MICHIGAN PUBLIC SERVICE COMMISSION

ANNUAL REPORT OF ELECTRIC UTILITIES (MAJOR AND NON-MAJOR)

This form is authorized by 1919 PA 419, as amended, being MCL 460.55 et seq.; and 1969 PA 306, as amended, being MCL 24.201 et seq. Filing of this form is mandatory. Failure to complete and submit this form will place you violation of state law.

Report submitted for year ending:
December 31, 2018

Present name of respondent:
Indiana Michigan Power Company

Address of principal place of business:
1 Riverside Plaza, Columbus, OH 43215-2373

Utility representative to whom inquires regarding this report may be directed:

Name: Jerri-Lynn Ruggiero **Title:** Manager of Regulated Accounting

Address: 1 Riverside Plaza

City: Columbus **State:** Ohio **Zip:** 43215

Telephone, Including Area Code: (614) 716-2674

If the utility name has been changed during the past year:

Prior Name:

Date of Change:

Two copies of the published annual report to stockholders:

[ ] **were forwarded to the Commission**
[x] **will be forwarded to the Commission**

on or about April 30, 2019

Annual reports to stockholders:

[x] **are published**
[ ] **are not published**

FOR ASSISTANCE IN COMPLETION OF THIS FORM:

Contact the Michigan Public Service Commission (Heather Cantin) at (517) 284-8266 or cantinh@michigan.gov OR forward correspondence to:

Michigan Public Service Commission
Financial Analysis & Audit Division (Heather Cantin)
7109 W Saginaw Hwy
PO Box 30221
Lansing, MI 48909

MPSC FORM P-521

ANNUAL REPORT OF ELECTRIC UTILITIES, LICENSEES AND OTHERS (Major and Nonmajor)

IDENTIFICATION		
01 Exact Legal Name of Respondent Indiana Michigan Power Company	02 Year of Report December 31, 2018	
03 Previous Name and Date of Change (if name changed during year)		
04 Address of Principal Business Office at End of Year (Street, City, State, Zip) 1 Riverside Plaza, Columbus, OH 43215-2373		
05 Name of Contact Person Jerri-Lynn Ruggiero	06 Title of Contact Person Manager of Regulated Accounting	
07 Address of Contact Person (Street, City, State, Zip 1 Riverside Plaza, Columbus, OH 43215-2373		
08 Telephone of Contact Person, Including Area Code: (614) 716-2674	09 This Report is (1) [x] An Original (2) [ ] A Resubmission	10 Date of Report (Mo, Da, Yr)

ATTESTATION		
The undersigned officer certifies that he/she has examined the accompanying report; that to the best of his/her knowledge, information, and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the above named respondent in respect to each and every matter set forth therein during the period from and including January 1 and including December 31 of the year of the report.		
01 Name Jeffrey W. Hoersdig	03 Signature Jeffrey W Hoersdig	04 Date Signed (Mo, Da, Yr) April 24, 2019
02 Title Assistant Controller		

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Compar	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2018

LIST OF SCHEDULES (Electric Utility)

1. Enter in column (c) the terms "none", "not applicable", or "NA", as

2. The "M" prefix below denotes those pages where

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Compa	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2018

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)		Reference Page No. (b)	Remarks (c)
BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits) (Continued)			
Other Paid-In Capital		253	FERC Form 1
Discount on Capital Stock		254	NA
Capital Stock Expense		254	NA
Securities Issued and Redeemed During the Year	M	255	
Long-Term Debt		256-257	FERC Form 1
Payable to Associated Companies	M	260B	
Reconciliation of Reported Net Income with Taxable Income for Federal Income Tax	M	261A-B	
Calculation of Federal Income Tax			
Taxes Accrued, Prepaid and Charged During Year		262-263	FERC Form 1
Distribution of Taxes Charged			
Accumulated Deferred Investment Tax Credits		266-267	FERC Form 1
Miscellaneous Current and Accrued Liabilities	M	268	
Other Deferred Credits		269	FERC Form 1
Deferred Gains From Disposition of Plant	M	270	NA
Accumulated Deferred Income Taxes - Accelerated Amortization Property		272-273	FERC Form 1
Accumulated Deferred Income Taxes - Other Property		274-275	FERC Form 1
Accumulated Deferred Income Taxes - Other		276A-B	FERC Form 1
Other Regulatory Liabilities		278	FERC Form 1
Gain or Loss on Disposition of Property	M	280	
Income From Utility Plant Leased	M	281	NA
Particulars Concerning Certain Other Income Accounts	M	282	
INCOME ACCOUNT SUPPORTING SCHEDULES			
Electric Operating Revenues	M	300-301	
Customer Choice Electric Operating Revenues	M	302-303	NA
Sales of Electricity by Rate Schedules	M	304	
Customer Choice Sales of Electricity by Rate Schedules	M	305	NA
Sales for Resale		310-311	FERC Form 1
Electric Operation and Maintenance Expenses		320-323	
Number of Electric Department Employees		323	
Purchased Power		326-327	FERC Form 1
Transmission of Electricity for Others		328-330	FERC Form 1
Miscellaneous Revenue	M	331	
Transmission of Electricity by Others		332	FERC Form 1
Lease Rentals Charged	M	333	
Miscellaneous General Expenses - Electric		335	FERC Form 1
Depreciation and Amortization of Electric Plant		336	FERC Form 1
Depreciation and Amortization of Electric Plant		337	FERC Form 1
Particulars Concerning Certain Income Deduction and Interest Charges Accounts	M	340	
Expenditures For Certain Civic, Political and Related Activities	M	341	
Extraordinary Items	M	342	NA
COMMON SECTION			
Regulatory Commission Expenses		350-351	FERC Form 1
Research, Development and Demonstration Activities		352-353	FERC Form 1
Distribution of Salaries and Wages		354-355	FERC Form 1
Common Utility Plant and Expenses		356	NA
Charges for Outside Professional and Consultative Services	M	357	
ELECTRIC PLANT STATISTICAL DATA			
Monthly Transmission System Peak Load		400	NA
Electric Energy Account		401a	FERC Form 1
Monthly Peaks and Output		401b	FERC Form 1
Steam-Electric Generating Plant Statistics (Large Plants)		402-403	FERC Form 1
Hydroelectric Generating Plant Statistics (Large Plants)		406-407	NA
Pumped Storage Generating Plant Statistics (Large Plants)		408-409	NA
Generating Plant Statistics (Small Plants)		410-411	FERC Form 1
Changes Made or Scheduled to be Made in Generating Plants	M	412	
Steam-Electric Generating Plant Statistics (Large Plants)	M	413A/B	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Compar	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2018

LIST OF SCHEDULES (Electric Utility) (Continued)

As noted in column C, certain pages filed by Indiana Michigan Power Company are copies of the FERC Form 1. In such instances, the requirements of the FERC Form 1 meet or exceed those of the MPSC Form P-521.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2018

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 accounts 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 the fact and give the type of organization and date organized.

