebuild	2,841,156
13	EKH SPILLWAY GATE REPLACEMENT	2,365,174
14	Innovari Pilot Distribution	2,510,299
15	IM/IN/Volt/VAR Opt Dist Line	3,850,359
16	Maximo Imp - IM - G	1,387,172
17	Maximo Imp - IM - D	1,286,356
18	Maximo Imp - IM - Nuc	2,272,950
19	U1 Steam Generator WL Controls	11,707,147
20	U2 SG Water Level Controls	14,169,781
21	Unit 2 Refueling Equip Rpl	1,038,908
22	U2 RPS ESFAS	11,297,425
23	U1 RPS ESFAS	11,811,773
24	U2 Feedwater Htrs HP	14,280,346
25	U1 MSR FW Htr Drains Digital	1,907,656
26	U2 RMS System	12,034,828
27	U1 RMS System	13,437,432
28	U2 Reactor Cavity Lift System	1,575,181
29	U2 HDP Discharge Valves Rplmnt	9,539,409
30	U2 MSR FW Heater Digital Cnt	4,407,011
31	U2 RVI Aging Mgmt Inspections	4,887,828
32	U1 Blowdown Recovery CPI	11,411,944
33	Unit 1 Spec 200	9,269,195
34	Unit 2 Spec 200	9,002,389
35	U1 Reactor Cntls & Inst Upgrd	8,410,277
36	U2 Reactor Cntls & Inst Upgrd	10,286,827
37	U2 DCS Control Room Computers	2,625,404
38	U1 Hold Down Spring	1,066,190
39	Unit 2 Hold Down Spring	1,065,965
40	Purchase/Install FCUs	1,328,638
41	Purchase/Install FCUs	1,779,934
42	U2 Main Gen Rotor Rplmnt	5,633,281
43	TOTAL	460,208,619

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	U2 Baffle-Former Bolt Rplcmnt	21,371,814
2	Fukishima - Flood Hazards Eval	5,603,017
3	U1 Baffle-Former Bolt Rplcmnt	4,220,614
4	RKP05CIIM Horiz RH ReplaceU1	2,966,424
5	RK15CIU1 LP TurbRtr and BldCar	10,803,743
6	RK I&M U2 SCR	11,740,318
7	T/IM/Transmission Line Rebuild	2,340,310
8	D/I&M/Purchase/Rebuild Maj Eqp	2,415,986
9	Transmission Asset Health/IN,M	1,988,406
10	T/IM/Telecom Upgrades	1,549,794
11	D/IM/Telecom Upgrades-IN	1,426,028
12	NERC Physical Security - IM	3,306,140
13	T/IM/TranscoAssetRenewl&Refurb	6,476,629
14	D/IM/TranscoAssetRenewl&Refurb	1,193,595
15	Trans station Renew-Refurb I&M	20,038,343
16	Trans Line Renew-RefurbI&M	1,408,764
17	Dist Station Renew-Refu I&M IN	1,575,741
18	I&M IN Major Eq/Spare -Trans	2,544,512
19	I&M IN Major Eq/Spares- Distr	7,683,104
20	T/IM/Capital Blanket - IMPCo	3,195,248
21	D/IM/Capital Blanket - IMPCo	1,990,517
22	T/IMPC/FWCityImprovements	11,429,947
23	D/IM/Distribution Work	7,021,305
24	T/IM/Transmisison Work	1,856,278
25	I&M Distribution Work	1,357,005
26	I&M Transmission Work	1,874,460
27	T/IM/Transmission Work	2,818,376
28	T/IM/Transmission Work	1,918,226
29	T/IM/Transmission Work	2,467,270
30	D/IM/Distribution Work	6,917,592
31	D/IM/Distribution Work	1,989,785
32	T/IM/Transmission Work	1,572,258
33	T/IM/Transmission Work	1,057,474
34	D/IM/IM D void	1,835,226
35	IMPCo Distribution Work	2,532,862
36	I&M Transmission Work	3,187,974
37	IMPCo Trans Pre Eng Parent	2,855,985
38	IMPCo Trans Pre Eng Parent	2,953,125
39	WS-CI-IMPCo-G PPB	3,642,090
40	RP-CI-IMPCo-G NMIB	5,138,642
41	Ed-Ci-Impco-D Ast Imp	4,259,581
42	Ed-Ci-Impco-D Cust Serv	1,512,009
43	TOTAL	460,208,619

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	IMPCO-D Telecom	1,079,851
2	Other Minor Projects under $1,000,000	39,310,950
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42		
43	TOTAL	460,208,619

Schedule Page: 216 Line No.: 1 Column: b

The generation assets in Construction Work in Progress included in I&M's generation formula rates are identified by a query of the plant accounting system.

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

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 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), 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.

Section A. Balances and Changes During Year

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)
1	Balance Beginning of Year	2,853,531,804	2,853,527,336	4,468	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	179,684,686	179,684,609	77	
4	(403.1) Depreciation Expense for Asset Retirement Costs	1,723,493	1,723,493		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	4,272,105	4,272,105		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	185,680,284	185,680,207	77	
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	157,793,791	157,793,791		
13	Cost of Removal	62,230,995	62,230,995		
14	Salvage (Credit)	6,076,887	6,076,887		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	213,947,899	213,947,899		
16	Other Debit or Cr. Items (Describe, details in footnote):	-649,868	-649,868		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,824,614,321	2,824,609,776	4,545	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	250,518,670	250,518,670		
21	Nuclear Production	1,386,163,641	1,386,163,641		
22	Hydraulic Production-Conventional	30,906,706	30,906,706		
23	Hydraulic Production-Pumped Storage				
24	Other Production	2,494,026	2,494,026		
25	Transmission	515,738,257	515,733,712	4,545	
26	Distribution	608,012,876	608,012,876		
27	Regional Transmission and Market Operation				
28	General	30,780,145	30,780,145		
29	TOTAL (Enter Total of lines 20 thru 28)	2,824,614,321	2,824,609,776	4,545	

Schedule Page: 219 Line No.: 8 Column: c

Amortize Indiana jurisdictional portion of regulatory asset for Ash Pond ARO's per IURC Order in Cause No. 43306	$ -6,677
Indiana jurisdictional share of depreciation expense for Rockport DSI for Cause No. 44331	1,451,167
Indiana LCM rider to record over/under recovery of depreciation per Cause No. 44182 LCM 1	3,322,246
Amortize Indiana jurisdictional portion of LCM deferred balances per IURC Cause No. 44182 LCM 1	-755,498
DSI over/under for Federal Mandate Rider effective Jan 2015 per IURC Order in Cause 44331	204,945
Michigan deferred depreciation expense for EECO per MPSC Order in Case No. U-17353	32,586
Michigan jurisdictional share of deferred depreciation expense for Cook Plant LCM 1 per Case No. U-17026	1,057,189
MI Def Clean Energy Solar Pilot Project	-795,605
Amortize net over recovery DSI costs	-293,022
IN Def Clean Energy Solar Pilot Project per Indiana Order Cause No. 44511	703,116
SCR over/under for Clean Coal Technology Rider effective Jul 2016 per IURC Order in Cause 44523	-999,133
ARO depreciation expense in account 1080013	350,791
Total	$4,272,105

Schedule Page: 219 Line No.: 13 Column: c

Includes $17,595,632 of removal cost in retirement work in progress (RWIP).

Schedule Page: 219 Line No.: 14 Column: c

Includes ($2,468,873) of salvage charges in retirement work in progress (RWIP).

Schedule Page: 219 Line No.: 16 Column: c

ARO Reserve in account 1080013	$-1,072,028
Record gain on sale of Tanners Creek Plant land and closure of ARO liabilities	-923
Transfer between Accounts	423,083
Total	$ -649,868

Schedule Page: 219 Line No.: 21 Column: b

The portion of ARO related accumulated depreciation excluded from the ratebase in I&M's generation formula rates is identified by a query of the plant accounting system.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under 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.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Blackhawk Coal Company, Inc.	09-01-80		
2	Common Stock			25,324,000
3	Cash Capital Contribution			
4	Equity in Earnings			-6,674,314
5	Investment in Subsidiary AOCI			
6	Subtotal			18,649,686
7				
8	Price River Coal Company, Inc.	12-01-65		
9	Common Stock			27,275
10	Subtotal			27,275
11				
12				
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42	Total Cost of Account 123.1 $ 0		TOTAL	18,676,961

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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 form investments, including such revenues form 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 difference 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

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)	Line No.
				1
		25,324,000		2
				3
384,898		-6,289,416		4
				5
384,898		19,034,584		6
				7
				8
		27,275		9
		27,275		10
				11
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384,898		19,061,859		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)	31,333,494	30,732,935	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	922,321	621,540	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	68,270,908	86,985,787	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	77,035,451	68,447,753	Electric
8	Transmission Plant (Estimated)	913,624	540,017	Electric
9	Distribution Plant (Estimated)	725,790	686,357	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	248,184	285,085	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	147,193,957	156,944,999	Electric
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	2,093,490	2,112,441	River Transport
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	181,543,262	190,411,915	

Schedule Page: 227 Line No.: 11 Column: b

Assigned to - Other includes Customer Account, Administrative and General Expenses.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2018 No. (d)	2018 Amt. (e)
1	Balance-Beginning of Year	413,789.00	30,011,063	108,293.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	1,507.00			
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	35,256.00	1,529,238		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27	Consent Decree Surrenders	-2.00		51,254.00	
28	Total	-2.00		51,254.00	
29	Balance-End of Year	380,042.00	28,481,825	57,039.00	
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	357.00		357.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	357.00			
40	Balance-End of Year			357.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		74		
45	Gains		74		
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 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 acquire 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 an 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.

2019		2020		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
80,899.00		80,899.00		2,107,172.00		2,791,052.00	30,011,063	1
								2
								3
				81,376.00		82,883.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						35,256.00	1,529,238	18
								19
								20
								21
								22
								23
								24
								25
								26
						51,252.00		27
						51,252.00		28
80,899.00		80,899.00		2,188,548.00		2,787,427.00	28,481,825	29
								30
								31
								32
								33
								34
								35
357.00		357.00		56,199.00		57,627.00		36
				714.00		714.00		37
								38
				357.00		714.00		39
357.00		357.00		56,556.00		57,627.00		40
								41
								42
								43
					17		91	44
					17		91	45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2018 No. (d)	2018 Amt. (e)
1	Balance-Beginning of Year	22,417.00		18,365.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	3,270.00		3,785.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Allegheny Energy Supply	600.00	367,800		
10					
11					
12					
13					
14					
15	Total	600.00	367,800		
16					
17	Relinquished During Year:				
18	Charges to Account 509	13,905.00	198,676		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Northeast Texas Elec Coop	63.00			
23					
24					
25					
26					
27					
28	Total	63.00			
29	Balance-End of Year	12,319.00	169,124	22,150.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)		315		
34	Gains		315		
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				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 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 acquire 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 an 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.

2019		2020		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						40,782.00		1
								2
								3
						7,055.00		4
								5
								6
								7
								8
						600.00	367,800	9
								10
								11
								12
								13
								14
						600.00	367,800	15
								16
								17
						13,905.00	198,676	18
								19
								20
								21
						63.00		22
								23
								24
								25
								26
								27
						63.00		28
						34,469.00	169,124	29
								30
								31
								32
							315	33
							315	34
								35
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								46

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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 Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
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17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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 Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
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46						
47						
48						
49	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	PJM #AC1-072	139	186		
3	PJM #AA2-106	617	186	617	186
4	PJM #AA2-148	164	186	165	186
5	PJM #AB1-006	572	186	409	186
6	PJM #AB1-080	520	186		
7	PJM #AB1-087	619	186	774	186
8	PJM #AB1-088	531	186	530	186
9	PJM #AB2-028	1,204	186	1,203	186
10	PJM #AB2-065	1,537	186	1,537	186
11	PJM #AC1-040	1,421	186	1,421	186
12	PJM #AC1-059	664	186	547	186
13	PJM #AC1-072	94	186	94	186
14	PJM #AC1-141	402	186	704	186
15	PJM #AC1-148	139	186		
16	PJM #AC1-152	1,039	186	808	186
17	PJM #AC1-172	870	186	639	186
18	PJM #AC1-174	881	186	840	186
19	PJM #AC1-175	881	186	840	186
20	PJM #AC1-225	1,512	186	1,507	186
21	**Generation Studies**				
22	Rockport Generation Int. Study	1,000	500		
23	Twin Branch Solar Gen Int. Study	3,124	107		
24	South Bend Solar Gen Int. Study	46,000	183	10,074	183
25	Cook Unit 2 Generation Int. Study	72,333	107		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

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	PJM #AC2-080	6,277	186	57	186
3	PJM #AD1-043	272	186	190	186
4	PJM #AD1-128	2,089	186	1,972	186
5	PJM #V3-007	138	186		
6					
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20					
21	**Generation Studies**				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	SFAS 112 Post Employment Benefits	11,424,980	56,893	228	1,759,117	9,722,756
2						
3	Cook Plant Refueling Levelization	75,203,154	68,670,602	Various	77,212,263	66,661,493
4						
5	Unamortized Loss on Reacquired Debt	1,241,719		428	206,953	1,034,766
6	Amort 1/1995 - 12/2022					
7						
8	Unrealized Loss on Forward Commitments	(5,778,772)	12,186,412	Various	4,354,601	2,053,039
9						
10	Netting of Trading Activities Related to Unrealized	5,909,692	3,958,736	Various	4,431,190	5,437,238
11	Gains/Losses on Forward Commitments Between					
12	Regulated Assets/Liabilities					
13						
14	Asset Retirement Obligations	360,685		411,403	111,812	248,873
15	Amortz 3/2009 - 3/2020					
16	Per IURC Cause Order #43306					
17						
18	Indiana Rate Case expenses	600,384	486,305			1,086,689
19	Per IURC Cause Order #44075					
20						
21	Michigan Rate Case Expenses	63,524	476,748			540,272
22						
23	Deferred RTO Equity Carrying Charges	(146,412)	48,804			-97,608
24	Amort 1/2005 - 12/2019					
25						
26	BridgeCo Transmission Org Funding	419,499		407	129,174	290,325
27	Amort 1/2005 - 12/2019					
28	FERC Docket No. AC04-101-000					
29						
30	Other PJM Integration	390,446		407	120,228	270,218
31	Amort 1/2005 - 12/2019					
32	FERC Docket No. AC04-101-000					
33						
34	Carrying Charges - RTO Startup Costs	269,315		407	82,928	186,387
35	Amort 1/2005 - 12/2019					
36	FERC Docket No. AC04-101-000 and EL05-74-000					
37						
38	Alliance RTO Deferred Expense	240,913		407	74,183	166,730
39	Amort 1/2005 - 12/2019					
40	FERC Docket No. AC04-101-000					
41						
42						
43						
44	TOTAL	703,726,641	356,257,048		455,572,319	604,411,370

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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 the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	SFAS 158 Employer Accounting for Defined	141,903,128	8,610,037	Various	72,711,174	77,801,991
2	Benefit Pension & Other Postretirement Plans					
3						
4	DSM Energy Optimization Program - Michigan	1,071,257	2,435,638	Various	1,986,543	1,520,352
5	Under-recovered costs					
6						
7	OSS Margin Sharing	24,316,713		447	15,360,543	8,956,170
8						
9	SFAS 109 Deferred FIT	167,435,890	101,102,289	Various	185,012,009	83,526,170
10						
11	SFAS 109 Deferred SIT	158,511,941	26,313,589	283	4,470,789	180,354,741
12						
13	City of Fort Wayne Settlement	7,638,646		588	914,590	6,724,056
14	Amortization 3/13 - 4/25					
15	Per IURC Cause Order #44075					
16						
17	Cook Turbine Replacement - Michigan	4,312,810	1,190,288	421	282,161	5,220,937
18	Per MPSC Case U-16801					
19						
20	Cook Turbine Replacement CC _Indiana	8,441,783	3,395,849	421	1,193,644	10,643,988
21	Per IURC Cause Order #44075					
22						
23	Cook Unit 2 Baffle Bolts	6,348,650		530	299,936	6,048,714
24	Amort 3/2013 - 2/2038					
25	Per IURC Cause Order #44075					
26						
27	Capacity Settlement - IN Portion	415,635	174,146	447	589,781	
28	Per IURC Cause Order #44075					
29						
30	Michigan Renewable Energy Surcharge	1,333,140	3,526,165	Various	4,850,361	8,944
31						
32	Cook Life Cycle Management Program - Michigan	8,139,588	9,572,385	Various	3,030,435	14,681,538
33	Per MPSC Case U-17026					
34						
35	SFAS 106 Medicare Subsidy	8,161,078		926	1,020,135	7,140,943
36	Amort 1/2013 - 12/2024					
37						
38	Unrecovered Fuel Costs - Michigan	12,965,950	8,633,510	44x	6,702,247	14,897,213
39						
40	Unrecovered PJM Expenses		48,010,285			48,010,285
41						
42						
43						
44	TOTAL	703,726,641	356,257,048		455,572,319	604,411,370

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Rockport DSI Project - Indiana	6,567,558	4,246,604	Various	455,413	10,358,749
2	20% Non Federal Mandate Rider Portion					
3	Per IURC Cause Order #44331					
4						
5	Indiana DSM Program	2,747,934	6,331,592	908	7,856,584	1,222,942
6	Per IURC Cause Order #43287					
7						
8	Cook Life Cycle Management		10,401,788	Various	10,168,816	232,972
9	Indiana Portion					
10	Per IURC Cause Order #44182					
11						
12	Under Recovered Fuel Costs - Indiana	13,051,832	24,378,563	Various	37,430,395	
13						
14	River Transportation Selling Price Variance	3,697,146	4,776,171	417	6,304,533	2,168,784
15						
16	PJM Annual Transmission Revenue Requirement	4,705		456	4,705	
17	for Network Transmission Service					
18						
19	Cook Uprate Project	36,263,041				36,263,041
20						
21	Michigan Electric Vehicle Supply Equipment	52,343	11,917			64,260
22	Per MPSC Case U-16496					
23						
24	Clean Energy Solar Pilot Project - Indiana	146,746	1,541,488	Various	998,507	689,727
25	Per IURC Cause Order #44511					
26						
27	Under Recovered Environmental Compliance Tracker		273,675			273,675
28	Per IURC Cause Order No. 43992					
29						
30	Underrecovered FERC 205 Costs		5,446,569	565	5,446,569	
31	Per FERC Docket No. ER17-405					
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43						
44	TOTAL	703,726,641	356,257,048		455,572,319	604,411,370

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Property Taxes	40,730,219	66,629,428	408	61,987,946	45,371,701
2						
3	Property Taxes - Capital Leases	54,922	643,617	408	638,572	59,967
4						
5	Agency Fees, Factored Accts Rec	2,755,188	33,072,144	Various	33,097,485	2,729,847
6						
7	River Transport Division	357,385		Various	276,130	81,255
8						
9	Estimated Barging Bills		68,223			68,223
10						
11	Unamortized Credit Line Fees	968,934	362,885	431	650,220	681,599
12	Amortized thru June 2021					
13						
14	Defd Non-taxable Leased Assets	98,300	1,705,039	Various	1,340,887	462,452
15						
16	Minor Items	2,335	514,033	Various	510,160	6,208
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46						
47	Misc. Work in Progress	200,639				193,491
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	45,167,922				49,654,743

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 of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Accrued ARO Expense - SFAS 143	440,327,521	462,620,993
3	Reg Liability - SFAS 143 - ARO	255,914,168	330,759,257
4	Capitalized Cook Costs	4,725,000	4,725,000
5	Capitalized Interest Expense	46,425,421	50,820,464
6	SFAS 158	49,666,095	27,230,697
7	Other	28,784,214	15,446,641
8	TOTAL Electric (Enter Total of lines 2 thru 7)	825,842,419	891,603,052
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	89,135,414	205,181,550
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	914,977,833	1,096,784,602

Notes

Line 17 Other - Detail	Balance at Beginning of Year	Balance at End of Year
Non-Utility 190.2 Federal	5,664,034	2,392,732
Non-Utility 190.2 State	(332,553)	(313,446)
SFAS 133	6,461,419	3,450,930
SFAS 87	2,292,090	465,857
SFAS 109	75,050,424	199,185,477
Total	$ 89,135,414	$205,181,550

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

Balance at Beginning of Year	$914,977,833
(Less) Amounts Debited to:	
(a) Account 410.1	(101,409,204)
(b) Account 410.2 Federal	(8,381,105)
(c) Account 410.2 State	(284,287)
(d) Various	(44,555,206)
(Plus) Amounts Credited to:	
(a) Account 411.1	166,859,265
(b) Account 411.2 Federal	5,109,803
(c) Account 411.2 State	303,394
(d) Various	164,164,109
Balance at End of Year	$1,096,784,602

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.