Indiana - February 21, 1925

3. If at any time during the year the property of respondent was held by 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 which possession by receivership or trustee ceased.

None

4. State the classes of utility or 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 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 2018/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Price River Coal Company, Inc.	Coal Company - Inactive	100	
2	Blackhawk Coal Company, Inc.	Coal Company - Inactive	100	
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Com	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2018

CONTROL OVER RESPONDENT & OTHER ASSOCIATED COMPANIES

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

2. List any entities which respondent did not control either directly or indirectly and which did not control respondent, but which were associated companies at any time during the year.

American Electric Power Company, Inc. - Ownership of 100% of the respondent's common stock

The following list of subsidiaries was extracted from Exhibit 21 of the company's Form 10-K as filed with the SEC.

Subsidiaries of American Electric Power Company, Inc., As of December 31, 2018

Each company shown indented is owned by the company immediately above it. Subsidiaries not indented are directly owned by the American Electric Power Company, Inc.

American Electric Power Service Corporation
AEP Energy Supply LLC
    AEP Generation Resources Inc.
AEP Generating Company
AEP Transmission Holding Company, LLC
    AEP Transmission Company, LLC
AEP Texas Inc.
    AEP Texas Central Transition Funding II LLC
    AEP Texas Central Transition Funding III LLC
    AEP Texas North Generation Company LLC
Appalachian Power Company
    Appalachian Consumer Rate Relief Funding LLC
Indiana Michigan Power Company
Kentucky Power Company
Kingsport Power Company
Ohio Power Company
    Ohio Phase-In-Recovery Funding LLC
Ohio Valley Electric Corporation
    Indiana-Kentucky Electric Corporation
Public Service Company of Oklahoma
Southwestern Electric Power Company
Wheeling Power Company

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

OFFICERS AND EMPLOYEES

1. Report below the name, title, and salary for the five executive officers.
2. Report in column (b) salaries and wages accrued during the year including deferred compensation.
3. In column (c) report any other compensation provided, such as bonuses, car allowance, stock options and rights, savings contribution, etc., and explain in a footnote what the amounts represent. Provide type code for other compensation in column (d).
4. If a change was made during the year in the incumbent of any position, show the name and total remuneration of the previous incumbent and the date the change in incumbency occurred.
5. Upon request, the Company will provide the Commission with supplemental information on officers and other employees and salaries.

Line	Name and Title (a)	Base Wages (b)	Other Compensation (c)	Type of Other Compensation (d)	Total Compensation (e)
1	Nicholas K. Akins	1,415,423	2,900,000	A	12,202,028
	Chairman of the Board and		89,766	B	
	Chief Executive Officer		7,564,313	C	
			232,526	D	
2	Brian X. Tierney	771,958	890,000	A	3,667,290
	Executive Vice President and		59,547	B	
	Chief Financial Officer		1,945,785	C	
			0	D	
3	David M. Feinberg	650,492	655,000	A	2,741,404
	Executive Vice President,		35,927	B	
	General Counsel and Secretary		1,362,082	C	
			37,903	D	
4	Lisa M. Barton	571,189	575,000	A	2,409,768
	Executive Vice President -		41,592	B	
	Transmission		1,167,470	C	
			54,517	D	
5	Lana L. Hillebrand	597,289	600,000	A	2,275,399
	Executive Vice President -		43,619	B	
	Chief Administrative Officer		972,924	C	
			61,567	D	
	Footnote Data				
1					
2					
3					
4					
5					

Compensation Type Codes:
A=Executive Incentive Compensation
B=Incentive Plan (Matching Employer Contribution)
C=Stock Plans
D=Other Reimbursements

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

DIRECTORS

1. Report below any 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.

Name and Title of Director (a)	Principal Business Address (b)	# of Directors Meetings During Yr (c)	Fees During Yr (d)
Nicholas K. Akins - Chief Executive Officer*** Chairman of the Board**	Columbus, Ohio	N/A	0
Mark C. McCullough - Vice President***	Columbus, Ohio	N/A	0
Marc E. Lewis - Vice President External and Regulatory Affairs	Fort Wayne, Indiana	N/A	0
Robert P. Powers***	Columbus, Ohio	N/A	0
Brian X. Tierney - Vice President*** Chief Financial Officer	Columbus, Ohio	N/A	0
Lisa M. Barton - Vice President***	Columbus, Ohio	N/A	0
Thomas A. Kratt - Vice President Distribution Region Operations	Fort Wayne, Indiana	N/A	0
Carla E. Simpson	Fort Wayne, Indiana	N/A	0
David A. Lucas - Vice President Finance	Fort Wayne, Indiana	N/A	0
Toby L. Thomas - President Chief Operating Officer	Fort Wayne, Indiana	N/A	0
Nicholas M. Elkins	Fort Wayne, Indiana	N/A	0

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

SECURITY HOLDERS AND VOTING POWERS

1. (A) Give the names and addresses of the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compilation of list of stockholders of the respondent, prior to the end of the year, had the highest voting powers in the respondent, and state the number of votes which each would have had the right to cast on that date if a meeting were then in order. If any such holder held in trust, give a footnote the known particulars of the trust (whether voting trust, etc.), duration of trust, and principal holders of beneficiary interests in the trust. If the stock book was not closed or a list of stockholders was not compiled within one year prior to the end of the year, or if since the previous compilation of a list of stockholders, some other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the titles of officers and directors included in such list of 10 security holders.

1. (B) Give also the name and indicate the voting powers resulting from ownership of securities of the respondent of each officer and director not included in the list of 10 largest security holders.
2. If any security other than stock carries voting rights, explain in a supplemental statement the circumstances whereby such security became vested with voting rights and give other important particulars (details) concerning the voting rights of such security. State whether voting rights are actual or contingent; if contingent, describe the contingency.
3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in the determination of corporate action by any method, explain briefly in a footnote.
4. Furnish particulars (details) concerning any options, warrants, or rights outstanding at the end of the year for others to purchase securities of the respondent or any securities or other assets owned by the respondent, including prices, expiration dates, and other material information relating to exercise of the options, warrants, or rights. Specify the amount of such securities or assets so entitled to be purchased by any officer, director, associated company, or any of the ten largest security holders. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the general public where the options, warrants, or rights were issued on a prorata basis.

1. Give date of the latest closing of the stock book prior to end of year, and state the purpose of such closing:

Stock books do not close

2. State the total number of votes cast at the latest general proxy meeting prior to the end of year for election of directors of the respondent and number of such notes cast by proxy:

Total: 1,400,000

By Proxy: 1,400,000

3. Give the date and place of such meeting:

April 25, 2017 in Charleston, West Virginia

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

SECURITY HOLDERS AND VOTING POWERS (Continued)

Line	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES Number of votes as of (date): Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
4	TOTAL votes all voting securities	1,400,000	1,400,000		
5	TOTAL number of security holders	1	1		
6	TOTAL votes of security holders listed below				
7	American Electric Power Company, Inc.	1,400,000	1,400,000		
8	1 Riverside Plaza				
9	Columbus, Ohio 43215				
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RESPONSE/NOTES TO INSTRUCTION

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
Effective January 19, 2018	Township of LaGrange, Cass County, Michigan	Ten (10) Year Franchise Renewal expiring on January 18, 2028	None
Renewed on August 20, 2018	Township of Baroda, Berrien County, Michigan	Thirty (30) year franchise renewal expiring on August 19, 2048	None
Renewed on August 14, 2018	Township of Mason, Cass County, Michigan	Thirty (30) year franchise renewal expiring on August 13, 2048	None
Renewed on August 27, 2018	City of Hartford, Van Buren County, Michigan	Thirty (30) year franchise renewal expiring on August 26, 2048	None
Renewed on September 17, 2018	City of Bridgman, Berrien County, Michigan	Thirty (30) year franchise renewal expiring on September 16, 2048	None
Renewed on September 18, 2018	Village of Grand Beach, Berrien County, Michigan	Thirty (30) year franchise renewal expiring on September 17, 2048	None
Renewed on September 4, 2018	Township of St. Joseph, Berrien County, Michigan	Thirty (30) year franchise renewal expiring on September 3, 2048	None
Renewed on August 14, 2018	Township of Pine Grove, Van Buren County, Michigan	Thirty (30) year franchise renewal expiring on August 13, 2048	None
Renewed on October 8, 2018	Township of Paw Paw, Van Buren County, Michigan	Thirty (30) year franchise renewal expiring on October 7, 2048	None

2. None

3. The letter with the final journal entries to clear Account 102 for the acquisition by Indiana & Michigan Power Company of the Losantville 345 kV switching station facilities and associated equipment from Headwaters Wind Farm LLC was submitted to the FERC on August 14, 2018. The Commission authorized the transaction in Docket No. EC17-69-000.

4. None

5. None

6. $200,000,000 Local Bank Facility (Indiana Commission Authority, Cause No. 44904)

   $350,000,000 Senior Unsecured Notes (Indiana Commission Authority, Cause No. 44904)

   $55,500,000 Nuclear Fuel Capital Lease (Indiana Commission Authority, Cause No. 44827)

   $475,000,000 Senior Unsecured Notes (Indiana Commission Authority, Cause No. 45057)

7. None

8. Cook Nuclear Plant Maintenance employees represented by IBEW #1392 were provided with a 2.5% general wage increase effective April 1, 2018

   Cook Nuclear Plant Stores employees represented by IBEW #1392 were provided with a 2.5% general wage increase effective April 1, 2018

   Cook Nuclear Plant RPEC employees represented by IBEW #1392 were provided with a 2.5% general wage increase effective April 1, 2018

   Michiana Region employees represented by IBEW #1392 were provided with a 2.5% general wage increase effective April 1, 2018

   Fort Wayne District employees represented by IBEW #1392 were provided with a 2.5% general wage increase effective April 1, 2018

   Muncie District employees represented by IBEW #1392 were provided with a 2.5% general wage increase effective April 1, 2018

   TFS T-Line employees represented by IBEW #1392 were provided with a 2.5% general wage increase effective April 1, 2018

   Southern Maintenance Group employees represented by IBEW #1392 were provided with a 2.5% general wage increase effective April 1, 2018

   Three Rivers Area employees represented by IBEW #876 were provided with a 2.5% general wage increase effective April 1, 2018

   Cook Plant Planners employees represented by IBEW 1392 - Impasse declared - No general increase.

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

10. None

11. (Reserved)

12. Not Used

13. Thomas Presthus elected as Vice President effective 1/1/2018
Mark A. Pyle resigned as Vice President - Tax effective 1/28/2018
Paul Chodak III elected as Vice President effective 4/26/2018
Marguerite C. Mills resigned as Vice President effective 8/11/2018
Mark J. Leskowitz elected as Vice President effective 8/12/2018
Daniel J. Rogier elected as Vice President effective 12/12/2018
Lonni L. Dieck resigned as Vice President and Treasurer effective 12/31/2018

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 2018/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	9,079,286,844	8,332,896,583
3	Construction Work in Progress (107)	200-201	465,252,782	460,208,619
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		9,544,539,626	8,793,105,202
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	3,068,176,859	2,948,719,776
6	Net Utility Plant (Enter Total of line 4 less 5)		6,476,362,767	5,844,385,426
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	32,268,259	37,447,359
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		1,602,198	1,347,289
10	Spent Nuclear Fuel (120.4)		518,765,415	695,441,601
11	Nuclear Fuel Under Capital Leases (120.6)		122,281,366	180,028,830
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	518,996,189	695,661,521
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		155,921,049	218,603,558
14	Net Utility Plant (Enter Total of lines 6 and 13)		6,632,283,816	6,062,988,984
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		25,913,836	28,139,049
19	(Less) Accum. Prov. for Depr. and Amort. (122)		11,826,528	12,180,000
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	19,317,612	19,061,859
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	25,667,168	27,124,423
24	Other Investments (124)		13,118,001	13,524,077
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		2,474,916,786	2,527,614,722
29	Special Funds (Non Major Only) (129)		67,030,229	71,055,571
30	Long-Term Portion of Derivative Assets (175)		576,115	720,561
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		2,614,713,219	2,675,060,262
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		2,363,490	1,326,155
36	Special Deposits (132-134)		16,141,429	11,624,090
37	Working Fund (135)		0	3,800
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		74,846,958	56,348,872
41	Other Accounts Receivable (143)		1,401,560	1,947,471
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		96,625	206,193
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		71,894,160	47,313,331
45	Fuel Stock (151)	227	36,307,472	30,732,935
46	Fuel Stock Expenses Undistributed (152)	227	981,098	621,540
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	163,849,568	156,944,999
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	2,044,990	2,112,441
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	27,088,587	28,650,949

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		25,667,168	27,124,423
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)		7,619,054	8,241,341
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		110,664	171,856
60	Rents Receivable (172)		88,144	87,047
61	Accrued Utility Revenues (173)		3,566,004	7,288,586
62	Miscellaneous Current and Accrued Assets (174)		31,087,103	16,882,969
63	Derivative Instrument Assets (175)		9,188,606	8,289,835
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		576,115	720,561
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)		422,238,979	350,537,040
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		20,189,248	12,912,315
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	547,960,064	604,411,370
73	Prelim. Survey and Investigation Charges (Electric) (183)		13,743,555	19,607,892
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)		7	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	52,053,453	49,654,743
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)		17,921,845	8,418,221
82	Accumulated Deferred Income Taxes (190)	234	771,937,131	1,096,784,602
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,423,805,303	1,791,789,143
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		11,093,041,317	10,880,375,429