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)
1	Common Stock	2,500,000		
2	TOTAL Common Stock	2,500,000		
3				
4	Preferred Stock - None			
5				
6				
7				
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Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (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 non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
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 purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT AS REACQUIRED STOCK (Account 217)		HELD BY RESPONDENT IN SINKING AND OTHER FUNDS		Line No.
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
1,400,000	56,583,866					1
1,400,000	56,583,866					2
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

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 total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. 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 give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on 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 which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Donations received from stockholders (Account 208)	
2	Contributed by parent company prior to 2012	972,666,991
3		
4	Subtotal Account 208	972,666,991
5		
6	Gain on reacquired capital stock (Account 210)	
7	Balance on all series	120,555
8		
9		
10	Subtotal Account 210	120,555
11		
12	Miscellaneous paid-in capital (Account 211)	
13	Amounts recorded in connection with:	
14	Merger of Indiana Service Corporation with respondent in 1948 as	
15	subsequently adjusted on December 31, 1948	1,002,503
16		
17	Acquisition of Citizen's Heat, Light and Power Company by	
18	respondent in 1954	10,687
19		
20	Merger of Michigan Power Company with respondent in 1992.	2,861,068
21	Subtotal Account 211	3,874,258
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	976,661,804

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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

1. Report by balance sheet account the particulars (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. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. 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.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 222 - Reacquired Pollution Control Revenue Bonds		
2	Reacquired Rockport Series 2002 A Pollution Control Bonds		
3	Reacquired Rockport Series D Pollution Control Bonds		17,500
4	SUBTOTAL - Account 222-Reacq PCRBs		17,500
5			
6	Account 223 - Advances From Associated Companies		
7	SUBTOTAL - Account 223-Advances From Assoc Co		
8			
9	Account 224 - Other Long Term Debt		
10	Spent Nuclear Fuel Disposal Costs Prior		
11	To April 7, 1983 - Basic Fee Assessment & Interest		
12			
13	Pollution Control Revenue Bonds		
14	Lawrenceburg, IN		
15	Series I - Variable Rate	25,000,000	178,919
16			179,337
17			
18	Series H - Variable Rate	52,000,000	331,889
19			277,847
20	Rockport, IN		
21	Series D - 2.05% Fixed Rate	40,000,000	1,157,720
22			391,775
23			
24	Series 2002 A - 2.75% Fixed Rate	50,000,000	296,785
25			325,000 D
26			136,351 D
27			444,593
28			378,717
29			74,250
30			74,250
31			74,250
32			
33	TOTAL	2,318,802,388	31,789,742

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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

1. Report by balance sheet account the particulars (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. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. 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.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Series 2009 A - 1.75% Fixed Rate	50,000,000	353,976
2	per IURC Order #43445, approved 4/9/08		249,469
3	Bonds subj to mand tender for purchase (puttable) on 6/1/18		
4			
5	Series 2009 B - 1.75% Fixed Rate	50,000,000	353,976
6	per IURC Order #43445, approved 4/9/08		249,469
7	Bonds subj to mand tender for purchase (puttable) on 6/1/18		
8			
9	Senior Unsecured Notes		
10	Series L - 3.75% Fixed Rate	300,000,000	3,139,683
11	Per IURC Authority Cause #44679		2,088,000 D
12			
13	Series K - 4.55% Fixed Rate	400,000,000	4,036,755
14			1,372,000 D
15			
16	Series H - 6.05% Fixed Rate	400,000,000	3,815,383
17			2,272,000 D
18			
19	Amortization of Cash Flow Hedges on 6.05% SUN		
20			
21	Series I - 7.00% Fixed Rate	475,000,000	3,333,197
22			3,201,500 D
23			
24	Series J - 3.20% Fixed Rate	250,000,000	1,969,707
25			402,500 D
26	Amortization of Interest Rate Swap on 3.20% SUN		
27			
28	Fort Wayne Settlement	26,802,388	
29			
30	Multiple Draw Term Loan	200,000,000	612,944
31	Variable Rate		
32	SUBTOTAL - Acct 224 - Other Long Term Debt	2,318,802,388	31,772,242
33	TOTAL	2,318,802,388	31,789,742

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, 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) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
06/01/2017	06/01/2025				-255,137	2
04/04/2013	04/01/2025				-79,965	3
					-335,102	4
						5
						6
						7
						8
						9
						10
				268,585,453		11
						12
						13
						14
5/22/2008	10/1/2019	5/22/2008	10/1/2019	25,000,000	239,428	15
3/15/2017	10/1/2019	3/15/2017	10/1/2019			16
						17
5/20/2008	11/1/2021	5/20/2008	11/1/2021	52,000,000	498,789	18
3/9/2017	11/1/2021	3/9/2017	11/1/2021			19
						20
4/25/2008	4/1/2025	4/25/2008	4/1/2025	40,000,000	601,490	21
5/16/2017	4/1/2025	5/16/2017	6/1/2021			22
						23
8/1/1985	6/1/2025	8/1/1985	6/1/2025	50,000,000	1,333,262	24
						25
						26
6/1/2007	6/1/2025	6/1/2007	6/1/2025			27
12/1/2017	6/1/2025	12/1/2017	6/1/2025			28
		6/1/2014	5/31/2015			29
		6/1/2015	5/31/2016			30
		6/1/2016	5/31/2017			31
						32
				2,574,997,049	100,206,743	33

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, 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) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
3/26/2009	6/1/2025	4/1/2009	5/31/2014	50,000,000	875,000	1
		6/1/2014	5/31/2018			2
						3
						4
3/26/2009	6/1/2025	4/1/2009	5/31/2014	50,000,000	875,000	5
		6/1/2014	5/31/2018			6
						7
						8
						9
6/29/2017	7/1/2047	6/29/2017	7/1/2047	300,000,000	5,687,500	10
						11
						12
03/03/2016	03/15/2046	03/03/2016	03/15/2046	400,000,000	18,200,000	13
						14
						15
11/14/2006	3/15/2037	11/14/2006	3/15/2037	400,000,000	24,200,000	16
						17
						18
		11/14/2006	2/28/2037		421,740	19
						20
1/15/2009	3/15/2019	1/1/2009	2/28/2019	475,000,000	33,250,000	21
						22
						23
3/18/2013	3/15/2023	3/18/2013	3/15/2023	250,000,000	8,000,000	24
						25
		3/18/2013	3/15/2023		1,606,489	26
						27
3/1/2010	2/28/2025	3/1/2010	2/28/2025	14,411,596		28
						29
5/14/2015	5/14/2018	6/1/2015	5/14/2018	200,000,000	4,753,147	30
						31
				2,574,997,049	100,541,845	32
				2,574,997,049	100,206,743	33

Schedule Page: 256 Line No.: 11 Column: h

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.

Schedule Page: 256 Line No.: 15 Column: a

On March 15, 2017, the $25 million City of Lawrenceburg Series I PCRB was re-marketed with a maturity date of 10/1/2019. This is a variable rate demand note that is puttable on demand.

Schedule Page: 256 Line No.: 18 Column: a

On March 9, 2017, the $52 million City of Lawrenceburg Series H PCRB was re-marketed with a maturity date of 11/1/2021. This is a variable rate demand note that is puttable on demand.

Schedule Page: 256 Line No.: 21 Column: a

The $40 million 2.05% City of Rockport Series D PCRB was re-marketed 5/16/2017 with a maturity date of 4/1/2025 and a mandatory tender date of 6/1/2021. Issuance expenses totaling $391,775 will be amortized through the 6/1/2021 put date.

Schedule Page: 256 Line No.: 24 Column: a

On June 3, 2002, the $50 million Series 1985A Pollution Control Bonds were re-marketed as $50 million Series 2002A Pollution Control Bonds due June 1, 2025, at a 4.9% fixed interest rate. This did not redeem the note itself but changed the method of interest calculation, the timing of the interest payments and the maturity date of the debt. These bonds were again re-marketed in June 2007 at a 4.625% fixed interest rate. There were $444,593 in issuance expenses incurred in this re-offering and no related discount. These bonds were again re-marketed in December 2017 at a 2.75% fixed interest rate(Indiana Commission Authority, Cause No. 44904). There were $378,717 in issuance expenses incurred in this re-offering and no related discount. These, plus the Issuance expenses still remaining from the Series 1985A Pollution Control Bonds, will be amortized through the June 2025 maturity date of the new Series, since no further mandatory redemption is scheduled.

An insurance policy was renewed in June of each year through June 2017 that guaranteed the principal if Indiana Michigan Power was to default on this note. This policy cost $74,250, and covered the period of June - May and was fully amortized over that policy period.

Schedule Page: 256.1 Line No.: 1 Column: a

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. Issuance expenses totaling $249,469 will be amortized through the 6/1/2018 put date.

Schedule Page: 256.1 Line No.: 1 Column: e

Subject to mandatory tender for purchase (puttable) on 6/1/2018.

Schedule Page: 256.1 Line No.: 5 Column: a

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. Issuance expenses totaling $249,469 will be amortized through the 6/1/2018 put date.

Schedule Page: 256.1 Line No.: 5 Column: e

Subject to mandatory tender for purchase (puttable) on 6/1/2018.

Schedule Page: 256.1 Line No.: 9 Column: a

The $300M 3.75% fixed rate Series L Senior Unsecured Note was issued 6/29/2017 with a maturity date of 7/1/2047. Issuance expense and discount expense will be amortized through July 2047.

Schedule Page: 256.1 Line No.: 28 Column: a

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.

Schedule Page: 256.1 Line No.: 30 Column: a

The $200 million multiple draw term loan was issued on May 14, 2015. The interest rate is variable and the maturity date is May 14, 2018. The initial draw took place on May 14, 2015 for $100 million with a subsequent draw on December 1, 2015 for $100 million.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)	186,742,763
2		
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	-327,650,029
28	Show Computation of Tax:	
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

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

Net Income for the year page 117		186,743
Federal Income Taxes		91,158
State and Local Income Taxes		(9,546)
PreTax Book Income		268,355
Increase (Decrease) in Taxable Income resuliting from:		
Allowance for Funds Used During Constructionand /Interest Capitalized		1,765
Amortization of Deferred Book Gain - Rockport Unit 1 Sale (562B)		(3,707)
Book Accruals and Deferrals		(64,994)
Book/Tax Unit Property Adj		(161,731)
Deferred Fuel Cost		11,121
Emission Allowances Net		1,360
Equity in Earnings Subsidiary Companies		(385)
Excess Tax vs Book Depreciation		(309,021)
Mark to Market		(188)
Nuclear Book Deferred Cost		8,542
Nuclear Decommissoning Costs		(270,125)
Nuclear Fuel Adjustments		30,127
Nuclear Fuel Disposal Costs		(3,405)
Pollution Control		(44,268)
Property Tax		(198)
Removal Costs		(58,517)
Relocation Costs		(2,124)
Revenue Refunds		13,549
SFAS 143 - ARO		270,729
Tax Accruals/Tax Deferrals		(20,703)
Other (Net)		(7,590)
Federal Tax Net Income - Estimated Current Year Taxable Income (Separate Return Basis)		(341,408)
Current State Income Taxes		(13,758)
Federal Taxable Income		(327,650)
Computation		
Tax*		
Federal Income Tax on Current Year Taxable Income (Separate Return Basis) at Statutory Rate of 35%		(114,678)
Adjustment due to System Consolidation	a	0
Estimated Taxes Currently Payable	b	(114,678)
Tax Provision Adjustment		0
Tax Credit C/F		(6,769)
NOL Reclass		(6,165)
Solar Investment Tax Credit		0
FIN48 Perm Items		0
Non-FIN48 Perm Items		0
R&D Credit		0
Parent Savings		0
Adjustment of Prior Years Accruals(Net)		21,098
Estimated Current Year Federal Income Taxes (Net)		(106,514)

(a) Represents the allocation of estimated current year net operating tax loss of American Electric Power Company, Inc.

(b) The Company joins in the filing of a consolidated Federal income tax return with its affiliated companies in the AEP system.
The allocation of the AEP System's consolidated Federal income tax to the System companies allocates the benefit of the current tax

losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, American Electric Power Company, Inc. is allocated to its subisidiares with taxable income. With exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidating group.

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 2017 System Federal income taxes will not be available until the consolidated Federal Income tax return is filed by October 2018.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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TAXES ACCRUED, PREPAID AND CHARGED 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 know, 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 (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) 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.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL:					
2	INCOME	-30,352,193		-106,513,856	-88,496,564	-5,043
3	FED INCOME TAX FIN48	-627,172				
4	FIT IRS AUDIT	-3,748,795				
5	FICA - 2017	3,335,185		17,941,744	18,930,863	
6	UNEMPLOYMENT - 2017	52,735		113,667	117,043	
7	EXCISE TAX - 2016	195,277		3,904	199,181	
8	EXCISE TAX - 2017			944,750	680,550	
9	SUBTOTAL Federal	-31,144,963		-87,509,791	-68,568,927	-5,043
10						
11	STATE OF INDIANA:					
12	INCOME 2014			-126	-126	
13	INCOME 2016	-4,339,764		3,577,375	-762,389	
14	INCOME 2017			-8,681,561	187,796	
15	UNEMPLOYMENT IN - 2017	28,759		88,658	94,728	
16	UTIL RECEIPTS TAX - 2016			-49,623	-49,623	
17	UTIL RECEIPTS TAX - 2017			18,501,000	18,501,000	
18						
19	INDIANA LICENSE TAX					
20	SALES & USE TAX - 2016	620,769		12,968	633,737	
21	SALES & USE TAX - 2017			5,956,443	5,188,050	
22						
23	PUBLI SERV COMM-2016		363,709	727,418	363,709	
24	PUBLI SERV COMM-2017			871,649	1,305,837	
25						
26	REAL & PERS PROP-2015					
27	REAL & PERS PROP-2016	18,752,532		21,851	18,774,383	
28	REAL & PERS PROP-2017			17,865,521	2,137	
29						
30	PERS PROP LEASED-2016	522,925		57,332	580,257	
31	PERS PROP LEASED-2017			583,650		
32						
33	REAL PROP LEASED-2017			225,631	225,631	
34						
35	SUBTOTAL Indiana	15,585,221	363,709	39,758,186	45,045,127	
36						
37						
38						
39						
40	STATE OF KENTUCKY:					
41	TOTAL	40,500,980	1,054,889	-2,926,597	15,965,304	-5,143

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TAXES ACCRUED, PREPAID AND CHARGED 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 know, 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 (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) 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.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1						
2	KY INCOME 2016	-207,382		42,911	-164,471	
3	KY INCOME 2017			6,738	164,471	
4	Subtotal Kentucky	-207,382		49,649		
5	STATE OF MICHIGAN:					
6	MI INCOME 2016	-756,594		971,520	214,926	
7	MI INCOME 2017			-1,426,042	183,286	
8	MI SBT					
9	MI CITIES	-1,261				
10	UNEMPLOYMENT - 2017	204,904		393,837	430,087	
11	PUBL SERV COMM'S-2016		101,188	466,732	365,544	
12	PUBL SERV COMM'S-2017			252,693	417,918	
13	USE TAX-2016	208,927	127,891	7,100	88,136	
14	USE TAX - 2017			1,689,176	1,483,602	
15	USE TAX - REFUNDS			-1,009,185	-1,009,185	
16	SALES TAX - 2016		462,101		-462,101	
17	SALES TAX - 2017				502,812	
18						
19	REAL & PERS PROP-2012					
20	REAL & PERS PROP-2013					
21	REAL & PERS PROP-2014					
22	REAL & PERS PROP-2015	10,711,702		35,237	10,746,939	
23	REAL & PERS PROP-2016	40,710,926		1,312,146	30,296,653	
24	REAL & PERS PROP-2017			45,351,975		
25						
26	PERS PROP LEASED-2015	23,858		-15,637	8,221	
27	PERS PROP LEASED-2016	54,922			35,479	
28	PERS PROP LEASED-2017			59,967		
29						
30	REAL PROP LEASED-2015	40,291		-10,471	29,820	
31	REAL PROP LEASED-2016			201,000	170,228	
32						
33	SUBTOTAL Michigan	51,197,675	691,180	48,280,048	43,502,365	
34						
35	DE License Tax			300	300	
36	SUBTOTAL DELAWARE			300	300	
37						
38						
39						
40						
41	TOTAL	40,500,980	1,054,889	-2,926,597	15,965,304	-5,143

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TAXES ACCRUED, PREPAID AND CHARGED 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 know, 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 (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) 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.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1						
2						
3						
4						
5	STATE OF WEST VIRGINIA:					
6	LICENSE TAX					
7	WV FRANCHISE-2013			2,584	2,584	
8	WV FRANCHISE-2014			12,654	12,654	
9	WEST VA INC TAX-2012			-1,189		1,189
10	WEST VA INC TAX-2013			-2,584		2,584
11	WEST VA INC TAX-2014			-12,654		12,654
12	WEST VA INC TAX-2015			-1,488		1,488
13	WEST VA INC TAX-2016	-1,666,183		969,201	-696,982	
14	WEST VA INC TAX-2017			-156,224	-1,155,641	-17,915
15						
16	REAL & PERS PROP-2015					
17	REAL & PERS PROP-2016	15,985		-2,533	13,452	
18	REAL & PERS PROP-2017			13,000		
19						
20	WV USE TAX - 2016	967			967	
21	WV USE TAX - 2017			19,538	18,140	
22	WV EXCISE TAX - 2016	22,589		-5	22,584	
23	WV EXCISE TAX - 2017			133,601	92,330	
24	WV EXCISE TAX - Provision	10,700		-10,700		
25	UNEMPLOYMENT - 2017	3		42,259	41,533	
26	SUBTOTAL West Virginia	-1,615,939		1,005,460	-1,648,379	
27						
28	STATE OF OHIO:					
29	OHIO FRANCH TAX - 2008					
30	OHIO INCOME TAX					
31	OHIO CAT TAX - 2016	27,600		-44,875	-17,275	
32	OHIO CAT TAX - 2017			50,591	24,491	
33	OHIO CAT TAX - Audit			-1,104,484	-1,104,484	
34	State Unemployment 2017	81			-70	
35	SUBTOTAL Ohio	27,681		-1,098,768	-1,097,338	
36	STATE OF ILLINOIS:					
37	IL INCOME TAX - 2006					
38	IL INCOME TAX - 2012			13,877		-13,877
39	IL INCOME TAX - 2016	-323,145		4,974	-286,000	-30,444
40	IL INCOME TAX - 2017			-207,027	79,000	44,321
41	TOTAL	40,500,980	1,054,889	-2,926,597	15,965,304	-5,143

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2017/Q4

TAXES ACCRUED, PREPAID AND CHARGED 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 know, 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 (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) 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.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	SUBTOTAL Illinois	-323,145		-188,176	-207,000	
2	STATE OF LOUISIANA:					
3	LA Franchise Tax					
4						
5	SUBTOTAL Louisiana					
6						
7	STATE OF PA:					
8	PA Gross Receipts Audit	239,325				
9						
10	SUBTOTAL Pennsylvania	239,325				
11						
12	RAILCAR PROP TAX:					
13	Misc States - 2012			6	6	
14	Misc States - 2016			24,109	24,109	
15	Misc States - 2017			31,349	31,349	
16	SUBTOTAL Railcar Prop Tax			55,464	55,464	
17						
18	STATE OF MISSOURI					
19	UNEMPLOYMENT - 2017					
20	MO INCOME TAX - 2016	-1,234		70	-1,164	
21	MO INCOME TAX - 2017			317	1,164	
22	MO FRANCHISE					
23	SUBTOTAL Missouri	-1,234		387		
24						
25	MISC RTD PROP TX-2015	297,542		-297,542		
26	MISC RTD PROP TX-2016	1,113,498		-839,252		
27	MISC RTD PROP TX-2017			1,147,552		
28						
29	STATE INCOME TAX FIN-48	5,332,701		-3,290,377	-1,116,471	
30						
31	MICHIGAN LICENSE TAX			50	50	
32	VARIOUS LICENSE TAX			113	113	
33						
34	VARIOUS FRANCHISE TAX			100		-100
35						
36	SIT LONG TERM					
37						
38						
39						
40						
41	TOTAL	40,500,980	1,054,889	-2,926,597	15,965,304	-5,143

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) 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 (i) through (l) how the taxes were distributed. Report in column (l) 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 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) 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.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-48,374,528		-107,960,156			1,446,300	2
-627,172						3
-3,748,795						4
2,346,066		11,468,629			6,473,115	5
49,359		66,563			47,104	6
					3,904	7
264,200		11,961			932,789	8
-50,090,870		-96,413,003			8,903,212	9
						10
						11
		-126				12
		3,596,066			-18,691	13
-8,869,357		-9,208,458			526,897	14
22,689		53,901			34,757	15
		-49,083			-540	16
		18,501,000				17
						18
						19
					12,968	20
768,393					5,956,443	21
						22
		727,418				23
	434,188	871,649				24
						25
		-60,504			60,504	26
		238,133			-216,282	27
17,863,384		17,333,699			531,822	28
						29
		57,332				30
583,650		583,650				31
						32
					225,631	33
						34
10,368,759	434,188	32,644,677			7,113,509	35
						36
						37
						38
						39
						40
21,741,646	1,192,599	-27,964,455			25,037,858	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) 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 (i) through (l) how the taxes were distributed. Report in column (l) 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 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) 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.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
		25,951			16,960	2
-157,733		112			6,626	3
-157,733		26,063			23,586	4
						5
		995,124			-23,604	6
-1,609,328		-1,533,216			107,174	7
						8
-1,261						9
168,654		286,577			107,260	10
		466,732				11
	165,225	252,693				12
		9,899			-2,799	13
295,948	90,374	95,407			1,593,769	14
		-56,078			-953,107	15
						16
	502,812					17
						18
		142,470			-142,470	19
		145,874			-145,874	20
		-276,251			276,251	21
		-52,424			87,661	22
11,726,419		38,711,743			-37,399,597	23
45,351,975					45,351,975	24
						25
		-15,637				26
19,443		54,922			-54,922	27
59,967					59,967	28
						29
		-10,471				30
30,772		201,000				31
						32
56,042,589	758,411	39,418,364			8,861,684	33
						34
		300				35
		300				36
						37
						38
						39
						40
21,741,646	1,192,599	-27,964,455			25,037,858	41

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) 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 (i) through (l) how the taxes were distributed. Report in column (l) 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 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) 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.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
						3
						4
						5
						6
		2,584				7
		12,654				8
		-1,189				9
		-2,584				10
		-12,654				11
		-1,488				12
		966,480			2,721	13
981,502		-15,430			-140,794	14
						15
		3,308			-3,308	16
		3,246			-5,779	17
13,000					13,000	18
						19
						20
1,398					19,538	21
					-5	22
41,271					133,601	23
					-10,700	24
729		-8,108			50,367	25
1,037,900		946,819			58,641	26
						27
						28
						29
						30
		-44,875				31
26,100		50,591				32
		-1,104,484				33
151		70			-70	34
26,251		-1,098,698			-70	35
						36
						37
		13,877				38
-62,615		4,433			541	39
-241,706		-221,628			14,601	40
21,741,646	1,192,599	-27,964,455			25,037,858	41

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) 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 (i) through (l) how the taxes were distributed. Report in column (l) 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 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) 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.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
-304,321		-203,318			15,142	1
						2
						3
						4
						5
						6
						7
239,325						8
						9
239,325						10
						11
						12
					6	13
		426			23,683	14
					31,349	15
		426			55,038	16
						17
						18
						19
		71			-1	20
-847		295			22	21
						22
-847		366			21	23
						24
					-297,542	25
274,246					-839,252	26
1,147,552					1,147,552	27
						28
3,158,795		-3,286,714			-3,663	29
						30
		50				31
		113				32
						33
		100				34
						35
						36
						37
						38
						39
						40
21,741,646	1,192,599	-27,964,455			25,037,858	41

Schedule Page: 262 Line No.: 2 Column: f

($5,043) - Fuel Tax Credit

Schedule Page: 262.1 Line No.: 16 Column: a

Consists of a prepayment for sales tax only; a collect & remit tax. Beginning in 2009,included for purpose of reporting all prepaid tax activity.