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 2018/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	1,335,161,921	1,198,555,445
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-6,033,663	-6,289,416
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)	-13,760,206	-12,123,365
16	Total Proprietary Capital (lines 2 through 15)		2,352,848,357	2,217,622,969
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	2,928,439,660	2,574,997,049
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		8,698,985	5,626,318
24	Total Long-Term Debt (lines 18 through 23)		2,919,740,675	2,569,370,731
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		91,822,883	120,623,624
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		127,795	47,070
29	Accumulated Provision for Pensions and Benefits (228.3)		8,496,134	13,890,872
30	Accumulated Miscellaneous Operating Provisions (228.4)		681,435	952,363
31	Accumulated Provision for Rate Refunds (229)		18,630,953	8,298,302
32	Long-Term Portion of Derivative Instrument Liabilities		132,432	120,346
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		1,681,320,134	1,321,774,265
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,801,211,766	1,465,706,842
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		174,666,670	154,463,275
39	Notes Payable to Associated Companies (233)		1,063,378	211,574,416
40	Accounts Payable to Associated Companies (234)		70,184,459	98,281,769
41	Customer Deposits (235)		37,972,608	37,670,440
42	Taxes Accrued (236)	262-263	66,634,648	21,741,646
43	Interest Accrued (237)		38,362,308	38,833,706
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)		6,843,409	6,128,996
48	Miscellaneous Current and Accrued Liabilities (242)		95,580,780	97,907,431
49	Obligations Under Capital Leases-Current (243)		69,121,653	99,312,463
50	Derivative Instrument Liabilities (244)		407,099	3,602,082
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		132,432	120,346
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)		560,704,580	769,395,878
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	29,388,700	34,075,627
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	31,686,720	34,850,849
60	Other Regulatory Liabilities (254)	278	1,675,502,543	1,738,909,747
61	Unamortized Gain on Reaquired Debt (257)		8,131	9,843
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	17,764,010	17,658,664
63	Accum. Deferred Income Taxes-Other Property (282)		975,787,582	886,503,347
64	Accum. Deferred Income Taxes-Other (283)		728,398,253	1,146,270,932
65	Total Deferred Credits (lines 56 through 64)		3,458,535,939	3,858,279,009
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		11,093,041,317	10,880,375,429

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 2018/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	2,284,142,642	2,051,641,009		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,251,034,361	1,184,121,791		
5	Maintenance Expenses (402)	320-323	238,087,514	208,395,755		
6	Depreciation Expense (403)	336-337	256,272,563	179,225,778		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	2,017,956	1,723,493		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	34,770,845	29,698,986		
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)		29,418	295,199		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	95,184,341	88,676,779		
15	Income Taxes - Federal (409.1)	262-263	65,620,925	-107,960,156		
16	- Other (409.1)	262-263	15,997,681	-8,681,078		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	2,453,657,434	616,889,770		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	2,498,631,479	419,971,665		
19	Investment Tax Credit Adj. - Net (411.4)	266	-4,686,927	-4,705,788		
20	(Less) Gains from Disp. of Utility Plant (411.6)		938,029	285,054		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		41,311	406		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		7,302,976	8,248,773		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,915,678,268	1,775,672,177		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		368,464,374	275,968,832		

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 2018/Q4

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
2,284,142,642	2,051,641,009					2
						3
1,251,034,361	1,184,121,791					4
238,087,514	208,395,755					5
256,272,563	179,225,778					6
2,017,956	1,723,493					7
34,770,845	29,698,986					8
						9
						10
						11
29,418	295,199					12
						13
95,184,341	88,676,779					14
65,620,925	-107,960,156					15
15,997,681	-8,681,078					16
2,453,657,434	616,889,770					17
2,498,631,479	419,971,665					18
-4,686,927	-4,705,788					19
938,029	285,054					20
						21
41,311	406					22
						23
7,302,976	8,248,773					24
1,915,678,268	1,775,672,177					25
368,464,374	275,968,832					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 2018/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)		368,464,374	275,968,832		
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)		72,961,712	73,524,249		
34	(Less) Expenses of Nonutility Operations (417.1)		67,108,950	67,655,029		
35	Nonoperating Rental Income (418)		287,665	50,471		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	255,753	384,898		
37	Interest and Dividend Income (419)		3,128,895	1,655,200		
38	Allowance for Other Funds Used During Construction (419.1)		11,901,253	11,055,694		
39	Miscellaneous Nonoperating Income (421)		4,106,565	13,050,812		
40	Gain on Disposition of Property (421.1)		941,869			
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		26,474,762	32,066,295		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		76,361	146,558		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		1,934,692	548,496		
46	Life Insurance (426.2)					
47	Penalties (426.3)		81,396	-4,677		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,331,894	1,009,052		
49	Other Deductions (426.5)		10,164,892	3,027,326		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		13,589,235	4,726,755		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	3,770,381	3,493,553		
53	Income Taxes-Federal (409.2)	262-263	-4,798,821	1,446,300		
54	Income Taxes-Other (409.2)	262-263	-207,396	488,790		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	12,697,026	20,093,163		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	10,628,489	15,987,137		
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)		832,701	9,534,669		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		12,052,826	17,804,871		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		115,645,151	100,206,743		
63	Amort. of Debt Disc. and Expense (428)		2,440,850	2,129,649		
64	Amortization of Loss on Reaquired Debt (428.1)		1,368,597	1,252,844		
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)		1,921,471	2,624,419		
68	Other Interest Expense (431)		5,223,367	7,524,454		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		7,382,181	6,705,457		
70	Net Interest Charges (Total of lines 62 thru 69)		119,215,543	107,030,940		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		261,301,657	186,742,763		
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)		261,301,657	186,742,763		

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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 of Report December 31, 2018

RECONCILIATION OF DEFERRED INCOME TAX EXPENSE

1. Report on this page the charges to accounts 410, 411 and 420 reported in the contra accounts 190, 281, 282, 283 and 284.
2. The charges to the subaccounts of 410 and 411 found on pages 114-117 should agree with the subaccount totals reported on these pages.

In the event the deferred income tax expenses reported on pages 114-117 do not directly reconcile with the amounts found on these pages, then provide the additional information requested in instruction #3, on a separate page.