Schedule Page: 262.1 Line No.: 17 Column: a

Consists of a prepayment for sales tax only; a collect & remit tax. Beginning in 2009, included for purpose of reporting all prepaid tax activity.

Schedule Page: 262.2 Line No.: 9 Column: f

$1,189 - Reclass WV State Income Tax

Schedule Page: 262.2 Line No.: 10 Column: f

$2,584 - Reclass WV State Income Tax

Schedule Page: 262.2 Line No.: 11 Column: f

$12,654 - Reclass WV State Income Tax

Schedule Page: 262.2 Line No.: 12 Column: f

$1,488 - Reclass WV State Income Tax

Schedule Page: 262.2 Line No.: 14 Column: f

($17,915) - Reclass WV State Income Tax

Schedule Page: 262.2 Line No.: 38 Column: f

($13,877) - Reclass Illinois State Income Tax

Schedule Page: 262.2 Line No.: 39 Column: f

($30,444) - Reclass Illinois State Income Tax

Schedule Page: 262.2 Line No.: 40 Column: f

$44,321 - Reclass Illinois State Income Tax

Schedule Page: 262.3 Line No.: 34 Column: f

($100) - Intercompany Transfer Franchise Tax

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	28,842,181			4114	4,705,788	
6	Solar ITC 30%	9,939,234					
7							
8	TOTAL	38,781,415				4,705,788	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
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48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
24,136,393			5
9,939,234			6
			7
34,075,627			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
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			48

Schedule Page: 266 Line No.: 8 Column: i

Remaining amortization period is 20 years.

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

OTHER DEFFERED 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	Defd Gain-Sale of Rockport Unit 2	21,991,217	507	3,706,716		18,284,501
2	Amtz Period 12/1989-12/2022					
3						
4	Pole Attachment Rentals	566,286	454	1,780,429	1,805,822	591,679
5						
6	IPP-System Upgrade Credits	3,204,471			125,071	3,329,542
7						
8	Defd Gain-Fiber Optics Agrmt	3,985,539	411.6	285,054		3,700,485
9	In Kind Service-Amrtz thru 2025					
10						
11	Deferred Revenues-Verizon	296,498	451	47,439		249,059
12	Amortized thru March 2023					
13						
14	Deferred Revenues-KDL	51,618	451	9,348		42,270
15	Amortized thru Dec 2022					
16						
17	Customer Advance Receipts	5,780,310	142	5,780,310	6,176,200	6,176,200
18						
19	Federal Mitigation Deferral (NSR)	2,052,907				2,052,907
20						
21	SEMCO Agreement - MGP Sites	2,336,215	242 / 426.5	2,336,215		
22						
23	Contract Settlement Reserves	342,762	186	299,503		43,259
24						
25	Minor Items	846,698	Various	1,377,708	911,957	380,947
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	41,454,521		15,622,722	9,019,050	34,850,849

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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.

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)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	13,008,872	16,422,234	
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	13,008,872	16,422,234	
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16	Other			
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	13,008,872	16,422,234	
18	Classification of TOTAL			
19	Federal Income Tax	13,008,872	16,422,234	
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
							3
						29,431,106	4
							5
							6
							7
						29,431,106	8
							9
							10
							11
							12
							13
							14
							15
		Various	11,772,442			-11,772,442	16
			11,772,442			17,658,664	17
							18
			11,772,442			17,658,664	19
							20
							21

NOTES (Continued)

Schedule Page: 272   Line No.: 16   Column: b

	Balance at Beginning of Year	Balance at End of Year
NON-UTILITY	0	0
SFAS 133	0	0
SFAS 109	0	11,772,442
Total Line 16	0	11,772,442

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ACCUMULATED DEFFERED 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.

Line No.	Account	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Account 282			
2	Electric	1,200,135,173	287,426,004	108,250,633
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,200,135,173	287,426,004	108,250,633
6	Non-Utility	852,070		
7	SFAS 109/FIN 48	105,266,362		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,306,253,605	287,426,004	108,250,633
10	Classification of TOTAL			
11	Federal Income Tax	1,306,253,605	287,426,004	108,250,633
12	State Income Tax			
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
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)	Line No.
							1
						1,379,310,544	2
							3
							4
						1,379,310,544	5
53,897	567,424					338,543	6
		Various	631,936,660	Various	33,524,558	-493,145,740	7
							8
53,897	567,424		631,936,660		33,524,558	886,503,347	9
							10
53,897	567,424		631,936,660		33,524,558	886,503,347	11
							12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ACCUMULATED DEFFERED 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.

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)
1	Account 283			
2	Electric			
3	SFAS 158	49,666,095	1,195,980	23,631,378
4	Reg Asset - SFAS 143 - ARO	681,443,844	94,543,694	39,135
5	Deferred Cook O&M Restart Cost	26,321,101	16,616,364	19,605,945
6	Nuclear Fuel	17,670,719	47,261,826	59,731,189
7	Mark To Market	456,024	3,741,775	6,345,199
8	Other	70,927,476	48,272,689	35,508,921
9	TOTAL Electric (Total of lines 3 thru 8)	846,485,259	211,632,328	144,861,767
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	274,953,899		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	1,121,439,158	211,632,328	144,861,767
20	Classification of TOTAL			
21	Federal Income Tax	962,927,217	211,632,328	144,861,767
22	State Income Tax	158,511,941		
23	Local Income Tax			

NOTES

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
						27,230,697	3
						775,948,403	4
						23,331,520	5
						5,201,356	6
						-2,147,400	7
9,291,386	6,303,302					86,679,328	8
9,291,386	6,303,302					916,243,904	9
							10
							11
							12
							13
							14
							15
							16
							17
2,082,488	3,703,214	Various	107,581,871	Various	64,275,726	230,027,028	18
11,373,874	10,006,516		107,581,871		64,275,726	1,146,270,932	19
							20
11,373,874	10,006,516		103,111,082		37,962,137	965,916,191	21
			4,470,789		26,313,589	180,354,741	22
							23

NOTES (Continued)

Schedule Page: 276   Line No.: 18   Column: b

	Balance at Beginning of Year	Balance at End of Year
NON-UTILITY	2,594,016	973,289
SFAS 133	0	0
SFAS 109	272,359,883	229,053,739
Total Line 18	274,953,899	230,027,028

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Unrealized Gain on Forward Commitments	(3,462,994)	456	9,250,428	7,276,184	-5,437,238
2						
3	Netting of Trading Activities Related to	5,909,692	182	4,431,190	3,958,736	5,437,238
4	Unrealized Gains/Losses on Forward Commitments					
5	Between Regulated Assets/Liabilities					
6						
7	Asset Retirement Oblig-Excess Provision SFAS 143	731,183,336	228	31,594,889	245,438,000	945,026,447
8						
9	SNF Trust Funds - Pre 4/83	44,222,709	Various	4,312,689	3,247,282	43,157,302
10						
11	Gains on Foreign Currency Derivatives	79,163	403	11,309		67,854
12	Amortz 1/2009 - 12/2023					
13						
14	SFAS 109 Deferred FIT	23,372,009	Various	18,104,275	733,663,099	738,930,833
15						
16	Over Recovered Environmental Compliance Tracker	415,633	509	415,633		
17	Per IURC Cause No. 43992					
18						
19	DSI Federal Mandate Rider - Indiana	1,688,023	Various	2,829,275	1,527,810	386,558
20	Per IURC Cause No. 44331					
21						
22	Cook Life Cycle Management - Indiana	4,424,777	Various	13,858,715	11,830,672	2,396,734
23	Per IURC Cause No. 44182					
24						
25	Indiana Clean Coal Technology Rider	300,504	Various	1,305,279	1,490,796	486,021
26	Per IURC Cause No. 44523					
27						
28	Distribution Storm Expense	1,151,125	593	1,317,063	4,135,074	3,969,136
29	Per IURC Cause No. 44075					
30						
31	Over Recovered PJM Expenses	4,180,211	447	4,180,211		
32						
33	Over Recovered Fuel Costs - Indiana				2,655,795	2,655,795
34						
35	Michigan Renewable Energy Surcharge				2,732,127	2,732,127
36						
37	Capacity Settlement - IN Portion				1,401,549	1,401,549
38	Per IURC Cause No. 44075					
39						
40	Other Comprehensive Inc - Excess Def FIT		190	2,300,609		-2,300,609
41	TOTAL	813,464,188		93,911,565	1,019,357,124	1,738,909,747

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	614,666,474	627,199,180
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	440,178,474	443,620,125
5	Large (or Ind.) (See Instr. 4)	513,022,496	514,618,990
6	(444) Public Street and Highway Lighting	7,090,998	7,064,047
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,574,958,442	1,592,502,342
11	(447) Sales for Resale	442,541,960	481,694,670
12	TOTAL Sales of Electricity	2,017,500,402	2,074,197,012
13	(Less) (449.1) Provision for Rate Refunds	11,613,362	1,133,525
14	TOTAL Revenues Net of Prov. for Refunds	2,005,887,040	2,073,063,487
15	Other Operating Revenues		
16	(450) Forfeited Discounts	5,031,510	4,950,765
17	(451) Miscellaneous Service Revenues	4,136,785	4,843,933
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	7,085,791	6,964,833
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	2,636,132	2,147,866
22	(456.1) Revenues from Transmission of Electricity of Others	26,863,751	40,184,190
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	45,753,969	59,091,587
27	TOTAL Electric Operating Revenues	2,051,641,009	2,132,155,074

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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 pages 108-109, 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.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
5,310,766	5,577,764	514,523	512,004	2
				3
4,825,935	4,979,076	70,604	70,161	4
7,740,115	7,779,710	4,923	4,938	5
69,755	71,070	1,934	1,938	6
				7
				8
				9
17,946,571	18,407,620	591,984	589,041	10
11,873,382	9,971,793	30	46	11
29,819,953	28,379,413	592,014	589,087	12
				13
29,819,953	28,379,413	592,014	589,087	14

Line 12, column (b) includes $ 4,681,205 of unbilled revenues.

Line 12, column (d) includes 27,031 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 10 Column: b

Detail of Unmetered Sales:

	Revenue	MWH	Average Customers
Residential	2,749,411	14,224	19,250
Commercial	4,726,972	29,645	10,638
Industrial	1,000,611	6,613	1,367
Public Street Lighting	65,519	408	121
Total	8,542,513	50,890	31,376

Schedule Page: 300 Line No.: 10 Column: c

Detail of Unmetered Sales:

	Revenue	MWH	Average Customers
Residential	2,756,388	14,324	19,313
Commercial	4,724,960	29,645	10,651
Industrial	964,028	6,384	1,363
Public Street Lighting	65,226	407	121
Total	8,510,602	50,760	31,448

Schedule Page: 300 Line No.: 17 Column: b

Customer service revenue, including connects, reconnects, disconnects, temporary services and other charges billed to customers.

Schedule Page: 300 Line No.: 21 Column: b

	2017	2016
Associated Business Development	2,533,734	1,867,009
DSM Revenues	97,820	246,754
Misc Revenues <$250,000	4,578	34,103
Total	2,636,132	2,147,866

Schedule Page: 300 Line No.: 22 Column: b

PJM Revenues

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)
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					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. 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	440 RESIDENTIAL SALES					
2	Residential Service	5,156,032	603,556,903	505,960	10,191	0.1171
3	Residential Service TOD	90,940	9,414,163	5,734	15,860	0.1035
4	Res Off-Peak Energy Stor	27,121	2,485,220	1,301	20,846	0.0916
5	Res Svc Opt Senior Citizen	8,115	781,614	1,528	5,311	0.0963
6	Outdoor Lighting (Indiana)	14,224	2,749,411			0.1933
7	Indiana Riders		-567,752			
8	Unrecovered Fuel		-6,447,850			
9	Subtotal Billed	5,296,432	611,971,709	514,523	10,294	0.1155
10	Unbilled Revenue	14,334	2,694,765			0.1880
11	Total Residential	5,310,766	614,666,474	514,523	10,322	0.1157
12						
13	442 COMMERCIAL SALES					
14	Residential Service	2	282			0.1410
15	Energy Conserv Lighting Svc	103	17,925	6	17,167	0.1740
16	Electric Heating General	8,500	1,010,311	184	46,196	0.1189
17	Electric Heating Schools	5,209	442,698	15	347,267	0.0850
18	Irrigation Service	12,553	1,477,935	649	19,342	0.1177
19	Small General Service	80,478	12,947,061	13,016	6,183	0.1609
20	Small General Service TOD	1,289	161,672	103	12,515	0.1254
21	Medium General Service	1,452,241	163,192,116	49,507	29,334	0.1124
22	Medium General Service TOD	61,415	5,897,140	1,536	39,984	0.0960
23	Large General Service	1,970,573	165,602,906	3,420	576,191	0.0840
24	Large General Service TOD	80,799	6,372,683	443	182,391	0.0789
25	Large Power	112,111	8,657,111	5	22,422,200	0.0772
26	Industrial Service	781,304	53,902,946	91	8,585,758	0.0690
27	Street Lighting Service	21	2,597	3	7,000	0.1237
28	Water & Sewage Service	157,071	11,499,802	645	243,521	0.0732
29	Municipal & School Service	55,239	5,373,822	468	118,032	0.0973
30	Street Light - Cust Owned - Meter	4,576	256,368	513	8,920	0.0560
31	Outdoor Lighting	29,645	4,726,972			0.1595
32	Indiana Riders		-274,450			
33	Unrecovered Fuel		-2,688,660			
34	Estimated Revenue	9,063	521,783			0.0576
35	Subtotal Billed	4,822,192	439,101,020	70,604	68,299	0.0911
36	Unbilled Revenue	3,743	1,077,454			0.2879
37	Total Commercial	4,825,935	440,178,474	70,604	68,352	0.0912
38						
39						
40						
41	TOTAL Billed	17,919,540	1,570,277,237	591,984	30,270	0.0876
42	Total Unbilled Rev.(See Instr. 6)	27,031	4,681,205	0	0	0.1732
43	TOTAL	17,946,571	1,574,958,442	591,984	30,316	0.0878

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. 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	442 INDUSTRIAL SALES					
2	Electric Heating General	803	95,438	11	73,000	0.1189
3	Small General Service	2,970	441,315	374	7,941	0.1486
4	Medium General Service	506,942	54,535,657	3,386	149,717	0.1076
5	Medium General Service - TOD	3,044	286,992	48	63,417	0.0943
6	Large General Service	825,489	70,996,088	817	1,010,390	0.0860
7	Large General Service - TOD	4,136	359,215	10	413,600	0.0869
8	Large Power	672,935	53,661,973	90	7,477,056	0.0797
9	Industrial Service	5,701,826	335,548,813	177	32,213,706	0.0588
10	Water & Sewage Service	7,984	576,283	9	887,111	0.0722
11	Outdoor Lighting	6,612	1,000,611			0.1513
12	Indiana Riders		-274,441			
13	Energy Conserv Lighting	36	5,427	1	36,000	0.1508
14	Estimated Revenue	-1,598	-60,706			0.0380
15	Unrecovered Fuel		-5,052,687			
16	Subtotal Billed	7,731,179	512,119,978	4,923	1,570,420	0.0662
17	Unbilled Revenue	8,936	902,518			0.1010
18	Total Industrial	7,740,115	513,022,496	4,923	1,572,235	0.0663
19						
20	444 PUBLIC STREET LIGHTING					
21	Small General Service	516	116,498	233	2,215	0.2258
22	Medium General Service	2,848	420,740	943	3,020	0.1477
23	Ft Wayne Street Lighting	25,343	981,887	1	25,343,000	0.0387
24	Energy Conservation Lighting	23,624	3,984,663	201	117,532	0.1687
25	Street Light - Customer Owned	3,031	197,394	35	86,600	0.0651
26	Street Lighting Service	7,576	947,615	86	88,093	0.1251
27	Municipal & School Service	297	38,822	35	8,486	0.1307
28	Street Light - Cust Owned - Meter	6,186	329,150	361	17,136	0.0532
29	Estimated Revenue	-246	13,221			-0.0537
30	Small General Service - TOD	154	18,448	39	3,949	0.1198
31	Outdoor Lighting	408	65,519			0.1606
32	Unrecovered Fuel		-29,427			
33	Subtotal Billed	69,737	7,084,530	1,934	36,058	0.1016
34	Unbilled Revenue	18	6,468			0.3593
35	Total Public Street Lighting	69,755	7,090,998	1,934	36,068	0.1017
36						
37						
38	Instruction 5. (See Note)					
39						
40						
41	TOTAL Billed	17,919,540	1,570,277,237	591,984	30,270	0.0876
42	Total Unbilled Rev.(See Instr. 6)	27,031	4,681,205	0	0	0.1732
43	TOTAL	17,946,571	1,574,958,442	591,984	30,316	0.0878

Schedule Page: 304.1 Line No.: 38 Column: a

		FUEL CLAUSE
440	RESIDENTIAL SALES	
	RESIDENTIAL SERVICE	1,521,599
	RESIDENTIAL SERVICE TOD	773,848
	RES OFF-PEAK ENERGY STORAGE	110,041
	RES SVC OPT SENIOR CITIZEN	85,241
	OUTDOOR LIGHTING (INDIANA)	16,070
	Unbilled	65,182
	TOTAL RESIDENTIAL SALES	2,571,981
442	COMMERCIAL SALES	
	RESIDENTIAL SERVICE	(2)
	ENERGY CONSERV LIGHTING SVC	(233)
	ELECTRIC HEATING GENERAL	21,590
	ELECTRIC HEATING SCHOOLS	54,694
	IRRIGATION SERVICE	117,985
	SMALL GENERAL SERVICE	838,671
	MEDIUM GENERAL SERVICE	1,829,081
	MEDIUM GENERAL SERVICE TOD	4,242
	LARGE GENERAL SERVICE	(3,004,068)
	LARGE GENERAL SERVICE-TOD	(192,595)
	LARGE POWER	1,177,170
	SMALL GENERAL SERVICE TOD	3,814
	INDUSTRIAL SERVICE	(1,808,525)
	MUNICIPAL AND SCHOOL SERVICE	189,707
	OUTDOOR LIGHTING (INDIANA)	10,729
	WATER AND SEWAGE SERVICE	(35,709)
	SL CUST-OWNED SYS METERED	(10,670)
	STREET LIGHTING SERVICE	176
	Unbilled	(22,638)
	Estimated	(21,789)
	TOTAL COMMERCIAL SALES	(848,370)
442	INDUSTRIAL SALES	
	ENERGY CONSERV LIGHTING SVC	(82)
	ELECTRIC HEATING GENERAL	2,810
	SMALL GENERAL SERVICE	31,184
	MEDIUM GENERAL SERVICE	1,239,243
	MEDIUM GENERAL SERVICE TOD	(5,591)
	LARGE GENERAL SERVICE	(1,298,914)
	LARGE GENERAL SERVICE-TOD	(9,923)
	LARGE POWER	5,730,344
	WATER AND SEWAGE SERVICE	(19,160)
	INDUSTRIAL SERVICE	(13,124,361)
	OUTDOOR LIGHTING (INDIANA)	(4,307)
	Unbilled	(53,692)
	Estimated	(12,326)
	TOTAL INDUSTRIAL SALES	(7,524,775)
444	PUBLIC STREET LIGHTING	
	ENERGY CONSERV LIGHTING SVC	12,079
	SMALL GENERAL SERVICE	3,521
	SMALL GENERAL SERVICE - TOD	(354)
	MEDIUM GENERAL SERVICE	(5,856)
	MUNICIPAL AND SCHOOL SERVICE	(17)
	FORT WAYNE STREET LIGHTING	(53,300)
	OUTDOOR LIGHTING (INDIANA)	431
	SL CUST-OWNED SYS	(177)
	SL CUST-OWNED SYS METERED	(9,109)
	STREET LIGHTING SERVICE	34,374
	Unbilled	(372)
	Estimated	(3,392)

TOTAL PUBLIC STREET LIGHTING	(22,172)
TOTAL FUEL CLAUSE	(5,823,336)

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

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 326-327).
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.