Line No.		Electric Utility	Gas Utility
1	Debits to Account 410 from:		
2	Account 190	578,288,766	
3	Account 281	12,516,230	
4	Account 282	1,504,670,071	
5	Account 283	353,520,070	
6	Account 284		
7	Reconciling Adjustments	4,662,297	
8	TOTAL Account 410.1 (on pages 114-115 line 17)	**2,453,657,434**	**0**
9	TOTAL Account 410.2 (on page 117 line 55)		
10	Credits to Account 411 from:		
11	Account 190	267,813,216	
12	Account 281	12,490,883	
13	Account 282	1,470,416,556	
14	Account 283	737,273,706	
15	Account 284		
16	Reconciling Adjustments	10,637,118	
17	TOTAL Account 411.1 (on page 114-115 line 18)	**2,498,631,479**	**0**
18	TOTAL Account 411.2 (on page 117 line 56)		
19	Net ITC Adjustment:		
20	ITC Utilized for the Year DR		
21	ITC Amortized for the Year CR	(4,686,927)	
22	ITC Adjustments:		
23	Adjust last year's estimate to actual per filed return		
24	Other (specify)		
25	Net Reconciling Adjustments Account 411.4*	**(4,686,927)**	**0**
26	Net Reconciling Adjustments Account 411.5**		
27	Net Reconciling Adjustments Account 420***		

* on pages 114-15 line 19 ** on page 117 line 57 *** on page 117 line 58

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2018

RECONCILIATION OF DEFERRED INCOME TAX EXPENSE

3. (a) Provide a detailed reconciliation of the applicable deferred income tax expense subaccount(s) reported on pages 114-117 with the amount reported on these pages. (b) Identify all contra accounts (other than accounts 190 and 281-284).

(c) Identify the company's regulatory authority to utilize contra accounts other than accounts 190 or 281-284 for the recording of deferred income tax expense(s).

Other Utility	Total Utility	Other Income	Total Company	Line No.
				1
	578,288,766	7,186,893	585,475,659	2
	12,516,230		12,516,230	3
	1,504,670,071	373,846	1,505,043,917	4
	353,520,070	8,915,400	362,435,470	5
				6
		(3,779,113)		7
0	**2,448,995,137**			8
		12,697,026		9
				10
	267,813,216	4,689,633	272,502,849	11
	12,490,883		12,490,883	12
	1,470,416,556	428,119	1,470,844,675	13
	737,273,706	13,154,661	750,428,367	14
				15
		(7,643,924)		16
0	**2,487,994,361**			17
		10,628,489		18
				19
				20
	(4,686,927)		(4,686,927)	21
				22
				23
				24
0	**(4,686,927)**	**0**		25
		0		26
		0		27

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 2018/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		1,194,391,223	1,133,421,900
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Record the Implementation of ASU 2018-02		310,572	
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		310,572	
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		261,045,904	186,357,865
17	Appropriations of Retained Earnings (Acct. 436)			
18	Reclassification of Appropriated Retained Earnings-Amort Reserve Federal		-125,237	(388,542)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-125,237	(388,542)
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			-124,750,000	(125,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-124,750,000	(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)		1,330,872,462	1,194,391,223
	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 2018/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)		4,289,459	4,164,222
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		4,289,459	4,164,222
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,335,161,921	1,198,555,445
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-6,289,416	(6,674,314)
50	Equity in Earnings for Year (Credit) (Account 418.1)		255,753	384,898
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		-6,033,663	(6,289,416)

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 2018/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)	261,301,657	186,742,763
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	293,061,364	210,648,257
5	Amortization of Regulatory Debits and Credits	29,418	295,199
6	Amortization of Nuclear Fuel	118,713,831	132,854,010
7	Accretion of Asset Retirement Obligations	7,302,976	8,248,773
8	Deferred Income Taxes (Net)	-42,905,508	201,024,131
9	Investment Tax Credit Adjustment (Net)	-4,686,927	-4,705,788
10	Net (Increase) Decrease in Receivables	1,574,226	4,598,145
11	Net (Increase) Decrease in Inventory	-12,771,213	-8,868,653
12	Net (Increase) Decrease in Allowances Inventory	1,562,362	1,360,114
13	Net Increase (Decrease) in Payables and Accrued Expenses	30,314,074	3,650,671
14	Net (Increase) Decrease in Other Regulatory Assets	85,505,267	-25,158,551
15	Net Increase (Decrease) in Other Regulatory Liabilities	18,952,582	-11,123,531
16	(Less) Allowance for Other Funds Used During Construction	11,901,253	11,055,694
17	(Less) Undistributed Earnings from Subsidiary Companies	255,753	384,898
18	Other (provide details in footnote):	-133,210,101	-86,376,793
19	Mark-to-Market of Risk Management Contracts	-4,093,754	-2,269,195
20	Pension Contributions to Qualified Plant Trust		-12,975,000
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	608,493,248	586,503,960
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-579,330,045	-657,452,440
27	Gross Additions to Nuclear Fuel	-47,045,636	-109,502,938
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-135,379	-386,031
30	(Less) Allowance for Other Funds Used During Construction	-11,901,253	-11,055,694
31	Other (provide details in footnote):		
32			
33	Acquired Assets	-1,229,471	-1,306,503
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-615,839,278	-757,592,218
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	11,276,095	5,172,564
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)	-2,064,731,986	-2,300,540,331
45	Proceeds from Sales of Investment Securities (a)	2,010,007,164	2,256,276,264

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		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):	4,795,579	5,958,730
54	(Increase)/Decrease in Other Special Deposits	-408,143	-56,704
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-654,900,569	-790,781,695
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	1,125,000,000	467,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Long Term Debt Issuance Costs	-12,357,202	-6,396,577
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68	Proceeds on Capital Leaseback	56,981,222	896,322
69	Fee on early retirement of long-term debt	-10,343,889	
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,159,280,131	461,499,745
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-776,578,237	-128,486,550
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Notes Payable to Associated Companies	-210,511,038	-3,626,344
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-124,750,000	-125,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	47,440,856	204,386,851
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	1,033,535	109,116
87			
88	Cash and Cash Equivalents at Beginning of Period	1,329,955	1,220,839
89			
90	Cash and Cash Equivalents at End of period	2,363,490	1,329,955

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

		2018 Cash Flow Incr / (Decr)		2017 Cash Flow Incr / (Decr)
Utility Plant, Net (Includes Purchases of Nuclear Fuel)	$	(180,296,132)	$	(117,619,185)
Property and Investments, Net		2,250,232		(3,195,239)
Margin Deposits		(4,109,196)		349,199
Prepayments		(10,955,972)		4,663,274
Accrued Utility Revenues, Net		3,722,582		(5,824,264)
Miscellaneous Current and Accr Assets		(7,760,470)		11,673,129
Unamortized Debt Expense		1,248,701		1,407,442
Other Deferred Debits, Net		4,287,981		(8,000,871)
Other Comprehensive Income, Net		(698,276)		1,318,349
Unamortized Discount/Premium on Long-Term Debt		746,833		554,114
Accumulated Provisions - Misc		13,775,100		6,561,401
Current and Accrued Liabilities, Net		(8,084,965)		(20,397,221)
Other Deferred Credits, Net		52,663,481		42,133,079
Total	**$**	**(133,210,101)**	**$**	**(86,376,793)**