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)	Average Monthly CP Demand (f)
1	CITY OF AUBURN	RQ	Note 1			
2	CITY OF BLUFFTON	RQ	Note 1			
3	CITY OF DOWAGIAC, MI	RQ	Note 1			
4	CITY OF GARRETT	RQ	Note 1			
5	CITY OF MISHAWAKA	RQ	Note 1			
6	CITY OF NILES	RQ	Note 1			
7	CITY OF SOUTH HAVEN	RQ	Note 1			
8	CITY OF STURGIS	RQ	Note 1			
9	INDIANA MUNICIPAL POWER AGENCY	RQ	Note 1			
10	PJM TRANSMISSION FOR RQ	RQ	Various			
11	TOWN OF AVILA	RQ	Note 1			
12	TOWN OF NEW CARLISLE	RQ	Note 1			
13	TOWN OF WARREN	RQ	Note 1			
14	VILLAGE OF PAW PAW	RQ	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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 326-327).
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.
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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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	WABASH VALLEY POWER ASSN INC.	RQ	Note 1			
2	ADVAN PROMOTIONS INC.	OS	Note 1			
3	ALLEGHENY ELECTRIC COOPERATIVE	OS	Note 1			
4	AMEREN CILCO	OS	Note 1			
5	AMEREX POWER, LTD	OS	Note 1			
6	BGC FINANCIAL LP	OS	Note 1			
7	CALIFORNIA ISO	OS	Note 1			
8	CALIFORNIA POWER EXCHANGE	OS	Note 1			
9	CITY OF BANGOR, WISCONSIN	OS	Note 1			
10	CITY OF BARRON, WISCONSIN	OS	Note 1			
11	CITY OF BLOOMER, WISCONSIN	OS	Note 1			
12	CITY OF CORNELL, WISCONSIN	OS	Note 1			
13	CITY OF MEDFORD	OS	Note 1			
14	CITY OF RICE LAKE UTILITIES	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SALES FOR RESALE (Account 447)

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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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (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)
1	CITY OF SPOONER, WISCONSIN	OS	Note 1			
2	CITY OF WAKEFIELD, WISCONSIN	OS	Note 1			
3	CITY OF WESTERVILLE	OS	Note 1			
4	COMMONWEALTH EDISON COMPANY	OS	Note 1			
5	DP&L POWER SERVICES	OS	Note 1			
6	DUKE ENERGY OHIO, INC	OS	Note 1			
7	DUQUESNE LIGHT COMPANY	OS	Note 1			
8	EOH HOLDINGS, LLC	OS	Note 1			
9	EVOLUTION MARKETS FUTURES, LLC	OS	Note 1			
10	FEDERAL ENERGY REGULATORY	OS	Note 1			
11	GFI SECURITIES LLC	OS	Note 1			
12	ICAP ENERGY LLC	OS	Note 1			
13	ICE TRADE VAULT LLC	OS	Note 1			
14	IVG ENERGY, LTD	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SALES FOR RESALE (Account 447)

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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)	Average Monthly CP Demand (f)
1	MIDWEST ISO	OS	Note 1			
2	MIZUHO SECURITIES USA INC	OS	Note 1			
3	OHIO POWER COMPANY (AUCTION)	OS	Note 1			
4	OVER/UNDER CAPACITY TRACKER	OS	Note 1			
5	OVER/UNDER PJM EXP TRACKER	OS	Note 1			
6	OVER/UNDER PJM TRACKER	OS	Note 1			
7	PJM INTERCONNECTION	OS	Note 1			
8	RBC CAPITAL MARKET, LLC	OS	Note 1			
9	SPSR2 - MAREX SPECTRON	OS	Note 1			
10	TFS ENERGY FUTURES, LLC	OS	Note 1			
11	TIMBER CANYON	OS	Note 1			
12	TOWN OF HAGERSTOWN, INDIANA	OS	Note 1			
13	TULLETT PREBON AMERICAS CORP.	OS	Note 1			
14	TVA BULK POWER TRADING	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SALES FOR RESALE (Account 447)

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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	UBS AG, LONDON BRANCH	OS	Note 1			
2	VILLAGE OF CADOTT, WISCONSIN	OS	Note 1			
3	VILLAGE OF TREMPEALEAU, WISCONSIN	OS	Note 1			
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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 (9) 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,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
434,660	17,588,364	11,114,026		28,702,390	1
279,779	10,373,790	7,316,000		17,689,790	2
67,315	2,888,800	1,874,336		4,763,136	3
88,530	3,762,175	2,460,269		6,222,444	4
604,889	25,354,910	17,494,276		42,849,186	5
125,092	5,350,969	3,607,913		8,958,882	6
144,045	5,930,721	4,317,193		10,247,914	7
219,010	9,561,740	6,292,904		15,854,644	8
1,626,346	53,636,396	35,797,043		89,433,439	9
			-61,481,776	-61,481,776	10
36,426	1,416,460	1,002,877		2,419,337	11
11,385	505,322	393,698		899,020	12
17,828	751,202	506,348		1,257,550	13
43,270	1,850,890	1,396,842		3,247,732	14
4,962,057	188,464,398	127,747,888	-61,481,776	254,730,510	
6,911,325	-1,817,184	189,628,634	0	187,811,450	
11,873,382	**186,647,214**	**317,376,522**	**-61,481,776**	**442,541,960**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SALES FOR RESALE (Account 447) (Continued)

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 (9) 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,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,263,482	49,492,659	34,174,163		83,666,822	1
		-6,795		-6,795	2
15,201		711,210		711,210	3
		-1,542		-1,542	4
		-12,374		-12,374	5
		-2,969		-2,969	6
		38,527		38,527	7
		-1,969		-1,969	8
7		-4,231		-4,231	9
-73		-20,046		-20,046	10
-94		-15,930		-15,930	11
2		-2,112		-2,112	12
169		-13,417		-13,417	13
-206		-41,576		-41,576	14
4,962,057	188,464,398	127,747,888	-61,481,776	254,730,510	
6,911,325	-1,817,184	189,628,634	0	187,811,450	
11,873,382	**186,647,214**	**317,376,522**	**-61,481,776**	**442,541,960**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SALES FOR RESALE (Account 447) (Continued)

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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 (9) through (k)
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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,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		1,062		1,062	1
-8		-2,582		-2,582	2
-46		3,376		3,376	3
94,295		3,383,564		3,383,564	4
59,174		3,044,859		3,044,859	5
118,208		5,916,835		5,916,835	6
215,762		10,962,733		10,962,733	7
		-258		-258	8
		-4,165		-4,165	9
		9,827		9,827	10
		-25		-25	11
		-32,332		-32,332	12
		-12,083		-12,083	13
		-13,605		-13,605	14
4,962,057	188,464,398	127,747,888	-61,481,776	254,730,510	
6,911,325	-1,817,184	189,628,634	0	187,811,450	
11,873,382	**186,647,214**	**317,376,522**	**-61,481,776**	**442,541,960**	

SALES FOR RESALE (Account 447) (Continued)

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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.
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10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
237		190,923		190,923	1
		340,045		340,045	2
75,126		3,791,583		3,791,583	3
	-1,817,184			-1,817,184	4
		4,180,212		4,180,212	5
		-15,360,543		-15,360,543	6
6,333,845		161,193,067		161,193,067	7
		11,447,797		11,447,797	8
		-400		-400	9
		-2,281		-2,281	10
		-6,795		-6,795	11
-97		-6,615		-6,615	12
		-11,037		-11,037	13
-152		-4,279		-4,279	14
4,962,057	188,464,398	127,747,888	-61,481,776	254,730,510	
6,911,325	-1,817,184	189,628,634	0	187,811,450	
11,873,382	**186,647,214**	**317,376,522**	**-61,481,776**	**442,541,960**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SALES FOR RESALE (Account 447) (Continued)

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10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		141		141	1
-30		-5,112		-5,112	2
5		-2,054		-2,054	3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
4,962,057	188,464,398	127,747,888	-61,481,776	254,730,510	
6,911,325	-1,817,184	189,628,634	0	187,811,450	
11,873,382	**186,647,214**	**317,376,522**	**-61,481,776**	**442,541,960**	

Schedule Page: 310 Line No.: 1 Column: c

FERC Electric Tariff, First Revised Volume No. 5.

Schedule Page: 310 Line No.: 1 Column: k

Margins for Off System Sales (OSS) reported in I&M's generation formula rates are included in the total revenue amount. The margins are specifically identified in the ledger as a subset of the accounts that make up these OSS revenues.

Schedule Page: 310 Line No.: 10 Column: j

PJM transmission expenses related to wholesale customers.

Schedule Page: 310.3 Line No.: 3 Column: a

An affiliated company.

Schedule Page: 310.3 Line No.: 3 Column: c

The PUCO (Public Utilities Commission Ohio) ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning June 2015. APCo, KPCo, I&M and WPCo participated in the auction process and were awarded tranches of OPCo's SSO load.

Schedule Page: 310.3 Line No.: 4 Column: a

Per the IURC's order in Cause No. 44422 CSR 2, I&M tracks the level of capacity equalization settlement receipts or purchases compared to the level basic rates.

Schedule Page: 310.3 Line No.: 5 Column: a

Per the IURC's order in Cause No. 43774 PJM, I&M tracks the level of certain costs and revenues related to I&M's membership in PJM compared to the level in base rates.

Schedule Page: 310.3 Line No.: 6 Column: a

Per the IURC's order in Cause No. 43755 OSS, I&M shares off system sales margins above or below the level embedded in base rates down to $0.

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)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	4,116,795	4,574,709
5	(501) Fuel	137,375,658	152,641,822
6	(502) Steam Expenses	15,350,914	18,049,586
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,873,898	1,501,927
10	(506) Miscellaneous Steam Power Expenses	3,268,991	3,683,257
11	(507) Rents	70,159,078	70,150,198
12	(509) Allowances	1,038,606	1,693,088
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	233,183,940	252,294,587
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,286,011	2,426,052
16	(511) Maintenance of Structures	1,358,884	1,804,745
17	(512) Maintenance of Boiler Plant	8,411,145	6,313,331
18	(513) Maintenance of Electric Plant	2,594,303	1,550,329
19	(514) Maintenance of Miscellaneous Steam Plant	1,149,705	1,082,728
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	15,800,048	13,177,185
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	248,983,988	265,471,772
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	17,374,231	22,645,947
25	(518) Fuel	132,994,595	130,947,058
26	(519) Coolants and Water	8,370,744	7,094,337
27	(520) Steam Expenses	15,684,414	12,182,949
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	4,361,456	3,806,924
31	(524) Miscellaneous Nuclear Power Expenses	67,639,472	75,590,108
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	246,424,912	252,267,323
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	11,072,533	10,794,683
36	(529) Maintenance of Structures	3,758,221	4,584,924
37	(530) Maintenance of Reactor Plant Equipment	76,952,653	82,456,480
38	(531) Maintenance of Electric Plant	19,227,738	15,423,728
39	(532) Maintenance of Miscellaneous Nuclear Plant	19,707,637	17,579,319
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	130,718,782	130,839,134
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	377,143,694	383,106,457
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	473,685	464,520
45	(536) Water for Power		
46	(537) Hydraulic Expenses	117,119	132,551
47	(538) Electric Expenses	1,319	1,362
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,182,397	1,169,113
49	(540) Rents		1,098
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	1,774,520	1,768,644
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	187,530	199,078
54	(542) Maintenance of Structures	787,318	527,961
55	(543) Maintenance of Reservoirs, Dams, and Waterways	871,492	503,011
56	(544) Maintenance of Electric Plant	407,255	551,845
57	(545) Maintenance of Miscellaneous Hydraulic Plant	105,568	32,691
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	2,359,163	1,814,586
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	4,133,683	3,583,230

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	21,314	38,510
63	(547) Fuel		
64	(548) Generation Expenses	6	7
65	(549) Miscellaneous Other Power Generation Expenses	483,704	129,613
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	505,024	168,130
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant	-232	-38
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	-232	-38
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	504,792	168,092
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	394,347,396	454,568,469
77	(556) System Control and Load Dispatching	2,114,994	2,209,276
78	(557) Other Expenses	3,970,176	4,328,792
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	400,432,566	461,106,537
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,031,198,723	1,113,436,088
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	4,818,719	5,260,791
84			
85	(561.1) Load Dispatch-Reliability	5,055	26,388
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	444,496	1,721,731
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	4,522,359	4,500,443
89	(561.5) Reliability, Planning and Standards Development	119,595	175,090
90	(561.6) Transmission Service Studies	9	
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	1,414,671	1,158,668
93	(562) Station Expenses	473,729	655,393
94	(563) Overhead Lines Expenses	268,878	374,444
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	117,445,782	67,583,508
97	(566) Miscellaneous Transmission Expenses	1,766,992	4,299,540
98	(567) Rents	46,466	20,486
99	TOTAL Operation (Enter Total of lines 83 thru 98)	131,326,751	85,776,482
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	82,744	123,033
102	(569) Maintenance of Structures	50,081	30,221
103	(569.1) Maintenance of Computer Hardware	29,578	92,588
104	(569.2) Maintenance of Computer Software	484,035	1,197,381
105	(569.3) Maintenance of Communication Equipment	54,384	167,252
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,963,607	3,030,065
108	(571) Maintenance of Overhead Lines	6,776,955	7,495,953
109	(572) Maintenance of Underground Lines	2,417	126
110	(573) Maintenance of Miscellaneous Transmission Plant	109,862	405,222
111	TOTAL Maintenance (Total of lines 101 thru 110)	9,553,663	12,541,841
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	140,880,414	98,318,323

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
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	4,948,588	4,006,728
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	4,948,588	4,006,728
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 Op Expns (Total 123 and 130)	4,948,588	4,006,728
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	3,727,629	2,355,961
135	(581) Load Dispatching	982,245	1,213,588
136	(582) Station Expenses	678,365	798,600
137	(583) Overhead Line Expenses	1,022,924	3,577,692
138	(584) Underground Line Expenses	1,769,488	2,159,910
139	(585) Street Lighting and Signal System Expenses	109,862	98,367
140	(586) Meter Expenses	2,484,258	2,374,856
141	(587) Customer Installations Expenses	392,812	544,396
142	(588) Miscellaneous Expenses	13,323,599	15,622,481
143	(589) Rents	1,669,824	1,624,528
144	TOTAL Operation (Enter Total of lines 134 thru 143)	26,161,006	30,370,379
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	83,251	99,991
147	(591) Maintenance of Structures	42,016	88,979
148	(592) Maintenance of Station Equipment	1,424,578	1,759,347
149	(593) Maintenance of Overhead Lines	35,829,313	31,047,350
150	(594) Maintenance of Underground Lines	2,557,349	3,065,858
151	(595) Maintenance of Line Transformers	136,349	129,373
152	(596) Maintenance of Street Lighting and Signal Systems	318,338	280,976
153	(597) Maintenance of Meters	232,095	231,192
154	(598) Maintenance of Miscellaneous Distribution Plant	455,116	597,416
155	TOTAL Maintenance (Total of lines 146 thru 154)	41,078,405	37,300,482
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	67,239,411	67,670,861
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,132,839	1,134,950
160	(902) Meter Reading Expenses	867,290	834,957
161	(903) Customer Records and Collection Expenses	12,792,694	13,361,331
162	(904) Uncollectible Accounts	165,772	14,875
163	(905) Miscellaneous Customer Accounts Expenses	65,601	52,992
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	15,024,196	15,399,105

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	931,246	857,822
168	(908) Customer Assistance Expenses	24,313,371	21,056,488
169	(909) Informational and Instructional Expenses		7,100
170	(910) Miscellaneous Customer Service and Informational Expenses	139,435	7,712
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	25,384,052	21,929,122
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	1,290	385
175	(912) Demonstrating and Selling Expenses	208,524	63,686
176	(913) Advertising Expenses	1,354	1,540
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	211,168	65,611
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	33,826,147	34,496,971
182	(921) Office Supplies and Expenses	3,198,866	3,726,306
183	(Less) (922) Administrative Expenses Transferred-Credit	3,482,860	3,599,256
184	(923) Outside Services Employed	7,626,203	8,646,691
185	(924) Property Insurance	4,235,382	3,652,909
186	(925) Injuries and Damages	6,334,185	6,056,072
187	(926) Employee Pensions and Benefits	26,450,155	27,427,503
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	13,763,059	14,161,551
190	(929) (Less) Duplicate Charges-Cr.	946,508	762,039
191	(930.1) General Advertising Expenses	480,267	490,058
192	(930.2) Miscellaneous General Expenses	4,505,198	4,693,733
193	(931) Rents	2,754,974	5,740,940
194	TOTAL Operation (Enter Total of lines 181 thru 193)	98,745,068	104,731,439
195	Maintenance		
196	(935) Maintenance of General Plant	8,885,926	9,966,801
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	107,630,994	114,698,240
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,392,517,546	1,435,524,078

Name of Respondent Indiana Michigan Power Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Schedule Page: 320 Line No.: 5 Column: b

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.

Schedule Page: 320 Line No.: 25 Column: b

The portion of account 518 that is excluded from the nuclear fuel costs in I&M's generation formula rate is identified by a query of the general ledger.

Schedule Page: 320 Line No.: 31 Column: b

The portion of account 524 representing ARO expenses that are excluded from non-fuel generation O&M in I&M's 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.

Schedule Page: 320 Line No.: 93 Column: b

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 multiplied by the balance in O&M accounts 562, 569 & 570.

Schedule Page: 320 Line No.: 103 Column: b

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.

Schedule Page: 320 Line No.: 148 Column: b

Account 592.2 contains $388 for maintenance of energy storage equipment

Schedule Page: 320 Line No.: 148 Column: c

Account 592.2 contains $2,313 for maintenance of energy storage equipment

Schedule Page: 320 Line No.: 185 Column: b

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) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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.

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)
1	AEP GENERATING COMPANY	RQ	AEG 1			
2	CITY OF WINCHESTER, IN	OS				
3	FOWLER RIDGE II WIND FARM LLC	OS				
4	FOWLER RIDGE WIND FARM LLC	OS				
5	FRENCH PAPER	OS				
6	FT. WAYNE ELECTRIC JATC	OS				
7	HEADWATERS WIND FARM LLC	OS				
8	ICE TRADE VAULT LLC	OS				
9	MIZUHO SECURITIES USA INC	OS				
10	OVEC POWER SCHEDULING	OS				
11	OVER/UNDER PJM EXP TRACKER	OS				
12	PJM INTERCONNECTION	OS				
13	RANDOLPH SCHOOLS	OS				
14	WILDCAT WIND FARM	OS				
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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.

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)
1	WILLIAM E RICHTER	OS				
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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. Report in columns (h) and (i) 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 (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) 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 column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
3,823,206			127,733,065	96,166,427		223,899,492	1
				118,742		118,742	2
124,869				10,868,939		10,868,939	3
208,368				13,647,550		13,647,550	4
1,131				33,583		33,583	5
1				29		29	6
724,311				31,568,522		31,568,522	7
				12,600		12,600	8
				14,400		14,400	9
937,620			26,138,944	24,381,550		50,520,494	10
				-48,010,285		-48,010,285	11
2,270,707				94,239,229		94,239,229	12
				44,475		44,475	13
234,960				17,389,534		17,389,534	14
8,325,176			153,872,009	240,475,387		394,347,396	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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. Report in columns (h) and (i) 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 (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) 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 column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3				92		92	1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
8,325,176			153,872,009	240,475,387		394,347,396	

Schedule Page: 326 Line No.: 1 Column: a

Affiliated Company

Schedule Page: 326 Line No.: 11 Column: a

Per the IURC's Order in Cause No. 43774, 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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.

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 Classifi-cation (d)
1	PJM Network Integ Trans Rev Whlsl	Various	Various	FNO
2	PJM Network Integ Trans Serv	Various	Various	FNO
3	PJM Trans Enhancement Rev	Various	Various	FNO
4	PJM Trans Enhancement Rev Whlsle	Various	Various	FNO
5	PJM Trans Enhancement Rev - Affil	Various	Various	FNS
6	PJM Network Integ Rev - Affil	Various	Various	FNS
7	PJM Point to Point Trans Serv	Various	Various	LFP
8	PJM Trans Owner Admin Revenue	Various	Various	OLF
9	PJM Trans Owner Serv Rev Whlsle	Various	Various	OLF
10	PJM Power Factor Credits Rev Whlsle	Various	Various	OS
11	PJM Trans Distribution & Meter	Various	Various	OS
12	RTO Formation Costs Recovery	Various	Various	OS
13	SECA Transmission Rev	Various	Various	OS
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

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.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation 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)	Line No.
PJM OATT	Various	Various				1
PJM OATT	Various	Various				2
PJM OATT	Various	Various				3
PJM OATT	Various	Various				4
PJM OATT	Various	Various				5
PJM OATT	Various	Various				6
PJM OATT	Various	Various				7
PJM OATT	Various	Various				8
PJM OATT	Various	Various				9
PJM OATT	Various	Various				10
PJM OATT	Various	Various				11
PJM OATT	Various	Various				12
PJM OATT	Various	Various				13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**0**	**0**	

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

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 (11011) 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.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
6,569,446			6,569,446	1
13,511,271			13,511,271	2
4,014,021			4,014,021	3
168,366			168,366	4
14,635			14,635	5
-28,477			-28,477	6
1,341,581			1,341,581	7
	198,831		198,831	8
	67,523		67,523	9
		106,702	106,702	10
		512,182	512,182	11
125,170			125,170	12
		262,500	262,500	13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
25,716,013	**266,354**	**881,384**	**26,863,751**	

Schedule Page: 328 Line No.: 1 Column: e

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.