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

		2018 Cash Flow Incr / (Decr)		2017 Cash Flow Incr / (Decr)
Meter Sales - Affiliated Companies	$	106,951	$	213,963
Transformer Sales - Affiliated Companies		690,089		610,550
Transco Transfer of Assets		7,288,411		4,167,583
One (1) McGraw-Edison transformer, serial no. C-05004-5-1		102,551		-
Sale of motor vessel Gale Rhodes		435,000		-
Land Sale of 4,055.33+/- acres Catahoula Parish, LA		336,493		-
Sale of the M/V Boonesboro		250,000		-
Sale of 2017 Outage Scrap Metal		-		180,468
Land sale proceeds via incoming wire transfer from Hendrich Title for the sale of 1048+/- acres in Sullivan County, Indiana to IDNR		2,066,600		-
Total	**$**	**11,276,095**	**$**	**5,172,564**

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

		2018 Cash Flow Incr / (Decr)		2017 Cash Flow Incr / (Decr)
DOE Settlement	$	2,877,125	$	1,900,856
CIAC Proceeds		1,535,901		4,057,874
Insurance Proceeds		382,553		-
Total	**$**	**4,795,579**	**$**	**5,958,730**

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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.
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.
ARAM	Average Rate Assumption Method, an IRS approved method used to calculate the reversal of Excess ADIT for ratemaking purposes.
ARO	Asset Retirement Obligations.
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 VII, DCC Fuel VIII, DCC Fuel IX, DCC Fuel X, DCC Fuel XI and DCC Fuel XII entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DOE	U. S. Department of Energy.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
Excess ADIT	Excess accumulated deferred income taxes.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.

FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
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	Kilowatt-hour.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
NO_X	Nitrogen oxide.
NRC	Nuclear Regulatory Commission.
NSR	New Source Review.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefits.
OTC	Over the counter.
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.
ROE	Return on Equity.
RPM	Reliability Pricing Model.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SCR	Selective Catalytic Reduction, NO_X reduction technology at Rockport Plant.
SEC	U.S. Securities and Exchange Commission.
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.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SSO	Standard service offer.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TA	Transmission Agreement.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the “Tax Cuts and Jobs Act” (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
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 596,000 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.

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

The FERC also approved a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement that amongst other things addresses the treatment of purchases and sales made by AEPSC on behalf of the member companies that extend beyond termination of the Interconnection Agreement.

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. 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 UPAs 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 generally accruing to the benefit of APCo, I&M, KPCo and WPCo. 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 MPSC regulate all of the retail distribution operations and rates of I&M's retail public utility subsidiaries on a cost basis. They also regulate the retail generation/power supply operations and rates.

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

In addition, the FERC regulates the SIA and TA, 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 14 - Related Party Transactions for additional information.

Basis of Accounting

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

- Accounting for subsidiaries on an equity basis.
- The classification of deferred fuel as noncurrent rather than current.
- The 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.
- The classification of Non-Service Cost Components of Net Periodic Benefit Cost as Operating Expense instead of Other Income (Expense).

Accounting for the Effects of Cost-Based Regulation

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

Use of Estimates

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

Cash and Cash Equivalents

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

Supplementary Information

	2018	2017
For the Years Ended December 31,	**(in millions)**	
Cash was Paid (Received) for:		
Interest (Net of Capitalized Amounts)	$ 112.0	$ 91.1
Income Taxes (Net of Refunds)	32.5	(89.9)
Noncash Acquisitions Under Capital Leases	61.3	76.6
As of December 31,		
Construction Expenditures Included in Current and Accrued Liabilities	93.0	88.5
Acquisition of Nuclear Fuel Included in Current and Accrued Liabilities	4.0	—
Expected Reimbursement for Capital Cost of SNF Dry Cask Storage	2.2	2.6

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

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, through purchase agreements with I&M. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from bank conduits for the interest in the billed and unbilled receivables they acquire from affiliated utility subsidiaries. See “Securitized Accounts Receivable – AEP Credit” section of Note 13 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, 2018.

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

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.

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

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed or is not probable, the cost of that asset shall be 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.

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

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Operation Expenses when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily using the units-of-production method. Fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the IURC's and the MPSC's reviews and approvals. The amount of an over-recovery or under-recovery can also be affected by actions of the IURC and the MPSC. On a routine basis, the IURC and the MPSC 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 or alternative revenues recognized in accordance with the guidance for "Regulated Operations") and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching revenue with its passage to customers in cost-based regulated rates.

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

Retail and Wholesale Supply and Delivery of Electricity

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

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

Gross versus Net Presentation of Certain Electricity Supply and Delivery Activities

Most of the power produced at the generation plants is sold to PJM. I&M also purchases power from PJM to supply power to customers. 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 from marketing and risk management transactions that are not derivatives as the performance obligation of delivering the commodity is satisfied. Expenses from marketing and risk management transactions that are not derivatives are also recognized upon delivery of the commodity.

I&M uses MTM accounting for marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or elected normal under the normal purchase normal sale election. 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). In the event I&M designates a cash flow hedge, the cash flow hedge's gain or loss is initially recorded as a component of AOCI. When the forecasted transaction is realized and affects net income, I&M subsequently reclassifies the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on their statements of income. See "Accounting for Cash Flow Hedging Strategies" section of Note 9.

Levelization of Nuclear Refueling Outage Costs

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

Maintenance

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

Income Taxes and Investment Tax Credits (ITC)

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 11 - Income Taxes 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.

I&M applies the deferral methodology for the recognition of ITC. Deferred ITC is amortized to income tax expense over the life of the asset that generated the credit. Amortization of deferred ITC begins when the asset is placed in-service, except where the IURC and the MPSC reflect 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 on the statements of income.

Excise Taxes

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

Debt

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

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

Pension and OPEB Plans

I&M participates in an AEP sponsored qualified pension plan and 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 7 -Benefit Plans for additional information including significant accounting policies associated with the plans.

Investments Held in Trust for Future Liabilities

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

Benefit Plans

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

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

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

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

Pension Plan Assets	Target
Equity	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. As of December 31, 2018 and 2017, the fair value of securities on loan as part of the program was $241 million and $492 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2018 and 2017.

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

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

Nuclear Trust Funds

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

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

I&M maintains trust funds for each regulatory jurisdiction. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by 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. With the adoption of ASU 2016-01, effective January 2018, available for sale classification only applies to investment in debt securities. Additionally, the adoption of ASU 2016-01 required changes in fair value of equity securities to be recognized in earnings. However, due to the regulatory treatment described below, this is not applicable for I&M's trust fund securities.

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

Comprehensive Income (Loss)

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

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2018 through February 21, 2019, the date that AEP's Form 10-K was issued, and has updated such evaluation for disclosure purposes through April 11, 2019. 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 with a customer, 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 flows arising from contracts with customers.

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. In that regard, the application of the new standard did not cause any significant differences in any individual financial statement line items had those line items been presented in accordance with the guidance that was in effect prior to the adoption of the new standard. Further, given the lack of material impact to the financial statements, the adoption of the new standard did not give rise to any material changes in I&M's previously established accounting policies for revenue. See Note 16 - Revenue from Contracts with Customers for additional disclosures required by the new standard.

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 sheets 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.

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 resulted in no impact to the 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 sheets 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 sheets. Additionally, a capital lease will be known as a finance lease going forward. Leases with 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.

New leasing standard implementation activities included the identification of the lease population within the AEP System as well as the sampling of representative lease contracts to analyze accounting treatment under the new accounting guidance. Based upon the completed assessments, management also prepared a gap analysis to outline new disclosure compliance requirements.

Management adopted ASU 2016-02 effective January 1, 2019 by means of a cumulative-effect adjustment to the balance sheets. Management elected 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.
Existing and expired land easements not previously accounted for as leases	Elect optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current leases guidance in Topic 840.
Cumulative-effect adjustment in the period of adoption	Elect the optional transition practical expedient to adopt the new lease requirements through a cumulative-effect adjustment on the balance sheet in the period of adoption.

Management concluded that the result of adoption would not materially change the volume of contracts that qualify as leases going forward. The adoption of the new standard did not materially impact results of operations or cash flows, but did have a material impact on the balance sheets. An impact of $351 million to I&M's balance sheets has been estimated for the first quarter of 2019.

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 and related implementation guidance effective January 1, 2020.

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 on 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 is eligible for capitalization as applicable following labor. 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 of the new standard 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 to reduce the complexity of applying hedge accounting. Among other things, ASU 2017-12: (a) expands the types of transactions eligible for hedge accounting, (b) eliminates the separate measurement and presentation of hedge ineffectiveness, (c) simplifies the requirements for assessments of hedge effectiveness, (d) provides companies more time to finalize hedge documentation and (e) enhances presentation and disclosure requirements.

Management early adopted ASU 2017-12 in the second quarter of 2018, effective January 1, 2018. The adoption of ASU 2017-12 resulted in no impact to results of operations, financial position or cash flows. The adoption of the new standard did not give rise to any material changes to I&M's previously established accounting policies for derivatives and hedging.

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. The accounting guidance for "Income Taxes" requires deferred tax assets and liabilities to be adjusted for the effect of a change in tax law or rates with the effect included in income from continuing operations in the reporting period that includes the enactment date of the tax change. 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 would not reflect the newly enacted corporate tax rate.

Management adopted ASU 2018-02 effective January 1, 2018, electing to reclassify the effects of the change in the federal corporate tax rate due to Tax Reform from AOCI to Retained Earnings. The portion of the one-time reclassification to Retained Earnings was recorded to FERC Account 439, Adjustments to Retained Earnings. A request was made in November 2018 for use of Account 439 and in January 2019 the FERC approved the request. The adoption of the ASU and the use of Account 439 had an insignificant effect on I&M's rates charged to customers. Additionally, a portion of the reclassification was recorded to Other Regulatory Liabilities to adjust the tax effects of certain interest rate hedges that were previously deferred as a part of the accounting for Tax Reform. There were no other effects from Tax Reform that impacted AOCI. Management applied the new guidance at the beginning of the period of adoption. The adoption of the new standard did not have a material impact on the statement of financial position and did not impact results of operations or cash flows.

ASU 2018-14 "Disclosure Framework: Changes to the Disclosure Requirements for Defined Benefit Plans" (ASU 2018-14)

In August 2018, the FASB issued ASU 2018-14 modifying the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. The amendments remove disclosures that no longer are considered cost beneficial, clarify the specific requirements of disclosures and add disclosure requirements identified as relevant.

Management early adopted ASU 2018-14 for the 2018 Annual Report and applied the new standard for all periods presented. As a result of adoption, I&M's disclosures were updated as follows:

- Amended the disclosure to remove the amounts in AOCI expected to be recognized as components of net periodic benefit cost over the next fiscal year.
- Amended the disclosure to remove the effects of a one-percentage-point change in assumed health care cost trend rates on the (a) aggregate of the service and interest cost components of net periodic benefit costs and (b) benefit obligation for postretirement health care benefits.
- Amended the disclosure to include the weighted-average interest crediting rates for cash balance plans and other plans with promised interest crediting rates.
- Amended the disclosure to include an explanation of the reasons for significant gains and losses related to changes in the benefit obligation for the period.

See Note 7 - Benefit Plans for updates to the disclosures required by the new standard.

ASU 2018-15 "Internal-Use Software: Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract" (ASU 2018-15)

In August 2018, the FASB issued ASU 2018-15 aligning the requirements for capitalizing implementation costs incurred in a cloud computing arrangement (hosting arrangement) that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The new standard requires an entity (customer) in a hosting arrangement that is a service contract to follow the accounting guidance for "Internal-Use Software" to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. To eliminate diversity in practice, the new standard changes the presentation of implementation costs for cloud service arrangements that are service contracts without the purchase of a license. Implementation costs for cloud service contracts will be presented on the balance sheets in the same manner as a prepayment. I&M currently presents implementation costs in Utility Plant on the balance sheets. Under the new standard, amortization of capitalized implementation costs of a hosting arrangement will be recorded in Operation Expenses and Maintenance Expenses over the term of the cloud service arrangement, rather than Depreciation Expense on the statements of income. Payments for capitalized implementation costs in the statement of cash flows will be classified in the same manner as payments made for fees associated with the hosting element.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2019, with early adoption permitted. Management is analyzing the impact of this new standard and at this time, cannot estimate the impact of adoption on results of operations, financial position or cash flows. Management plans to adopt ASU 2018-15 prospectively, effective January 1, 2020.

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, 2018 and 2017. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 7 - Benefit Plans for additional details.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2018

		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, 2017	$ (10.7)	$ 5.1	$ (6.5)	$ (12.1)
Change in Fair Value Recognized in AOCI	—	—	(0.6)	(0.6)
Amount of (Gain) Loss Reclassified from AOCI				
Interest on Long-Term Debt (a)	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) Benefit	2.0	—	—	2.0
Income Tax (Expense) Benefit	0.4	—	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.6	—	—	1.6
Net Current Period Other Comprehensive Income (Loss)	1.6	—	(0.6)	1.0
ASU 2018-02 Adoption (b)	(2.4)	—	(0.3)	(2.7)
Balance in AOCI as of December 31, 2018	$ (11.5)	$ 5.1	$ (7.4)	$ (13.8)

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 (a)	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) Benefit	2.0	—	—	2.0
Income Tax (Expense) Benefit	0.7	—	—	0.7
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	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)

(a) Amounts reclassified to the referenced line item on the statements of income.
(b) See Note 2 - New Accounting Pronouncements for additional information.