Schedule Page: 328 Line No.: 10 Column: m

Per Proforma ILDSO (Interconnection and Local Delivery Service Agreement) AEP Tariff 3rd Revised Volume No. 6

Schedule Page: 328 Line No.: 11 Column: m

Per Proforma ILDSA AEP Tarifff 3rd Revised Volume 6.

Schedule Page: 328 Line No.: 13 Column: m

Settlement of Seams Elimination Cost Allocation (SECA) revenue, which was subject to refund. Amount represents reserves that exceeded settlement.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
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37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

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: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-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					30,525,846	30,525,846
2	PJM NITS	OS					86,118,702	86,118,702
3	PJM-Trans Owner	OS					801,027	801,027
4	Other	OS					207	207
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						117,445,782	117,445,782

Schedule Page: 332 Line No.: 1 Column: b

Transmission Enhancement Charges and Credits (PJM OATT Schedule 12)

Schedule Page: 332 Line No.: 2 Column: b

Network Integration Transmission Service Charges - NITS (PJM OATT Schedule H)

Schedule Page: 332 Line No.: 3 Column: b

Transmission Owner Service (PJM OATT Tariff Sixth Revised Volume No. 1)

Schedule Page: 332 Line No.: 4 Column: b

Midwest Independent Transmission System Operator (MISO) Membership/Participant Dues.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	3,287,617
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Associated Business Development	895,220
7	American Electric Power Service Corp Billings	273,298
8	Corporate Money Pool Allocations	59,871
9	Corporate Legal and Financing	5,590
10	Corporate Contributions and Memberships	103,093
11	Intercompany Billings	-122,225
12	Minor Items	2,734
13		
14		
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46	TOTAL	4,505,198

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

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 8 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 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			20,506,926		20,506,926
2	Steam Production Plant	33,019,760	197,208	8,375,778		41,592,746
3	Nuclear Production Plant	58,478,223	1,512,626			59,990,849
4	Hydraulic Production Plant-Conventional	1,358,793	12,488			1,371,281
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	1,939,357				1,939,357
7	Transmission Plant	25,028,104				25,028,104
8	Distribution Plant	55,630,522				55,630,522
9	Regional Transmission and Market Operation					
10	General Plant	3,771,019	1,171	816,282		4,588,472
11	Common Plant-Electric					
12	TOTAL	179,225,778	1,723,493	29,698,986		210,648,257

B. Basis for Amortization Charges

Section A, Line 1, Column D represents amortization of franchises over the life of the franchise, amortization 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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	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	97,400					
14	311 - Rockport U2	4,059					
15	311 - Rkpt DSI U1	2,904					
16	311 - Rkpt DSI U2	503					
17	312 - Rockport ACI	11,813					
18	312 - Rockport U1	405,892					
19	312 - Rockport U2	19,193					
20	312 - Rockport U1 -SCR	132,768					
21	312 - Rkpt DSI U1	51,664					
22	312 - Rkpt DSI U1 - Pre	24,807					
23	312 - Rkpt DSI U2	51,144					
24	314 - Rockport U1	95,120					
25	314 - Rockport U2	867					
26	315 - Rockport U1	58,852					
27	315 - Rockport U2	2,080					
28	316 - Rockport U1	16,090					
29	316 - Rockport U2	6,784					
30	TOTAL STEAM	981,940					
31							
32	NUCLEAR						
33	321 - Cook U1	78,654					
34	321 - Cook U2	346,133					
35	322 - Cook U1	656,984					
36	322 - Cook U2	833,470					
37	323 - Cook U1	271,235					
38	323 - Cook U2	383,898					
39	324 - Cook U1	104,129					
40	324 - Cook U2	147,180					
41	325 - Cook U1	34,024					
42	325 - Cook U2	216,107					
43	TOTAL NUCLEAR	3,071,814					
44							
45	HYDRO						
46	331 - Berrien Springs	561					
47	331 - Buchanan	596					
48	331 - Constantine	307					
49	331 - Crew Service Cent	417					
50	331 - Elkhart	870					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	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	331 - Mottville	497					
13	331 - Twin Branch	551					
14	332 - Berrien Springs	5,109					
15	332 - Buchanan	4,532					
16	332 - Constantine	1,219					
17	332 - Elkhart	4,089					
18	332 - Mottville	2,182					
19	332 - Twin Branch	5,093					
20	333 - Berrien Springs	7,179					
21	333 - Buchanan	1,296					
22	333 - Constantine	737					
23	333 - Elkhart	607					
24	333 - Mottville	596					
25	333 - Twin Branch	5,991					
26	334 - Berrien Springs	1,213					
27	334 - Buchanan	1,024					
28	334 - Constantine	463					
29	334 - Elkhart	461					
30	334 - Mottville	615					
31	334 - Twin Branch	1,636					
32	335 - Berrien Springs	790					
33	335 - Buchanan	265					
34	335 - Constantine	309					
35	335 - Crew Service Cent	127					
36	335 - Elkhart	184					
37	335 - Mottville	383					
38	335 - Twin Branch	585					
39	336 - Mottville	1					
40	TOTAL HYDRO	50,485					
41							
42	OTHER GENERATION						
43	341 - Olive Solar	377					
44	341 - Watervliet Solar	358					
45	344 - Deer Creek Solar	6,127					
46	344 - Olive Solar	11,185					
47	344 - Twin Branch Sol	6,955					
48	344 - Watervliet Solar	11,113					
49	345 - Olive Solar	269					
50	346 - Olive Solar	215					

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	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	346 - Watervliet Solar	341					
13	TOTAL OTHER	36,940					
14							
15	TRANSMISSION						
16	350 (Rights)	59,705					
17	352	26,754					
18	352 - City Lights Acq	19					
19	353	709,647					
20	353 - City Lights Acq	294					
21	353.16	71					
22	354	232,730					
23	355	174,413					
24	356	266,300					
25	356.16	1					
26	357	1,594					
27	357 - City Lights Acq	719					
28	358	5,968					
29	358 - City Lights Acq	234					
30	359	347					
31	TOTAL TRANSMISSION	1,478,796					
32							
33	DISTRIBUTION						
34	360 (Rights) - IN	9,069					
35	360 (Rights) - MI	5,095					
36	361 - IN	14,759					
37	361 - MI	4,157					
38	361 - City Lights Acq	312					
39	362 - IN	235,904					
40	362 - MI	54,025					
41	362.16 - IN	33					
42	362 - City Lights Acq	2,433					
43	363 - IN	5,608					
44	364 - IN	205,455					
45	364 - MI	65,659					
46	364 - City Lights Acq	534					
47	365 - IN	321,054					
48	365 - MI	120,817					
49	365 - City Lights Acq	488					
50	366 - IN	86,333					

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2017/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	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	366 - MI	10,200					
13	366 - City Lights Acq	2,218					
14	367 - IN	208,650					
15	367 - MI	34,785					
16	367 - City Lights Acq	1,342					
17	368 - IN	270,775					
18	368 - MI	47,597					
19	368 - City Lights Acq	66					
20	369 - IN	145,486					
21	369 - MI	30,302					
22	369 - City Lights Acq	2,392					
23	370 - IN	76,264					
24	370 - MI	16,961					
25	370.16	3,715					
26	371 - IN	18,874					
27	371 - MI	8,117					
28	371 - City Lights Acq	9					
29	373 - IN	16,047					
30	373 - MI	4,913					
31	TOTAL DISTRIBUTION	2,030,448					
32							
33	GENERAL PLANT						
34	390	39,694					
35	391	7,057					
36	393	718					
37	394	14,475					
38	395	367					
39	396	544					
40	397	44,983					
41	397.16	335					
42	398	10,300					
43	TOTAL GENERAL PLANT	118,473					
44							
45	DEPRECIABLE SUM	7,768,896					
46							
47							
48							
49							
50							

Schedule Page: 336 Line No.: 7 Column: b

Generation Step-Up Units (GSU's) depreciation expenses included in I&M's generation formula rates are a subset of transmission depreciation and identified by a query of the plant accounting system.

Schedule Page: 336.3 Line No.: 45 Column: b

The Depreciable plant base is the November 30, 2017 total company deprciable plant.

City Light Acq distribution accounts represent the Fort Wayne City Light Acquisition depreciated over 15 years (until February 2025) per agreement filed with the Indiana Utility Regulatory Commission on June 6, 2011 Cause No. 43980.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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.

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 Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Nuclear Regulatory Commission				
2	- Inspection and Licensing Fees	2,022,320		2,022,320	
3	- Annual Fees	8,812,000		8,812,000	
4					
5					
6	Hydro License Fee		38,178	38,178	
7					
8	Current Indiana Rate Case		1,571,820	1,571,820	600,384
9					
10	Current Michigan Rate Case		1,072,709	1,072,709	63,524
11					
12	FERC Filing-Behalf of PJM East Reg Companies		5,807	5,807	
13					
14	Depreciation Rate Update Filing		54,376	54,376	
15					
16	Integrated Resource Plan Filing		75,255	75,255	
17					
18	FERC 205/206 Filings		40,892	40,892	
19					
20	Minor Items < $25,000		69,702	69,702	
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	TOTAL	10,834,320	2,928,739	13,763,059	663,908

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

REGULATORY COMMISSION EXPENSES (Continued)

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 column (f), (g), and (h) expenses incurred during 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							
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)	Line No.
							1
	928	2,022,320					2
	928	8,812,000					3
							4
							5
	928	38,178					6
							7
	928	1,571,820	486,305			1,086,689	8
							9
	928	1,072,709	476,748			540,272	10
							11
	928	5,807					12
							13
	928	54,376					14
							15
	928	75,255					16
							17
	928	40,892					18
							19
	928	69,702					20
							21
							22
							23
							24
							25
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		13,763,059	963,053			1,626,961	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 & 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 & 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 & 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 & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A(1)b: Generation: Fossil Fuel Steam	3 items < $50,000
2		1 item <$50,000
3		Generation Asset Management
4	A(1)d: Generation: Nuclear	1 item <$50,000
5	A(1)e: Generation: Unconventional	1 item <$50,000
6		1 item <$50,000
7	A(2): Transmission	2 items <$50,000
8	A(3): Distribution	2 items <$50,000
9	A(5): Environment (other than equipment)	Industrial Advisory Committee - Southern Co.
10		2 items <$50,000
11	A(6): Other	2 items <$50,000
12		2 items <$50,000
13		2 items <$50,000
14		3 items <$50,000
15	A(6)f: Other: Metering	1 item <$50,000
16	A(6)g: Research-General	1 item <$50,000
17		1 item <$50,000
18	A(7) TOTAL COSTS INCURRED INTERNALLY	
19	B: Electric R&D External	
20		1 item <$50,000
21		1 item <$50,000
22		3 items <$50,000
23		4 items <$50,000
24	B(1): Research Support to Electric Research	EPRI Environmental Science
25		EPRI Environmental Controls
26		EPRI Research Portfolio
27		EPRI Research Portfolio
28		EPRI Research Portfolio
29		EPRI Nuclear Annual Research
30		IT - EPRI Annual Research Port
31		IT - EPRI Annual Research Port
32		IT - EPRI Annual Research Port
33		IT - EPRI Annual Research Port
34		11 items <$50,000
35		3 items <$50,000
36		11 items <$50,000
37		3 items<$50,000
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 & 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 & 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 & 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 & D Performed Externally:
(1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	(B4): Steam Power	4 items <$50,000
2		1 item <$50,000
3	B(5) TOTAL COSTS INCURRED EXTERNALLY	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(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 & 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 & 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 & 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 &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.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
5,849		506	5,849		1
9,350		524	9,350		2
68,318		506	68,318		3
337		524	337		4
676		506	676		5
2		588	2		6
17,228		566	17,228		7
33,687		588	33,687		8
92,644		506	92,644		9
1,187		506	1,187		10
3,320		506	3,320		11
5,348		524	5,348		12
2,653		566	2,653		13
5,317		588	5,317		14
1,656		588	1,656		15
314		566	314		16
501		588	501		17
248,387			248,387		18
					19
	3,294	506	3,294		20
	10,621	524	10,621		21
	8,250	566	8,250		22
	20,566	588	20,566		23
	428,205	506	428,205		24
	122,765	506	122,765		25
	121,490	506	121,490		26
	196,967	566	196,967		27
	44,869	588	44,869		28
	1,444,093	524	1,444,093		29
	4,816	506	4,816		30
	51,276	524	51,276		31
	4,354	566	4,354		32
	24,991	588	24,991		33
	33,473	506	33,473		34
	7,690	524	7,690		35
	350	566	350		36
	2,013	588	2,013		37
					38

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(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 & 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 & 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 & 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 &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.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
	20,019	506	20,019		1
	7,615	566	7,615		2
	2,557,717		2,557,717		3
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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	81,872,249		
4	Transmission	1,702,522		
5	Regional Market			
6	Distribution	7,804,527		
7	Customer Accounts	3,320,710		
8	Customer Service and Informational	3,385,757		
9	Sales	1,966		
10	Administrative and General	3,724,316		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	101,812,047		
12	Maintenance			
13	Production	54,053,017		
14	Transmission	2,262,550		
15	Regional Market			
16	Distribution	8,956,800		
17	Administrative and General	1,436,753		
18	TOTAL Maintenance (Total of lines 13 thru 17)	66,709,120		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	135,925,266		
21	Transmission (Enter Total of lines 4 and 14)	3,965,072		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	16,761,327		
24	Customer Accounts (Transcribe from line 7)	3,320,710		
25	Customer Service and Informational (Transcribe from line 8)	3,385,757		
26	Sales (Transcribe from line 9)	1,966		
27	Administrative and General (Enter Total of lines 10 and 17)	5,161,069		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	168,521,167	8,087,753	176,608,920
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			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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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)	168,521,167	8,087,753	176,608,920
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	44,304,162	2,126,268	46,430,430
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	44,304,162	2,126,268	46,430,430
72	Plant Removal (By Utility Departments)			
73	Electric Plant	6,189,886	297,068	6,486,954
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	6,189,886	297,068	6,486,954
77	Other Accounts (Specify, provide details in footnote):			
78	120 - Nuclear Fuel in Proc of Refinement	317,104		317,104
79	121 - Nonutility Property WIP	277		277
80	152 - Fuel Stock Undistributed	2,459,737		2,459,737
81	163 - Stores Expense Undistributed	7,271,071	-7,271,071	
82	183 - Prelim Survey	28,173	-28,173	
83	184 - Clearing Accounts	3,211,845	-3,211,845	
84	185 - ODD Temporary Facilities	91,784		91,784
85	186 - Misc Deferred Debits	1,542,890		1,542,890
86	188 - Research & Development	-770		-770
87	228 - RAD Waste Accrual	45,372		45,372
88	417 - Misc Expense	20,433,628		20,433,628
89	426 - Political Activities	63,660		63,660
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	35,464,771	-10,511,089	24,953,682
96	TOTAL SALARIES AND WAGES	254,479,986		254,479,986

Schedule Page: 354 Line No.: 28 Column: b

The labor charges from AEP Service Corporation included in the development of the I&M generation formula rate payroll allocator are derived from a query of the general ledger.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 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 order of the Commission or other authorization.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)				66,917,888
3	Net Sales (Account 447)				(197,083,313)
4	Transmission Rights				(13,526,154)
5	Ancillary Services				11,140,305
6	Other Items (list separately)				
7	Congestion				35,580,353
8	Operating Reserves				972,008
9	Transmission Purchase Expense				59,178,947
10	Transmission Losses				24,019,504
11	Meter Corrections				1,231,241
12	Inadvertent				214,032
13	Capacity Credits				
14	Miscellaneous				
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46	TOTAL				(11,355,189)

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) 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)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch						
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)						

Schedule Page: 398   Line No.: 1   Column: b

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.

NAME OF SYSTEM:

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)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports 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)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)	17,946,571
3	Steam	5,461,727			
4	Nuclear	17,592,001	23	Requirements Sales for Resale (See instruction 4, page 311.)	4,962,057
5	Hydro-Conventional	107,362			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	6,911,325
7	Other	24,219			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	42
9	Net Generation (Enter Total of lines 3 through 8)	23,185,309	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	8,325,176	27	Total Energy Losses	1,690,490
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	31,510,485
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	31,510,485			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	2,882,841	692,087	3,696	5	900
30	February	2,668,366	786,163	3,516	10	1100
31	March	2,571,393	515,896	3,508	15	800
32	April	2,242,745	418,182	3,149	6	1100
33	May	2,628,808	741,793	3,617	18	1500
34	June	2,661,633	581,139	4,163	12	1700
35	July	3,072,432	817,811	4,230	19	1700
36	August	2,842,822	652,779	4,048	21	1400
37	September	2,245,724	276,239	4,055	26	1600
38	October	2,244,672	322,861	3,325	4	1400
39	November	2,056,027	67,667	3,309	20	900
40	December	3,393,022	1,216,052	3,516	14	800
41	TOTAL	31,510,485	7,088,669			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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 Mct. 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.

Line No.	Item (a)	Plant Name: *ROCKPORT UNIT 1 I&M* (b)	Plant Name: *ROCKPORT UNIT 2 I&M* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional
3	Year Originally Constructed	1984	1989
4	Year Last Unit was Installed	1984	1989
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	660.00	650.00
6	Net Peak Demand on Plant - MW (60 minutes)	670	657
7	Plant Hours Connected to Load	4731	6541
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	660	650
10	When Limited by Condenser Water	658	650
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	2350609000	3111118000
13	Cost of Plant: Land and Land Rights	6477506	67771
14	Structures and Improvements	98203241	7210912
15	Equipment Costs	788068929	178162941
16	Asset Retirement Costs	6675713	6896104
17	Total Cost	899425389	192337728
18	Cost per KW of Installed Capacity (line 17/5) Including	1362.7657	295.9042
19	Production Expenses: Oper, Supv, & Engr	1952185	1901936
20	Fuel	58918621	78457037
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	6616241	8734835
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	1017772	856146
26	Misc Steam (or Nuclear) Power Expenses	1592271	1569525
27	Rents	-5	70147245
28	Allowances	519303	519303
29	Maintenance Supervision and Engineering	1098528	1080938
30	Maintenance of Structures	708113	247838
31	Maintenance of Boiler (or reactor) Plant	5995470	2417235
32	Maintenance of Electric Plant	1797964	575926
33	Maintenance of Misc Steam (or Nuclear) Plant	638211	511724
34	Total Production Expenses	80854674	167019688
35	Expenses per Net KWh	0.0344	0.0537

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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 Mct. 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.

Line No.	Item (a)	Plant Name: (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	0	0
15	Equipment Costs	0	0
16	Asset Retirement Costs	0	0
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0	0
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	0	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	0	0
35	Expenses per Net KWh	0.0000	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: *ROCKPORT TOTAL I&M* (d)			Plant Name: *ROCKPORT TOTAL PLANT* (e)			Plant Name: *Donald C Cook Plant* (f)			Line No.
Steam			Steam			Nuclear			1
Conventional			Conventional			Conventional			2
1984			1984			1975			3
1989			1989			1978			4
1310.00			2620.00			2285.00			5
1315			2630			2318			6
7685			7685			8760			7
0			0			0			8
1310			2620			2278			9
1308			2615			2153			10
0			246			1171			11
5461727000			10923454000			17592001000			12
6545277			13061228			1879588			13
105414153			212576149			426490248			14
966231870			1923586779			2670399265			15
13571817			27125552			135680600			16
1091763117			2176349708			3234449701			17
833.4070			830.6678			1415.5141			18
3854121			7758519			17374299			19
137375658			274756270			132994595			20
0			0			8370744			21
15351076			33675492			15683843			22
0			0			0			23
0			0			0			24
1873918			3747849			4361456			25
3161796			6335766			67619805			26
70147240			138430266			0			27
1038606			1038606			0			28
2179466			4321015			11057364			29
955951			1911919			3758221			30
8412705			16825731			76954201			31
2373890			4747869			19204401			32
1149935			2299897			19707694			33
247874362			495849199			377086623			34
0.0454			0.0454			0.0214			35
Coal	Oil		Coal	Oil		Nuclear			36
Tons	Barrels		Tons	Barrels					37
3001779	23273	0	6003558	46545	0	0	0	0	38
8897	136974	0	8897	136974	0	0	0	0	39
43.927	73.296	0.000	43.927	73.296	0.000	0.000	0.000	0.000	40
45.230	69.004	0.000	45.231	69.004	0.000	0.000	0.000	0.000	41
2.542	11.995	0.000	2.542	11.995	0.000	0.740	0.000	0.000	42
0.025	0.000	0.000	0.025	0.000	0.000	0.008	0.000	0.000	43
9953.000	0.000	0.000	9953.000	0.000	0.000	10212.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) X An Original (2) __ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 403   Line No.: -1   Column: e

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. 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
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)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

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 the 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."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
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)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
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	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
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)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

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.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydro electric					
2	Berrien Springs	1908	7.20	5.9	37,271	15,033,135
3	Buchanan	1919	4.10	2.7	15,711	7,779,143
4	Constantine	1921	1.20	1.0	4,652	3,152,448
5	Elkhart	1913	3.44	3.0	17,008	6,659,473
6	Mottville	1923	1.68	1.5	7,211	4,361,006
7	Twin Branch	1904	4.80	4.3	25,509	13,977,661
8						
9						
10						
11	Solar electric					
12	Deer Creek	2015	2.50	2.6	3,801	6,139,152
13	Olive	2016	5.00	5.5	8,456	12,062,064
14	Twin Branch	2016	2.60	2.8	4,236	6,958,803
15	Watervliet	2016	4.60	4.9	7,726	11,963,255
16						
17						
18						
19						
20						
21						
22						
23						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 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.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
2,087,935	517,063		241,034			2
1,897,352	295,928		284,587			3
2,627,040	139,612		97,195			4
1,935,893	287,460		264,160			5
2,595,837	164,425		685,256			6
2,912,013	370,032		786,931			7
						8
						9
						10
						11
2,455,661	63,507		-39			12
2,412,413	193,955		-79			13
2,676,463	84,208		-41			14
2,600,708	163,354		-73			15
						16
						17
						18
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TRANSMISSION LINE STATISTICS

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6. 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.

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
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	STATE OF INDIANA							
2	6128 DUMONT	JEFFERSON	765.00	765.00	3	202.76		1
3	6128 DUMONT	JEFFERSON	765.00	765.00	3	0.24		
4	6136 DUMONT	WILTON CENTER	765.00	765.00	3	63.00		1
5	6141 DUMONT	MARYSVILLE	765.00	765.00	3	99.38		1
6	6215 D.C. COOK	DUMONT	765.00	765.00	3	20.00		1
7	6223 ROCKPORT	JEFFERSON	765.00	765.00	3	111.00		1
8	6224 ROCKPORT	SULLIVAN	765.00	765.00	3	97.00		1
9	6226 JEFFERSON	WEST	765.00	765.00				
10	6236 HANGING ROCK	JEFFERSON	765.00	765.00	3	1.00		1
11	0675 TANNERS CREEK	SORENSON	345.00	345.00	3	136.00		2
12	0676 SORENSON	EAST LIMA	345.00	345.00	3	29.68		1
13	0676 SORENSON	EAST LIMA	345.00	345.00	1	0.27		1
14	0677 BREED	DEQUINE EAST	345.00	345.00	3	187.78		2
15	0677 BREED	DEQUINE EAST	345.00	345.00	1	0.23		1
16	0677 BREED	DEQUINE EAST	345.00	345.00	1	0.07		2
17	0678 DEQUINE	OLIVE	345.00	345.00	3	90.70		2
18	0678 DEQUINE	OLIVE	345.00	345.00	1	0.50		2
19	0679 SORENSON	OLIVE	345.00	345.00	3	78.00		2
20	0680 OLIVE	GOODINGS GROVE	345.00	345.00	3	41.00		2
21	0683 DESOTO	JCT TOWER (MAR. CO)	345.00	345.00	3	53.00	6.00	1
22	0684 TANNERS CREEK	JUNCTION TOWER	345.00	345.00	3	80.00		1
23	0685 HANNA	JUNCTION TOWER	345.00	345.00	3	5.63		
24	0687 TANNERS CREEK	MIAMI FORT	345.00	345.00	3			2
25	0688 EUGENE	SIDNEY	345.00	345.00	1	0.20		1
26	0689 SORENSON-OLIVE	TWIN BRANCH	345.00	345.00	3	11.00		2
27	0690 BREED	CIPSCO	345.00	345.00	3	0.94		1
28	0690 BREED	CIPSCO	345.00	345.00	3	0.02		1
29	0691 BREED	PETERSBURG	345.00	345.00	3	0.70		1
30	0691 BREED	PETERSBURG	345.00	345.00	1	0.15		1
31	6118 ROBISON PARK	SORENSON-EAST LIMA	345.00	345.00	3	22.66		2
32	6118 ROBISON PARK	SORENSON-EAST LIMA	345.00	345.00	1	0.34		1
33	6119 COOK	OLIVE	345.00	345.00	3	4.00		2
34	6122 DUMONT	OLIVE	345.00	345.00	3	15.00		2
35	6122 DUMONT	OLIVE	345.00	345.00	1	0.10		1
36					TOTAL	3,923.33	127.09	248

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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.
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6. 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.

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
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	6123 DUMONT	TWIN BRANCH	345.00	345.00	3	17.00		2
2	6125 ROBISON PARK	EAST	345.00	345.00				
3	6133 DUMONT	BABCOCK	345.00	345.00	3	9.00		1
4	6145 TWIN BRANCH	COOK-ROB PARK JCT	345.00	345.00	3	6.00		2
5	6147 COOK	ROBISON PARK	345.00	345.00	3	67.41		2
6	6147 COOK	ROBISON PARK	345.00	345.00	1	0.41		
7	6148 JACKSON ROAD	SORENSON-OLIVE	345.00	345.00	3	4.00		2
8	6213 COOK-ROB-PARK JCT	ARGENTA	345.00	345.00	3	2.00		2
9	6237 JACKSON ROAD	WEST	345.00	345.00				
10	6240 TWIN BRANCH	SUBSTATION CORRIDOR	345.00	345.00				
11	6256 BREED	SULLIVAN	345.00	345.00	3	0.48		2
12	6256 BREED	SULLIVAN	345.00	345.00	3	0.75		1
13	6256 BREED	SULLIVAN	345.00	345.00	1	0.29		1
14	6259 COLLINGWOOD	SOUTH BUTLER	345.00	345.00	1	12.00		1
15	6232 GODMAN TAP		34.00	138.00				
16	0602 TWIN BRANCH	RIVERSIDE	138.00	138.00	3	6.00		2
17	0603 TWIN BRANCH	SOUTH BEND	138.00	138.00	3	5.00		1
18	0604 TWIN BRANCH	ROBISON PARK	138.00	138.00	3	54.60		2
19	0604 TWIN BRANCH	ROBISON PARK	138.00	138.00	1	0.28		2
20	0605 SOUTH BEND	MICHIGAN CITY	138.00	138.00	3			1
21	0606 ROBISON PARK	HAVILAND	138.00	138.00	3	12.01		2
22	0606 ROBISON PARK	HAVILAND	138.00	138.00	1	0.05		
23	0607 ROBISON PARK	DEER CREEK	138.00	138.00	3	34.19		2
24	0607 ROBISON PARK	DEER CREEK	138.00	138.00	1	0.20		2
25	0608 DEER CREEK	KOKOMO	138.00	138.00	3	1.56		1
26	0608 DEER CREEK	KOKOMO	138.00	138.00	3	5.96		1
27	0608 DEER CREEK	KOKOMO	138.00	138.00	1	0.17		1
28	0609 CONCORD TAP		138.00	138.00	3	4.00		2
29	0613 TWIN BRANCH	JACKSON ROAD	138.00	138.00	3	8.00		2
30	0614 LINCOLN TAP		138.00	138.00	3	4.00		2
31	0615 TWIN BRANCH	ROBISON PARK	138.00	138.00	3	65.83		1
32	0616 DEER CREEK	DELAWARE	138.00	138.00	3	24.15		2
33	0617 DELAWARE	MADISON	138.00	138.00	3	18.81		2
34	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	3,4	56.05		2
35	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	4	1.69		2
36					TOTAL	3,923.33	127.09	248

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	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	1	0.17		2
2	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	1	0.08		
3	0725 DELAWARE	TRENTON	138.00	138.00	3,4			
4	0619 MADISON	NEW CASTLE	138.00	138.00	3	6.00	1.00	1
5	0620 TANNERS CREEK	MADISON	138.00	138.00	3	82.00		2
6	0622 JACKSON ROAD	OLIVE	138.00	138.00	3	16.94	1.00	1
7	0623 MADISON	PENDLETON	138.00	138.00	2	5.00		1
8	0624 DRAGOON TAP		138.00	138.00	3	2.00		1
9	0625 TANNERS CREEK	COLLEGE CORNER	138.00	138.00	3	40.00		2
10	0626 COLLEGE CORNER	RANDOLPH	138.00	138.00	2	34.81		1
11	0626 COLLEGE CORNER	RANDOLPH	138.00	138.00	1	0.85		1
12	0626 COLLEGE CORNER	RANDOLPH	138.00	138.00	2	3.34		
13	0627 RANDOLPH	JAY	138.00	138.00	2	23.69		1
14	0627 RANDOLPH	JAY	138.00	138.00	1	0.32		
15	0628 MCKINLEY TAP		138.00	138.00	3	1.00		2
16	0629 JAY	LINCOLN	138.00	138.00	2	46.18		1
17	0629 JAY	LINCOLN	138.00	138.00	3	3.11		1
18	0630 NEW CARLISLE	MAPLE	138.00	138.00	2	1.00		1
19	6104 SORENSON	TWIN BRANCH	138.00	138.00	3	61.17		1
20	6104 SORENSON	TWIN BRANCH	138.00	138.00	1	0.31		1
21	6104 SORENSON	TWIN BRANCH	138.00	138.00	1	3.32		1
22	0632 SORENSON	DEVILS HOLLOW	138.00	138.00	3			
23	0634 DEER CREEK	MULLIN	138.00	138.00	2	15.00		1
24	0635 PENDLETON	MULLIN	138.00	138.00	2	14.57		1
25	0635 PENDLETON	MULLIN	138.00	138.00	3	0.40		1
26	0635 PENDLETON	MULLIN	138.00	138.00	1	0.63		1
27	0636 DEER CREEK	FISHER BODY	138.00	138.00	3	5.04		2
28	0637 TWIN BRANCH	EAST ELKHART	138.00	138.00	3	17.00	1.00	2
29	0638 GRANT	FISHER BODY	138.00	138.00	3		1.00	1
30	0639 ROBISON PARK	AUBURN	138.00	138.00	1			1
31	0641 DESOTO	MEDFORD	138.00	138.00	3	7.00		2
32	0642 OLIVE	HICKORY CREEK	138.00	138.00	3	2.99	2.00	1
33	0645 COREY TAP		138.00	138.00	2	4.00		1
34	0646 OLIVE	NEW CARLISLE	138.00	138.00	3	2.00		1
35	0647 OLIVE	SOUTH BEND	138.00	138.00	3	1.00	16.00	1
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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
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	0648 MEDFORD TAP		138.00	138.00	3	8.00		2
2	0723 SPY RUN STATION		138.00	138.00	4			1
3	6101 WESTINGHOUSE TAP		138.00	138.00	3	2.00		2
4	6102 MILAN TAP		138.00	138.00	3	6.00		2
5	6103 MILAN	GOODRICH	138.00	138.00	3	1.00		2
6	6105 DESOTO	JAY	138.00	138.00	2	10.31		1
7	6105 DESOTO	JAY	138.00	138.00	3	2.25		1
8	6106 DESOTO	DEER CREEK-DELAWARE	138.00	138.00	3	7.52		2
9	6106 DESOTO	DEER CREEK-DELAWARE	138.00	138.00	1	0.48		
10	6107 DARDEN TAP		138.00	138.00	2	1.00		1
11	6109 ROBISON PARK	RICHLAND	138.00	138.00	2	13.76		1
12	6109 ROBISON PARK	RICHLAND	138.00	138.00	1	0.05		
13	6109 ROBISON PARK	RICHLAND	138.00	138.00	3	4.49		
14	6110 WESTINGHOUSE	23RD STREET	138.00	138.00	3			2
15	6111 KANKAKEE	WEST SIDE	138.00	138.00	1	2.00		1
16	6113 INDUSTRIAL PARK		138.00	138.00	3	3.00		2
17	6114 OLIVE	MICHIGAN CITY	138.00	138.00	3	2.00	1.00	1
18	6115 HUMMEL CREEK	VAN BUREN	138.00	138.00	3	6.00		2
19	6130 HUMMEL CREEK	TOWER 70, GREENTOWN	138.00	138.00				
20	6116 SOUTH ELWOOD TAP		138.00	138.00	1	3.00		1
21	6117 PENDLETON	FALL CREEK	138.00	138.00	3	10.00		2
22	6121 ROBISON PARK	LINCOLN	138.00	138.00	3	7.84		1
23	6121 ROBISON PARK	LINCOLN	138.00	138.00	1	0.02		
24	6126 CONCORD	EAST ELKHART	138.00	138.00	3	11.00		1
25	6129 GREENTOWN-GRANT	HUMMEL CREEK	138.00	138.00	3	21.00		1
26	6131 INDUSTRIAL PARK	MC KINLEY	138.00	138.00	1	5.00		1
27	6132 CROSS STREET TAP	JUNCTION TOWER #88	138.00	138.00	1	4.00		1
28	6134 LINCOLN	ANTHONY	138.00	138.00	1	3.00		1
29	6135 WAYNEDALE TAP		138.00	138.00	3			2
30	6138 JACKSON ROAD	SOUTH SIDE	138.00	138.00	1	2.00		1
31	6142 ALBION	KENDALLVILLE	138.00	138.00	1	10.00		1
32	6150 SOUTHSIDE	SOUTH BEND	138.00	138.00	1	6.07		1
33	6219 DELCO BATTERY TAP		138.00	138.00	1	1.00		2
34	6220 FALL CREEK	MADISON-NEW CASTLE	138.00	138.00	3	1.00		2
35	6225 INDUSTRIAL PARK	SPY RUN	138.00	138.00	1	4.00		1
36					TOTAL	3,923.33	127.09	248

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	6266 WALLEN		138.00	138.00	1	0.22		1
2	6234 CABOT TAP/CR 4	EAST ELKHART	138.00	138.00	1	0.13		1
3	6238 SORENSON	MCKINLEYTOWER	138.00	138.00	3	3.04		2
4	6238 SORENSON	MCKINLEYTOWER	138.00	138.00	1	0.09		2
5	6241 KENDALLVILLE TAP	CITY OF AUBURN #5	138.00	138.00	1,2	14.00		1
6	6242 AUBURN	CITY OF AUBURN #5	138.00	138.00	1	2.00		1
7	6245 LAPORTE JCT	LIQUID CARBONICS	138.00	138.00	1	4.76		1
8	6245 LAPORTE JCT	LIQUID CARBONICS	138.00	138.00	1	0.23		
9	6246 LAPORTE JCT	AIRCO	138.00	138.00	1	0.72		1
10	6248 ELCONA TAP	CONC-DUN-E-ELK	138.00	138.00	1	2.00		1
11	6249 ALLEN	LINCOLN	138.00	138.00	3	4.90		2
12	6249 ALLEN	LINCOLN	138.00	138.00	1	0.09		2
13	6250 ALLEN	ADAMS/HILLCREST	138.00	138.00	3	4.92		2
14	6250 ALLEN	ADAMS/HILLCREST	138.00	138.00	1	0.07		2
15	6251 OLIVE	EDISON	138.00	138.00	3	1.00		2
16	6253 TRIER RD TAP		138.00	138.00	1			1
17	6258 KENZIE CREEK	TWIN BRANCH	138.00	138.00	3			2
18	6260 WILMINGTON TAP		138.00	138.00	1	1.00	9.00	1
19	6229 DUNLAP NORTH TAP		34.00	138.00	1	2.00		2
20	6140 INDIANA-PURDUE		34.00	138.00	1			2
21	6217 HILLCREST	KINNERK	69.00	138.00	1	3.92		1
22	6217 HILLCREST	KINNERK	69.00	138.00	2	0.03		1
23	6252 KENDALLVILLE	BIXLER	138.00	138.00	1	2.91		1
24	6254 ALLEN/LINCOLN	ALLEN/HILLCREST	138.00	138.00				
25	6271 INDALEX TAP/CR 4	EAST ELKHART	138.00	138.00	1	1.09		
26	6267 STUDEBAKER	WEST SIDE	138.00	138.00	1	2.57		1
27	6270 JONES CREEK	HOGAN	138.00	138.00		5.62		
28	6273 DAWKINS SWITCH	HERBERT MONROE (WVPA)	138.00	138.00	1	0.50		1
29								
30	LINES<132 KV	SYSTEM	69.00		Various	830.22	72.00	1
31								
32	STATE OF MICHIGAN							
33	6216 D.C. COOK	DUMONT	765.00	765.00	3	16.00		1
34	6120 COOK	PALISADES	345.00	345.00	3	41.78		2
35	6120 COOK	PALISADES	345.00	345.00	1	0.23		
36					TOTAL	3,923.33	127.09	248

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
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. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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.
6. 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.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	6120 COOK	PALISADES	345.00	345.00	1	0.21		
2	6143 D.C. COOK	OLIVE-PALISADES	345.00	345.00	3	5.00		2
3	6144 TWIN BRANCH	COOK-ROB PARK JCT	345.00	345.00	3			2
4	6151 COOK	OLIVE	345.00	345.00				
5	6152 COOK	ROBISON PARK	345.00	345.00				
6	6146 D.C. COOK	ROBISON PARK	345.00	345.00	3	37.00		2
7	6146 D.C. COOK	ROBISON PARK	345.00	345.00	3	0.09		
8	6214 COOK-ROB PARK	ARGENTA	345.00	345.00	3	28.78		2
9	6214 COOK-ROB PARK	ARGENTA	345.00	345.00	1	0.22		2
10	6221 D.C. COOK	OLIVE-PALISADES	345.00	345.00	3	5.00		2
11	6263 BARODA TAP		138.00	138.00				
12	0601 TWIN BRANCH	RIVERSIDE	138.00	138.00	3	33.00		2
13	0610 AUTO SPECIALTIES		138.00	138.00				
14	0621 TWIN BRANCH - R	HICKORY CREEK	138.00	138.00	3	5.00		2
15	0644 RIVERSIDE	HARTFORD	138.00	138.00	2	14.22		1
16	0644 RIVERSIDE	HARTFORD	138.00	138.00	3	2.11		
17	0649 COREY TAP		138.00	138.00	2	12.12		1
18	0649 COREY TAP		138.00	138.00	1	0.13		1
19	6108 RIVERSIDE	OLIVE-HICKORY CREEK	138.00	138.00	1	6.00		1
20	6124 BENTON HARBOR	RIVERSIDE-HARTFORD	138.00	138.00	3	1.00		2
21	6137 EDGEWATER TAP		138.00	138.00	1	0.76		1
22	6139 BENTON HARBOR	TWIN BRANCH-R SIDE	138.00	138.00	3	6.00		2
23	6149 HARTFORD	COREY	138.00	138.00	1	18.97		1
24	6149 HARTFORD	COREY	138.00	138.00			2.11	1
25	6149 HARTFORD	COREY	138.00	138.00	2	12.88		1
26	6149 HARTFORD	COREY	138.00	138.00			0.98	1
27	6149 HARTFORD	COREY	138.00	138.00	1	1.34		1
28	6149 HARTFORD	COREY	138.00	138.00	1	0.53		2
29	6218 MOTTVILLE TAP		138.00	138.00	1	1.00		1
30	6255 KENZIE CREEK	VALLEY	138.00	138.00	1	20.00		1
31	6257 KENZIE CREEK	T B/R'SIDE/HICK CR	138.00	138.00	3			
32	6261 FLATBUSH TAP		138.00	138.00		1.00		1
33	6262 WEST ST TAP		138.00	138.00		1.00		2
34	6700 GM HYDRAMATIC		138.00	138.00	3	2.00		2
35	6227 NICKERSON	TOWER #13A	138.00	138.00				
36					TOTAL	3,923.33	127.09	248

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Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
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. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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.
6. 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.

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
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	0643 OLIVE	HICKORY CREEK	138.00	138.00	3	22.80	2.00	1
2	6268 SAUK TRAIL		138.00	138.00	1	1.60		
3								
4	LESS THAN 132 KV LINES		69.00		Various	403.58	12.00	
5								
6	Line cost and expense are	not available by individual						
7	transmission line.	Total shown in column j-p						
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	3,923.33	127.09	248

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Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
4-954 KCM								2
4-954 KCM								3
4-954 KCM								4
4-954 KCM								5
4-954 KCM								6
4-1351 KCM								7
4-1351 KCM								8
								9
4-1351 KCM								10
1275 KCM								11
1275 KCM								12
2-954 KCM								13
1414 KCM								14
2-1351.5 KCM								15
2-2303 KCM								16
2303 KCM								17
2156 KCM								18
1414 KCM								19
1414 KCM								20
2-954 KCM								21
2-954 KCM								22
2-954 KCM								23
2-954 KCM								24
1414 KCM								25
1563 KCM								26
2-1024 KCM								27
2-1351.5 KCM								28
2-954 KCM								29
2-1351.5 KCM								30
1414 KCM								31
1414 KCM								32
2-954 KCM								33
2-954 KCM								34
2-954 KCM								35
	67,280,570	677,629,885	744,910,455	268,878	6,779,372		7,048,250	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

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9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2-954 KCM								1
								2
2-954 KCM								3
2-954 KCM								4
2-954 KCM								5
2-954 KCM								6
2303 KCM								7
2-954 KCM								8
								9
								10
1351.5 KCM								11
1351.5 KCM								12
1351.5 KCM								13
2-954 KCM								14
								15
397.5 KCM								16
397.5 KCM								17
397.5 KCM								18
1233.6 KCM								19
397.5 KCM								20
397.5 KCM								21
1233.6 KCM								22
397.5 KCM								23
397.5 KCM								24
336.4 KCM								25
636 KCM								26
336.4 KCM								27
397.5 KCM								28
447 KCM								29
397.5 KCM								30
477 KCM								31
397.5 KCM								32
397.5 KCM								33
397.5 KCM								34
397.5 KCM								35
	67,280,570	677,629,885	744,910,455	268,878	6,779,372		7,048,250	36

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
397.5 KCM								1
795 KCM								2
397.5 KCM								3
795 KCM								4
636 KCM								5
556.5 KCM								6
477 KCM								7
795 KCM								8
636 KCM								9
556.5 KCM								10
556.5 KCM								11
556.5 KCM								12
556.5 KCM								13
556.5 KCM								14
300 KCM CU								15
556.5 KCM								16
1033.5 KCM								17
397.5 KCM								18
447 KCM								19
556.5 KCM								20
556.5 KCM								21
556.5 KCM								22
556.5 KCM								23
556.5 KCM								24
556.5 KCM								25
556.5 KCM								26
397.5 KCM								27
556.5 KCM								28
397.5 KCM								29
556.5 KCM								30
556.5 KCM								31
556.5 KCM								32
477 KCM								33
556.5 KCM								34
556.5 KCM								35
	67,280,570	677,629,885	744,910,455	268,878	6,779,372		7,048,250	36

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TRANSMISSION LINE STATISTICS (Continued)

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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
556.5 KCM								1
3.5IN OD								2
556.5 KCM								3
397.5 KCM								4
397.5 KCM								5
2-556.5 KCM								6
2-556.5 KCM								7
636 KCM								8
636 KCM								9
336.4 KCM								10
636 KCM								11
1233.6 KCM								12
636 KCM								13
556.5 KCM								14
636 KCM								15
745 KCM								16
636 KCM								17
795 KCM								18
								19
556.5 KCM								20
795 KCM								21
795 KCM								22
1233.6 KCM								23
795 KCM								24
795 KCM								25
795 KCM								26
795 KCM								27
795 KCM								28
795 KCM								29
795 KCM								30
795 KCM								31
795 KCM								32
795 KCM AA								33
795 KCM								34
1033 KCM								35
	67,280,570	677,629,885	744,910,455	268,878	6,779,372		7,048,250	36

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TRANSMISSION LINE STATISTICS (Continued)

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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1033.5 KCM								1
556.5 KCM								2
795 KCM								3
795 KCM								4
795 KCM								5
795 KCM								6
795 KCM								7
1033.5 KCM								8
795 KCM								9
795 KCM								10
1033 KCM								11
1233.6 KCM								12
1033 KCM								13
1233.6 KCM								14
795 KCM								15
795 KCM								16
1033 KCM								17
2-954 KCM								18
795 KCM								19
1033 KCM								20
795 KCM								21
795 KCM								22
795 KCM								23
								24
								25
954 KCM								26
								27
4/0								28
								29
VARIOUS								30
								31
								32
4-954 KCM								33
2-954 KCM								34
2-954 KCM								35
	67,280,570	677,629,885	744,910,455	268,878	6,779,372		7,048,250	36

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TRANSMISSION LINE STATISTICS (Continued)

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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2-1158.4 KCM								1
2-954 KCM								2
2-954 KCM								3
								4
								5
2-954 KCM								6
954 KCM								7
2-954 KCM								8
2-954 KCM								9
2-954 KCM								10
								11
397.5 KCM								12
								13
397.5 KCM								14
397.5 KCM								15
397.5 KCM								16
477 KCM								17
477 KCM								18
636 KCM								19
795 KCM								20
556.5 KCM								21
795 KCM								22
795 KCM								23
795 KCM								24
795 KCM								25
1033.5 KCM								26
1033.5 KCM								27
1033.5 KCM								28
795 AA								29
1033 KCM								30
795 KCM								31
								32
								33
795 KCM								34
								35
	67,280,570	677,629,885	744,910,455	268,878	6,779,372		7,048,250	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
556.5 KCM								1
1033.5KCM								2
								3
VARIOUS								4
								5
	67,280,570	677,629,885	744,910,455	268,878	6,779,372		7,048,250	6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
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								29
								30
								31
								32
								33
								34
								35
	67,280,570	677,629,885	744,910,455	268,878	6,779,372		7,048,250	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	NO LINES ADDED						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
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37							
38							
39							
40							
41							
42							
43							
44	TOTAL						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINES ADDED DURING YEAR (Continued)

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.

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
									2
									3
									4
									5
									6
									7
									8
									9
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									42
									43
									44

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ADAMS (IM) - IN	T	138.00	13.00	
2	ADAMS (IM) - IN	T	138.00	69.00	34.00
3	ALBANY (IM) - IN	D	34.50	13.00	
4	ALBION - IN	T	69.00	12.00	
5	ALBION - IN	T	138.00	69.00	12.00
6	ALBION - IN	T	138.00		
7	ALBION - IN	T	69.00		
8	ALEXANDRIA - IN	D	34.50		
9	ALEXANDRIA - IN	D	34.50	4.00	
10	ALEXANDRIA - IN	D	34.50	13.00	
11	ALLEN (IM) - IN	T	345.00	137.50	13.80
12	ALMENA - MI	T	69.00	12.00	
13	ALMENA - MI	T	69.00	34.50	
14	AM GENERAL #1 - IN	D	34.50	4.00	
15	ANACONDA - IN	D	34.50	4.00	
16	ANCHOR HOCKING (IM) - IN	D	69.00	13.09	
17	ANCHOR HOCKING (IM) - IN	D	69.00	2.40	
18	ANTHONY - IN	T	34.50	12.00	
19	ANTHONY - IN	T	138.00	34.00	
20	ANTIVILLE - IN	D	69.00	12.00	
21	ARMSTRONG CORK - IN	D	69.00	4.00	
22	ARNOLD HOGAN - IN	T	138.00	13.09	
23	ARNOLD HOGAN - IN	T	34.50		
24	AUBURN - IN	T	138.00		
25	AUBURN - IN	T	138.00	70.50	36.20
26	BANGOR - MI	D	69.00	12.00	
27	BARLEY - IN	D	34.50	13.00	
28	BARODA - MI	D	138.00	13.09	
29	BEECH ROAD - IN	D	138.00	13.09	
30	BENTON HARBOR - MI	T	345.00	137.50	13.80
31	BENTON HARBOR - MI	T	345.00	137.50	13.14
32	BENTON HARBOR WATERWORKS - MI	D	34.50	13.00	
33	BERNE - IN	D	69.00	12.00	
34	BERNE - IN	D	69.00		
35	BERRIEN SP HYDR STAT - MI	T	34.50	13.00	
36	BERRIEN SP HYDR STAT - MI	T	34.50	12.00	
37	BETHEL - IN	D	34.50	13.00	
38	BIG RUN - IN	T	69.00	0.48	
39	BIXLER - IN	D	138.00	13.09	
40	BLAINE STREET - IN	D	34.50	13.00	

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Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SUBSTATIONS

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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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BLUFF POINT - IN	T	69.00	13.00	
2	BLUFF POINT - IN	T	69.00		
3	BOSMAN - IN	D	34.50	13.00	
4	BRIDGMAN - MI	D	69.00		
5	BRIDGMAN - MI	D	69.00	12.00	
6	BUCHANAN HYDRO STA - MI	T	69.00	12.00	
7	BUCHANAN HYDRO STA - MI	T	69.00	34.00	
8	BUCHANAN SOUTH - MI	D	69.00	12.00	
9	BUTLER (IM) - IN	D	69.00		
10	BUTLER (IM) - IN	D	69.00	13.00	
11	CALVERT - IN	D	138.00	13.09	
12	CAMERON - MI	D	69.00	34.00	
13	CAPITAL AVENUE - IN	T	138.00	13.09	
14	CARROLL - IN	D	34.50	13.00	
15	CHARLES - IN	D	34.50	13.00	
16	CHURUBUSCO - IN	D	34.50	13.00	
17	CHURUBUSCO - IN	D	34.50		
18	CLEVELAND - IN	D	138.00	13.09	
19	CLIPPER - IN	D	69.00	13.09	
20	COLBY - MI	T	138.00	13.09	
21	COLBY - MI	T	69.00	34.50	
22	COLBY - MI	T	138.00	69.00	34.50
23	COLBY - MI	T	34.50		
24	COLFAX - IN	D	34.50	12.00	
25	COLONY BAY - IN	D	69.00	13.00	
26	COLONY BAY - IN	D	69.00	12.00	
27	COLUMBIA(IM) - IN	T	138.00	69.00	34.00
28	CONANT - IN	D	34.50	12.00	
29	CONCORD - IN	T	138.00		
30	CONCORD - IN	T	138.00	13.09	
31	CONCORD - IN	T	138.00	13.09	
32	COUNTRYSIDE - IN	D	138.00	12.47	
33	COUNTY LINE (IM) - IN	D	138.00	13.09	
34	COUNTY ROAD 4 - IN	D	138.00	13.09	
35	COVERT - MI	D	69.00	13.00	
36	CROSS STREET - IN	D	138.00	13.09	
37	CRYSTAL - MI	D	138.00	13.09	
38	DALEVILLE - IN	D	138.00	13.09	
39	DARDEN ROAD - IN	D	138.00	13.09	
40	DC COOK 69/12 - MI	T	69.00	13.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	DC COOK 69/12 - MI	T	69.00		
2	DECATUR (FTW) - IN	T	69.00		
3	DECATUR (FTW) - IN	T	69.00	4.00	
4	DECATUR (FTW) - IN	T	69.00	13.00	
5	DEER CREEK - IN	T	34.50	13.09	
6	DEER CREEK - IN	T	138.00	13.09	
7	DEER CREEK - IN	T	138.00	69.00	34.00
8	DEER CREEK - IN	T	138.00		
9	DEER CREEK - IN	T	34.50		
10	DEER CREEK - IN	T	138.00	34.50	
11	DELAWARE (IM) - IN	T	138.00	34.00	
12	DELAWARE (IM) - IN	T	138.00		
13	DELAWARE (IM) - IN	T	34.50		
14	DERBY - MI	T	138.00	69.00	34.50
15	DESOTO - IN	T	345.00	138.00	34.50
16	DIEBOLD ROAD - IN	D	69.00	13.00	
17	DOOVILLE - IN	D	138.00	13.09	
18	DRAGOON - IN	T	138.00	69.00	34.00
19	DRAGOON - IN	T	34.50		
20	DREWRYS - IN	D	34.50	13.09	
21	DREWRYS - IN	D	34.50	12.00	
22	DUMONT - IN	T	765.00	345.00	34.50
23	DUMONT - IN	T	765.00	345.00	34.00
24	DUMONT - IN	T	765.00	345.00	17.00
25	DUMONT - IN	T	765.00		
26	DUNLAP - IN	T	138.00	69.00	34.00
27	DUNLAP - IN	T	138.00	13.09	
28	DUNLAP - IN	T	138.00	13.09	
29	EAST ELKHART - IN	T	345.00	137.50	13.80
30	EAST ELKHART - IN	T	138.00	69.00	34.00
31	EAST ELKHART - IN	T	34.50	7.20	
32	EAST SIDE (IM) - IN	D	138.00	13.09	
33	EAST WATERVLIET - MI	D	138.00	13.09	
34	EAU CLAIRE - MI	D	34.50	13.00	
35	EGE - IN	D	138.00	34.50	13.00
36	ELCONA - IN	D	138.00	13.09	
37	ELKHART HYDRO STAT - IN	T	34.50	13.00	
38	ELKHART HYDRO STAT - IN	T	34.50		
39	ELLISON ROAD - IN	T	138.00	13.09	
40	ELMRIDGE - IN	D	34.50	13.00	

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Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ELWOOD (IM) - IN	D	34.50	13.00	
2	ELWOOD (IM) - IN	D	34.50		
3	FAIRMOUNT - IN	D	34.50	7.20	
4	FARMLAND - IN	D	69.00	13.09	
5	FERGUSON - IN	D	69.00	13.00	
6	FISHER BODY - IN	D	138.00	13.80	
7	FLORENCE ROAD - MI	D	69.00	12.00	
8	FLORENCE ROAD - MI	D	69.00		
9	FULTON (IM) - IN	D	34.50	13.00	
10	GAS CITY - IN	D	34.50	13.00	
11	GAS CITY - IN	D	34.50		
12	GASTON - IN	D	138.00	13.09	
13	GATEWAY (IM) - IN	T	69.00		
14	GATEWAY (IM) - IN	T	69.00	34.00	
15	GERMAN - IN	D	138.00	13.09	
16	GLENBROOK - IN	D	34.50	13.00	
17	GRABILL - IN	D	138.00	13.09	
18	GRANGER - IN	D	138.00	12.47	
19	GRANGER - IN	D	138.00	13.09	
20	GRANT - IN	T	138.00	13.09	
21	GRANT - IN	T	138.00	34.50	
22	GRAVEL PIT - IN	D	34.50	12.00	
23	GREENLEAF - IN	D	34.50	13.09	
24	GREENTOWN - IN	T	765.00		
25	HACIENDA - IN	D	138.00	13.09	
26	HACIENDA - IN	D	138.00	13.09	
27	HADLEY - IN	D	69.00	13.00	
28	HAGAR - MI	D	69.00	12.00	
29	HAMILTON - IN	D	69.00	13.00	
30	HARLAN - IN	D	69.00	13.09	
31	HARLAN - IN	D	69.00	13.00	
32	HARPER - IN	D	138.00	13.09	
33	HARRISON STREET - IN	D	34.50	4.00	
34	HARTFORD - MI	T	138.00	69.00	34.00
35	HARTFORD - MI	T	69.00	12.00	
36	HARTFORD CITY - IN	T	69.00		
37	HARTFORD CITY - IN	T	69.00	13.00	
38	HARTFORD CITY - IN	T	69.00	34.00	
39	HARVEST PARK - IN	D	34.50	13.00	
40	HAYMOND - IN	D	34.50	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	HICKORY CREEK - MI	T	34.50	12.00	
2	HICKORY CREEK - MI	T	138.00	34.50	
3	HICKORY CREEK - MI	T	138.00	69.00	34.50
4	HILLCREST - IN	T	138.00	13.09	
5	HILLCREST - IN	T	138.00		
6	HUMMEL CREEK - IN	T	138.00	69.00	34.00
7	HUMMEL CREEK - IN	T	138.00	13.09	
8	ILLINOIS ROAD - IN	T	138.00	13.09	
9	ILLINOIS ROAD - IN	T	138.00	69.00	13.00
10	INDIAN LAKE - MI	D	34.50	13.00	
11	INDUSTRIAL PARK - IN	T	138.00		
12	INDUSTRIAL PARK - IN	T	138.00	69.00	34.00
13	INDUSTRIAL PARK - IN	T	138.00	13.09	
14	INDUSTRIAL PARK - IN	T	34.50	13.00	
15	IRELAND ROAD - IN	D	138.00	13.09	
16	IU PURDUE - IN	D	13.80	4.00	
17	JACKSON ROAD - IN	T	138.00	13.09	
18	JACKSON ROAD - IN	T	345.00	138.00	34.00
19	JACKSON ROAD - IN	T	138.00	34.00	
20	JAY (IM) - IN	T	138.00	69.00	34.00
21	JAY (IM) - IN	T	138.00	13.09	
22	JAY (IM) - IN	T	138.00		
23	JEFFERSON (IM) - IN	T	138.00		
24	JEFFERSON (IM) - IN	T	765.00		
25	JOBES - IN	D	34.50	4.00	
26	JONES CREEK - IN	D	138.00	12.47	
27	KANKAKEE - IN	T	138.00	13.09	
28	KENDALLVILLE - IN	T	69.00	13.00	
29	KENDALLVILLE - IN	T	69.00	12.00	
30	KENDALLVILLE - IN	T	138.00		
31	KENDALLVILLE - IN	T	138.00	69.00	13.00
32	KENZIE CREEK - MI	T	345.00	137.50	13.80
33	KINGSLAND - IN	D	69.00	13.00	
34	KLINE - IN	T	138.00	34.00	
35	KLINE - IN	T	34.50		
36	LAKE STREET - MI	T	69.00	34.00	
37	LAKE STREET - MI	T	69.00		
38	LAKESIDE (MBH) - MI	D	69.00	12.00	
39	LAKESIDE (MBH) - MI	D	69.00	13.09	
40	LANGLEY (IM) - MI	D	34.50	13.00	

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	LANTERN PARK - IN	D	138.00	13.09	
2	LAPAZ - IN	D	34.50	13.00	
3	LAPORTE JUNCTION - IN	T	138.00	69.00	34.00
4	LIGONIER - IN	D	138.00	13.09	
5	LINCOLN - IN	T	138.00	36.20	
6	LINCOLN - IN	T	138.00	70.50	36.20
7	LINCOLN - IN	T	138.00	13.09	
8	LINCOLN - IN	T	138.00		
9	LINWOOD (IM) - IN	D	138.00	13.09	
10	LOBDELL - IN	D	69.00	0.48	
11	LUSHER AVENUE - IN	D	34.50	12.00	
12	LYDICK - IN	D	34.50	13.09	
13	LYNN - IN	D	69.00	13.00	
14	MADISON (IM) - IN	T	138.00	35.00	
15	MADISON (IM) - IN	T	34.50	13.09	
16	MAGLEY - IN	T	69.00	13.00	
17	MAGLEY - IN	T	138.00	69.00	13.00
18	MAIN STREET - MI	T	138.00	34.00	
19	MAIN STREET - MI	T	34.50	4.00	
20	MAIN STREET - MI	T	138.00	13.09	
21	MARION ETHANOL - IN	D	34.50	4.00	
22	MARION PLANT - IN	D	34.50	4.00	
23	MARION PLANT - IN	D	34.50		
24	MARION PLANT - IN	D	34.50	13.00	
25	MAYFIELD - IN	D	138.00	13.09	
26	MCCLURE - IN	D	34.50	4.00	
27	MCGALLIARD ROAD - IN	D	34.50	13.00	
28	MCKINLEY - IN	T	138.00		
29	MCKINLEY - IN	T	69.00		
30	MCKINLEY - IN	T	138.00	34.00	
31	MCKINLEY - IN	T	138.00	13.09	
32	MCKINLEY - IN	T	138.00	70.50	36.20
33	MEADOW LAKE SW - IN	T	345.00		
34	MEADOWBROOK - IN	T	34.50		
35	MEADOWBROOK - IN	T	138.00	35.00	
36	MEDFORD - IN	T	138.00	69.00	34.00
37	MEDFORD - IN	T	34.50		
38	MIDDLEBURY - IN	D	34.50	0.48	
39	MIER - IN	D	138.00	13.09	
40	MILLER AVENUE - IN	D	34.50	4.00	

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MISSISSINEWA - IN	D	138.00	13.09	
2	MOCK AVENUE - IN	D	34.50	4.00	
3	MODOC - IN	T	138.00	69.00	13.00
4	MODOC - IN	T	69.00	13.00	
5	MONROE (IM) - IN	D	69.00	13.00	
6	MONTPELIER - IN	D	69.00	13.00	
7	MOORE PARK - MI	T	138.00	69.00	34.50
8	MOORE PARK - MI	T	69.00		
9	MOORE PARK - MI	T	138.00	13.09	
10	MOTTVILLE - MI	T	138.00	69.00	34.50
11	MOTTVILLE - MI	T	69.00	12.00	
12	MULLIN - IN	T	34.50		
13	MULLIN - IN	T	138.00	34.00	
14	MURCH - MI	D	69.00	12.00	
15	MURCH - MI	D	69.00		
16	MURRAY - IN	D	69.00	13.00	
17	NEW BUFFALO - MI	D	69.00	12.00	
18	NEW CARLISLE - IN	T	138.00	34.50	
19	NEW CARLISLE - IN	T	34.50	13.00	
20	NILES - MI	T	69.00	34.00	
21	NILES - MI	T	69.00		
22	NILES - MI	T	69.00	13.09	
23	NORTH KENDALLVILLE - IN	D	69.00	12.00	
24	NORTH PORTLAND - IN	D	69.00	13.00	
25	NORTHLAND - IN	D	138.00	13.09	
26	NORTHWEST ELKHART - IN	D	34.50	12.00	
27	NORTHWEST ELKHART - IN	D	34.50	13.00	
28	NORTHWEST ELKHART - IN	D	34.50		
29	OHIO OIL - IN	D	34.50	13.00	
30	OHIO OIL - IN	D	34.50	2.40	
31	OLIVE - IN	T	345.00	138.00	34.50
32	OLIVE - IN	T	138.00	13.09	
33	OLIVE - IN	T	138.00	69.00	34.00
34	ORONOKO - MI	D	34.50	12.00	
35	OSOLO - IN	T	138.00	69.00	34.00
36	OSOLO - IN	T	34.50		
37	OSOLO - IN	T	138.00	13.09	
38	OSSIAN - IN	D	69.00	13.00	
39	PARKWAY - IN	D	34.50	13.00	
40	PARNELL - IN	D	34.50	13.09	

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

SUBSTATIONS

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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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PARNELL - IN	D	34.50	13.00	
2	PEACOCK - IN	D	34.50	13.00	
3	PEARL STREET - MI	D	34.50	12.00	
4	PENDLETON - IN	T	138.00	35.00	
5	PENDLETON - IN	T	34.50		
6	PENNVILLE - IN	D	138.00	34.00	13.00
7	PHILIPS - IN	D	69.00	0.48	
8	PIGEON RIVER - MI	D	69.00	12.00	
9	PINE ROAD - IN	D	138.00	13.09	
10	PIPE CREEK - IN	D	138.00	12.00	
11	PLEASANT - IN	D	69.00		
12	PLEASANT - IN	D	69.00	13.00	
13	POKAGON(MBH) - MI	T	69.00		
14	POKAGON(MBH) - MI	T	138.00	69.00	13.00
15	POKAGON(MBH) - MI	T	69.00	13.00	
16	PORTLAND (IM) - IN	D	69.00	13.00	
17	PRICE - IN	D	69.00	13.09	
18	QUINN - IN	D	34.50	13.09	
19	RANDOLPH - IN	T	34.50	12.00	
20	RANDOLPH - IN	T	69.00		
21	RANDOLPH - IN	T	138.00	69.00	13.00
22	RANDOLPH - IN	T	138.00	13.09	
23	REED - IN	D	138.00	13.09	
24	RENNER STREET - IN	D	69.00	0.48	
25	RICKERMAN ROAD - MI	D	138.00	13.09	
26	RIVERSIDE (IM) - MI	T	138.00		
27	RIVERSIDE (IM) - MI	T	138.00	13.09	
28	RIVERSIDE (IM) - MI	T	138.00	69.00	34.00
29	ROBISON PARK - IN	T	138.00		
30	ROBISON PARK - IN	T	138.00	13.09	
31	ROBISON PARK - IN	T	138.00	13.09	
32	ROBISON PARK - IN	T	138.00	70.50	36.20
33	ROCKPORT - IN	T	34.50	13.00	
34	ROCKPORT - IN	T	138.00		
35	ROCKPORT - IN	T	765.00		
36	ROSE HILL - IN	D	138.00	13.00	
37	ROYERTON - IN	D	138.00	13.09	
38	SATURN - IN	T	138.00	13.09	
39	SAUK TRAIL - MI	D	138.00	13.09	
40	SCHOOLCRAFT - MI	D	69.00	13.00	

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SUBSTATIONS

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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).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	SCOTTDALE - MI	D	34.50	13.00	
2	SCOTTDALE - MI	D	34.50	13.09	
3	SELMA PARKER - IN	T	138.00	13.09	
4	SHARON ROAD - IN	D	34.50	13.00	
5	SILVER LAKE - IN	D	34.50	12.00	
6	SISTER LAKES - MI	D	34.50	12.00	
7	SODUS - MI	D	138.00	13.09	
8	SORENSON - IN	T	345.00	138.00	34.50
9	SORENSON - IN	T	138.00	13.09	
10	SORENSON - IN	T	345.00	138.00	34.00
11	SOUTH BEND - IN	T	138.00	34.00	
12	SOUTH BEND - IN	T	138.00	13.09	
13	SOUTH BEND - IN	T	138.00	69.00	34.00
14	SOUTH BEND - IN	T	138.00		
15	SOUTH BERNE - IN	D	69.00	12.00	
16	SOUTH DECATUR - IN	D	69.00	13.00	
17	SOUTH DECATUR - IN	D	69.00	13.09	
18	SOUTH ELWOOD - IN	T	138.00	13.09	
19	SOUTH ELWOOD - IN	T	138.00	34.00	
20	SOUTH SIDE (MARION) - IN	D	34.50	13.09	
21	SOUTH SIDE (SOUTH BEND) - IN	D	138.00	13.09	
22	SOUTH SUMMITVILLE - IN	T	34.50	13.09	
23	SOYA - IN	D	34.50	4.00	
24	SPRING STREET - IN	D	34.50	13.00	
25	SPRING STREET - IN	D	34.50	12.00	
26	SPRINGVILLE - IN	D	69.00	13.00	
27	SPY RUN 34 - IN	D	34.50	12.00	
28	SPY RUN SF6 - IN	T	138.00	34.00	
29	SPY RUN SF6 - IN	T	138.00	13.09	
30	ST MARYS COLLEGE - IN	D	34.50	4.33	
31	ST. JOE - IN	D	69.00	13.09	
32	STATE STREET - IN	D	138.00	13.09	
33	STEVENSVILLE - MI	D	69.00	13.09	
34	STEVENSVILLE - MI	D	69.00	13.00	
35	STONE LAKE - MI	D	69.00	12.00	
36	STONE LAKE - MI	D	69.00	13.00	
37	STUBEY ROAD - MI	D	69.00		
38	STUBEY ROAD - MI	D	69.00	12.00	
39	STUDEBAKER - IN	D	138.00	13.80	
40	STUDEBAKER - IN	D	138.00	13.09	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SULLIVAN (IM) - IN	T	138.00		
2	SULLIVAN (IM) - IN	T	765.00		
3	SUMMIT - IN	D	138.00	13.09	
4	SWANSON - IN	D	69.00	34.00	
5	SWANSON - IN	D	69.00		
6	THOMAS ROAD - IN	D	69.00	13.09	
7	THREE M - IN	D	69.00	4.00	
8	THREE OAKS - MI	D	69.00	12.00	
9	THREE RIVERS (FTW) - IN	D	34.50	13.00	
10	THREE RIVERS (FTW) - IN	D	34.50	14.40	
11	THREE RIVERS (MBH) - MI	D	69.00	12.00	
12	TILLMAN - IN	T	138.00	13.09	
13	TILLMAN - IN	T	138.00	36.20	
14	TILLOTSON - IN	D	34.50	13.00	
15	TORRINGTON - IN	D	34.50	4.00	
16	TRIER - IN	D	138.00	13.09	
17	TRI-LAKES - IN	D	69.00	13.00	
18	TWENTY FIRST STREET - IN	D	34.50	13.00	
19	TWENTY THIRD STREET (IM) - IN	T	34.50		
20	TWENTY THIRD STREET (IM) - IN	T	138.00	69.00	34.00
21	TWIN BRANCH 34KV - IN	T	34.50	13.00	
22	TWIN BRANCH 34KV - IN	T	34.50		
23	TWIN BRANCH 138KV - IN	T	345.00	138.00	34.50
24	TWIN BRANCH 138KV - IN	T	138.00	13.09	
25	TWIN BRANCH 138KV - IN	T	345.00	137.50	13.20
26	UNIVERSAL TOOL - IN	D	69.00	0.48	
27	UP RIVER DAM - IN	D	13.80	4.00	
28	UP RIVER DAM - IN	D	34.50	4.00	
29	UPLAND - IN	D	69.00	13.20	
30	UTICA (IM) - IN	D	34.50	13.09	
31	VALLEY - MI	T	138.00	69.00	34.00
32	VAN BUREN - IN	T	138.00	69.00	13.00
33	VICKSBURG - MI	D	69.00	12.00	
34	VICKSBURG - MI	D	69.00	13.09	
35	WABASH AVENUE - IN	D	69.00	13.09	
36	WALLEN - IN	T	138.00	69.00	34.00
37	WALLEN - IN	T	138.00	13.09	
38	WARREN - IN	D	69.00	12.00	
39	WATER POLLUTION - IN	D	34.50	4.00	
40	WAYNE TRACE - IN	D	138.00	13.09	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WAYNEDALE - IN	D	138.00	13.09	
2	WAYNEDALE - IN	D	138.00	12.47	
3	WEBSTER - IN	D	34.50	12.00	
4	WEBSTER - IN	D	34.50	14.00	
5	WEBSTER - IN	D	34.50	14.40	
6	WES-DEL - IN	D	138.00	13.09	
7	WEST END - IN	D	34.50	13.00	
8	WEST END - IN	D	34.50	4.00	
9	WEST SIDE - IN	T	138.00	13.09	
10	WEST SIDE - IN	T	34.50		
11	WEST SIDE - IN	T	138.00	69.00	34.00
12	WEST STREET - MI	D	138.00	13.09	
13	WHEELER STREET - MI	D	69.00	13.00	
14	WHITAKER - IN	D	34.50	12.00	
15	WHITLEY SW - IN	T	34.50		
16	WINCHESTER (IM) - IN	T	69.00		
17	WINCHESTER (IM) - IN	T	69.00	13.00	
18	WINCHESTER (IM) - IN	T	69.00	34.00	
19	WOLF LAKE - IN	D	69.00	13.00	
20	WOLVERINE - MI	D	69.00	13.00	2.40
21	WOODBURN - IN	D	69.00	13.00	
22	WOODS ROAD - IN	D	138.00	12.00	
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
13	1					1
115	1					2
9	1					3
8	1					4
90	1					5
			STATCAP	1	53	6
			STATCAP	1	14	7
			STATCAP	1	7	8
6	1					9
22	1					10
450	1					11
7	1					12
30	1					13
7	2					14
4	1					15
20	1					16
14	2					17
29	2					18
112	1					19
4	1					20
20	2					21
22	1					22
			STATCAP	2	29	23
			STATCAP	2	106	24
130	1					25
6	1					26
2	1					27
20	1					28
20	1					29
450	1					30
224		1				31
1	3					32
20	1					33
			STATCAP	1	16	34
5	1					35
5	1					36
11	1					37
3	1					38
20	1					39
29	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
6	1					1
			STATCAP	1	16	2
9	1					3
			STATCAP	1	14	4
19	2					5
8	1					6
20	1					7
22	1					8
			STATCAP	2	30	9
20	1					10
20	1					11
8	1					12
12	1					13
2	3					14
2	1					15
11	1					16
			STATCAP	1	5	17
20	1					18
6	1					19
8	1					20
20	1					21
75	1					22
			STATCAP	1	12	23
22	1					24
22	1					25
20	1					26
50	1					27
22	1					28
			STATCAP	1	53	29
22	1					30
22	1					31
20	1					32
20	1					33
20	1					34
9	1					35
20	1					36
22	1					37
20	1					38
42	2					39
7	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
			STATCAP	1		1
			STATCAP	1	13	2
5	1					3
20	1					4
4	1					5
20	1					6
90	1					7
			STATCAP	1	58	8
			STATCAP	2	30	9
75	1					10
125	2					11
			STATCAP	1	53	12
			STATCAP	1		13
75	1					14
675	1					15
20	1					16
12	1					17
84	1					18
			STATCAP	1	12	19
8	1					20
8	1					21
1000	2					22
500	1					23
1500	3					24
			REACTOR	2	200	25
130	1					26
20	1					27
20	1					28
450	1					29
84	1					30
1		1				31
37	2					32
20	1					33
4	1					34
8	1					35
22	1					36
8	1					37
			STATCAP	1	14	38
20	1					39
9	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
19	2					1
			STATCAP	1	5	2
11	1					3
20	1					4
20	1					5
100	2					6
20	1					7
			STATCAP	1	10	8
20	1					9
20	1					10
			STATCAP	1	10	11
20	1					12
			STATCAP	1	13	13
20	1					14
47	2					15
40	2					16
20	1					17
20	1					18
20	1					19
	1					20
30	1					21
5	1					22
20	1					23
			REACTOR	3	300	24
20	1					25
25	1					26
40	2					27
11	1					28
11	1					29
13	1					30
5	1					31
20	1					32
4	1					33
129	1					34
11	1					35
			STATCAP	1	16	36
20	1					37
20	1					38
20	1					39
24	2					40

SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
31	2					1
60	2					2
75	1					3
22	1					4
			STATCAP	1	53	5
75	1					6
20	1					7
20	1					8
84	1					9
2	1					10
			STATCAP	1	50	11
75	1					12
22	1					13
22	1					14
20	1					15
5	1					16
32	2					17
672	1					18
30	1					19
115	1					20
9	1					21
			STATCAP	1	58	22
			REACTOR	1	20	23
			REACTOR	10	850	24
9	1					25
20	1					26
22	1					27
8	1					28
11	1					29
			STATCAP	1	43	30
75	1					31
450	1					32
5	1					33
100	1					34
			STATCAP	1	14	35
40	1					36
			STATCAP	1	14	37
	1					38
9	1					39
17	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
20	1					1
5	1					2
84	1					3
29	2					4
75	1					5
200	1					6
20	1					7
			STATCAP	1	53	8
11	1					9
3	1					10
20	1					11
20	1					12
7	1					13
60	1					14
5	1					15
9	1					16
90	1					17
30	1					18
8	1					19
22	1					20
11	1					21
6	1					22
			STATCAP	1	9	23
22	1					24
20	1					25
8	1					26
29	2					27
			STATCAP	1	86	28
			STATCAP	1	22	29
112	1					30
40	2					31
130	1					32
			STATCAP	2		33
			STATCAP	2	29	34
100	1					35
75	1					36
			STATCAP	1	15	37
3	1					38
11	1					39
8	1					40

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
12	1					1
4	1					2
60	1					3
5	1					4
8	1					5
22	1					6
90	1					7
			STATCAP	1	16	8
20	1					9
54	1					10
3	1					11
			STATCAP	1	10	12
30	1					13
20	1					14
			STATCAP	1	13	15
5	1					16
31	2					17
30	1					18
8	1					19
45	1					20
			STATCAP	1	14	21
20	1					22
22	1					23
20	1					24
32	2					25
11	1					26
20	1					27
			STATCAP	1	14	28
6	1					29
6	6					30
675	1					31
9	1					32
27	1					33
8	1					34
75	1					35
			STATCAP	1	14	36
20	1					37
20	1					38
5	1					39
20	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
20	1					1
5	1					2
17	2					3
75	1					4
			STATCAP	2	26	5
8	1					6
3	1					7
20	1					8
20	1					9
20	1					10
			STATCAP	1	13	11
5	1					12
			STATCAP	1	14	13
115	1					14
5	1					15
17	2					16
20	1					17
9	1					18
4	1					19
			STATCAP	1	14	20
56	1					21
22	1					22
22	1					23
3		1				24
8	1					25
			STATCAP	1	53	26
20	1					27
134	2					28
			STATCAP	1	86	29
25	1					30
20	1					31
90	1					32
2	2					33
			REACTOR	2	40	34
			REACTOR	4	200	35
8	1					36
11	1					37
13	1					38
20	1					39
22	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
11	1					1
9	1					2
	1					3
2	3					4
20	1					5
15	2					6
11	1					7
675	1					8
9	1					9
675	1					10
150	2					11
20	1					12
130	1					13
			STATCAP	1	53	14
12	1					15
20	1					16
20	1					17
20	1					18
30	1					19
20	1					20
20	1					21
20	1					22
11	1					23
8	1					24
12	1					25
9	1					26
20	1					27
200	2					28
22	1					29
8	1					30
20	1					31
22	1					32
13	1					33
8	1					34
9	1					35
7	1					36
			STATCAP	1	14	37
11	1					38
36	2					39
20	1					40

SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
			REACTOR	1	20	1
			REACTOR	4	200	2
40	2					3
45	2					4
			STATCAP	1	14	5
20	1					6
13	1					7
6	1					8
10	2					9
22	2					10
22	1					11
	1					12
18	1					13
20	1					14
9	1					15
20	1					16
4	1					17
19	2					18
			STATCAP	2	29	19
213	2					20
3	1					21
			STATCAP	1	14	22
675	1					23
20	1					24
450	1					25
1	1					26
2	3					27
2	3					28
20	1					29
42	2					30
75	1					31
56	1					32
9	1					33
20	1					34
20	1					35
54	1					36
20	2					37
7	1					38
7	1					39
22	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
22	1					1
20	1					2
20	1					3
11	1					4
10	1					5
22	1					6
9	2					7
8	1					8
42	2					9
			STATCAP	1	12	10
84	1					11
20	1					12
8	1					13
20	1					14
			STATCAP	1	5	15
			STATCAP	2	22	16
26	2					17
17	1					18
8	1					19
5	1					20
11	1					21
10	1					22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Administrative and General Expenses - Operation	AEPSC	various	4,138,860
3	AEPSC Support Services	AEPSC	417	1,370,646
4	Assets and Other Debits - Utility Plant	SWEPCO	106,107,108	398,360
5	Central Machine Shop	APCO	various	2,719,069
6	Civil and Political Activities	AEPSC	426	685,345
7	Administrative and General Expenses - Maintenance	AEPSC	935	5,191,618
8	Coal Transloading	AEG	151	10,229,115
9	Construction Services	AEPSC	107,108,120	82,981,475
10	Customer Accounts Expense	AEPSC	901-905	8,564,186
11	Customer Service and Informational Expense	AEPSC	907,908,910	546,803
12	Distribution Expense - Operation	AEPSC	various	3,181,602
13	Distribution Expense - Operation	OPCO	various	289,593
14	Fleet and Vehicle Charges	APCO	various	702,865
15	Fuel and Storeroom Services	AEPSC	152,163	5,832,539
16	Hydraulic Power Generation - Maintenance	AEPSC	542-545	487,155
17	Hydraulic Power Generation - Operation	AEPSC	535,537-539	1,199,733
18	Materials and Supplies	AEP Texas	various	264,780
19	Materials and Supplies	APCO	various	859,959
20	**Non-power Goods or Services Provided for Affiliate**			
21	Assets and Other Debits - Deferred Debits	APCO	184	285,714
22	Assets and Other Debits - Utility Plant	AEP Texas	106-108	278,605
23	Assets and Other Debits - Utility Plant	IMTCO	107,108	7,114,038
24	Assets and Other Debits - Utility Plant	OPCO	106-108	444,802
25	Barging	AEG	417	15,308,033
26	Barging	APCO	417	37,184,803
27	Barging	KPCO	417	5,017,215
28	Building and Property Leases	AEPSC	454	991,553
29	Distribution Expenses - Maintenance	AEP Texas	592-595	411,491
30	Fleet and Vehicle Charges	AEPSC	various	403,307
31	Fleet and Vehicle Charges	APCO	various	657,650
32	Fuel Carbon Activation	AEG	154,502	6,649,342
33	Fuel Consumed Handling	AEG	152,501	5,576,237
34	Materials and Supplies	APCO	154	821,993
35	Materials and Supplies	IMTCO	154	4,461,868
36	Materials and Supplies	OPCO	154	3,028,065
37	Other Operating Revenues	APCO	456	341,096
38	Power Production - Steam Generation Operation	AEG	500,506	531,336
39	Rail Car Lease	SWEPCO	151	1,537,616
40	Services for Rockport	AEG	various	94,064,330
41	Sodium Bicarbonate Activation	AEG	154,502	7,277,939
42	Transmission Expenses - Maintenance	IMTCO	568-571,573	1,127,117
1	**Non-power Goods or Services Provided by Affiliated**			
2	Materials and Supplies	OPCO	various	2,145,851

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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.
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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 Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3	Nuclear Power Generation - Maintenance	AEPSC	528,530-532	1,913,483
4	Liabilities and Other Credits - Deferred Credits	SWEPCO	253	578,652
5	Nuclear Power Generation - Operation	AEPSC	517,520,523,524	903,597
6	Other Income and Deductions - Other Income	AGR	421	344,299
7	Other Income and Deductions - Other Income	APCO	417	6,190,025
8	Other Power Supply Expenses	AEPSC	555-557	6,033,330
9	Other Property and Investments	AEPSC	121,124	454,357
10	Rail Car Lease	PSO	186	250,752
11	Rail Car Lease	SWEPCO	186	897,719
12	Rail Car Maintenance	AEG	151	1,263,261
13	Research and Other Services	AEPSC	183,184,186,188	1,728,137
14	Steam Power Generation - Maintenance	AEPSC	510-514	1,734,451
15	Steam Power Generation - Operation	AEPSC	500,501,502,506	6,434,027
16	Transmission Expenses - Maintenance	AEPSC	various	659,105
17	Transmission Expenses - Operation	AEPSC	various	5,468,908
18	Audit Services	AEPSC	920,923	2,009,213
19	Corporate Accounting	AEPSC	920,923	4,086,504
20	**Non-power Goods or Services Provided for Affiliate**			
21	Transmission Expense - Operation	IMTCO	560,562,563,566	1,518,943
22	Use of Jointly Owned Facility	IMTCO	454	1,448,741
23	Barging	WPCO	417	5,017,214
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Corporate Communications	AEPSC	920,923	925,458
3	Corporate Planning & Budgeting	AEPSC	920,923	1,718,590
4	Corporate Safety & Health	AEPSC	920,923	665,853

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
5	Environmental Services	AEPSC	920,923	496,458
6	Human Resources	AEPSC	920,923	2,925,847
7	Information Technology	AEPSC	920,923	8,337,770
8	Legal GC/Administration	AEPSC	920,923	5,376,612
9	Real Estate & Workplace Services	AEPSC	920,923	3,171,184
10	Regulatory Services	AEPSC	920,923	1,762,206
11	Risk and Strategic Initiatives	AEPSC	920,923	1,100,796
12	Security & Aviation	AEPSC	920,923	764,584
13	Treasury & Investor Relations	AEPSC	920,923	1,138,789
14	Utility Operations	AEPSC	920,923	1,529,135
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Schedule Page: 429 Line No.: 2 Column: b

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.

Schedule Page: 429 Line No.: 2 Column: c

920,921,922,923,925,926,928,930,931

Schedule Page: 429 Line No.: 5 Column: c

107,108,163,500,506,512,513,524,530,531,543,544

Schedule Page: 429 Line No.: 12 Column: c

580,581,582,583,584,586,588,589

Schedule Page: 429 Line No.: 13 Column: c

580,583,584,586,587,588,589

Schedule Page: 429 Line No.: 14 Column: c

Costs related to AEP's fleet vehicles are allocated in the same manner as the labor of each department utilizing the vehicles. To the extent a department provides service to another affiliate company, an applicable share of their fleet costs are also assigned to that affiliate company.

Schedule Page: 429 Line No.: 18 Column: c

107,154,506,512,594

Schedule Page: 429 Line No.: 19 Column: c

107,108,154,512,513,530,531,543,544,570,588,592,935

Schedule Page: 429 Line No.: 30 Column: c

Costs related to AEP's fleet vehicles are allocated in the same manner as the labor of each department utilizing the vehicles. To the extent a department provides service to another affiliate company, an applicable share of their fleet costs are also assigned to that affiliate company.

Schedule Page: 429 Line No.: 31 Column: c

Costs related to AEP's fleet vehicles are allocated in the same manner as the labor of each department utilizing the vehicles. To the extent a department provides service to another affiliate company, an applicable share of their fleet costs are also assigned to that affiliate company.

Schedule Page: 429 Line No.: 40 Column: c

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.

Schedule Page: 429.1 Line No.: 2 Column: c

107,108,154,163,560,570,593,595,901,935

Schedule Page: 429.1 Line No.: 16 Column: c

568,569,570,571,572,573

Schedule Page: 429.1 Line No.: 17 Column: c

560,561,562,563,566,567