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 impacts outstanding rate and regulatory matters. For additional details on the impact of Tax Reform, see Note 11 - Income Taxes.

2017 Indiana Base Rate Case

In 2017, I&M filed a request with the IURC for a $263 million annual increase in Indiana rates based upon a proposed 10.6% ROE. In February 2018, I&M filed a Stipulation and Settlement Agreement for a $97 million annual increase, based on a 9.95% ROE, 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. In May 2018, the IURC issued an order approving the Stipulation and Settlement Agreement.

2017 Michigan Base Rate Case

In 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% ROE. In February 2018, an MPSC ALJ issued a Proposal for Decision and recommended an annual revenue increase of $49 million, including an intervenor's proposal for up to 10% of I&M's Michigan retail customers to choose an alternate supplier for generation and a proposed capacity rate based on PJM's net cost of new entry value of $289/MW-day, as well as the MPSC staff's recommended calculation of depreciation expense for both units of Rockport Plant through 2028 and a ROE of 9.8%. In April 2018, the MPSC issued an order that generally approved the ALJ proposal resulting in an annual revenue increase of $50 million, effective April 2018 based on a 9.9% ROE. The MPSC also approved the ALJ's recommendation related to the capacity rate.

If the maximum 10% of customers choose an alternate supplier starting in February 2019, the estimated annual pretax loss due to the reduced capacity rate would be approximately $9 million. In October 2018, I&M filed a request with the MPSC seeking authority to defer costs related to customers choosing an alternate supplier starting in February 2019. In December 2018, the MPSC rejected I&M's request.

Michigan Tax Reform

In August 2018, the MPSC approved I&M's application to refund, through a rider, approximately $9 million annually for the impact of Tax Reform on I&M's Michigan jurisdictional earnings effective September 1, 2018. In October 2018, I&M also made two filings with the MPSC recommending to: (a) refund $3 million over eight months for the impact of Tax Reform on Michigan jurisdictional earnings for the period April 26, 2018 through August 31, 2018, (b) refund approximately $68 million of Excess ADIT associated with certain depreciable property using ARAM and (c) refund approximately $37 million of Excess ADIT that is not subject to rate normalization requirements over 10 years. In January 2019, I&M received an order from the MPSC requiring I&M to refund $5 million over six months, effective February 2019, for the Michigan jurisdictional impacts of Tax Reform related to the period January 1, 2018 through August 31, 2018. An order from the MPSC regarding Excess ADIT is expected in the first half of 2019.

Rockport Plant, Unit 2 SCR

In 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. 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 and is expected to be placed in service in May 2020. The estimated cost of the SCR project is $274 million, excluding AFUDC, to be shared equally between I&M and AEGCo. The filing included a request for authorization for I&M to defer and recover, through a rider, its Indiana jurisdictional ownership share of costs including investment carrying costs at a weighted-average cost of capital, depreciation over a 10-year period as provided by statute and other related expenses.

In March 2018, the IURC issued an order approving: (a) the CPCN, (b) the $274 million estimated cost of the SCR, excluding AFUDC, (c) deferral of the Indiana jurisdictional ownership share of costs, including investment carrying costs, (d) depreciation of the SCR asset over 10 years and (e) recovery of these costs using an I&M Indiana rider. Management intends to request recovery of the Michigan jurisdictional share of the SCR project in a future base rate case. If the Michigan jurisdictional share of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. The AEGCo ownership share of the SCR project will be billable under the Rockport UPA to I&M and KPCo and will be subject to future regulatory approval for recovery.

PJM Transmission Rates

In 2016, PJM transmission owners 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 May 2018, the FERC approved the settlement agreement. PJM implemented a transmission enhancement charge adjustment through the PJM OATT, which will be billable through 2025. Management expects that any refunds received would generally be returned to retail customers through existing state rider mechanisms and has recorded $29 million to Customer Accounts Receivable with offsets to Other Regulatory Liabilities as of December 31, 2018.

FERC Transmission Complaint

In 2016, seven parties filed a complaint at the FERC that alleged the base ROE used by AEP's transmission owning subsidiaries within PJM 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 2017, a FERC order set the matter for hearing and settlement procedures. In March 2018, AEP's transmission owning subsidiaries within PJM 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 transmission owning subsidiaries within PJM of 9.85% (10.35% inclusive of the RTO incentive adder of 0.5%), effective January 1, 2018, (b) requires AEP's transmission owning subsidiaries within PJM to provide a one-time refund of $50 million, attributable from the date of the complaint through December 31, 2017, which was 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 transmission owning subsidiaries within PJM also filed updated transmission formula rates incorporating the reduction in the corporate federal income tax rate due to Tax Reform, effective January 1, 2018 and providing for the amortization of the portion of the Excess ADIT that is 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. In April 2018, an ALJ accepted the interim settlement rates, which included the $50 million one-time refund that occurred in the second quarter of 2018. These interim rates are subject to refund or surcharge, with interest.

In April 2018, certain intervenors filed comments at the FERC recommending a base ROE of 8.48% and a one-time refund of $184 million. The FERC trial staff filed comments recommending a base ROE of 8.41% and a one-time refund of $175 million. Another intervenor recommended the refund be calculated in accordance with the base ROE that will ultimately be approved by the FERC. In May 2018, management filed reply comments providing further support for the 9.85% base ROE agreed to in the settlement agreement. In February 2019, the FERC issued an order that requested additional information in order to evaluate the settlement. That order did not rule on the merits of the settlement.
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.

Modifications to AEP's PJM Transmission Rates

In 2016, AEP's transmission owning subsidiaries within PJM 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. The modified PJM OATT formula rates are based on projected calendar year financial activity and projected plant balances. In 2017, AEP's transmission owning subsidiaries within PJM filed an uncontested settlement agreement with the FERC resolving all outstanding issues. In April 2018, the FERC approved the uncontested settlement agreement and rates were implemented effective January 1, 2018.

5. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	December 31, 2018	December 31, 2017	Remaining Recovery Period
	(in millions)		
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Cook Plant Uprate Project	$ —	$ 36.3	
Cook Plant Turbine	—	15.9	
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	—	14.7	
Rockport Plant Dry Sorbent Injection System - Indiana	—	10.4	
Other Regulatory Assets Pending Final Regulatory Approval	3.3	2.0	
Total Regulatory Assets Pending Final Regulatory Approval	3.3	79.3	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Cook Plant Uprate Project	35.0	—	15 years
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	16.1	—	16 years
Cook Plant Turbine	15.8	—	20 years
Rockport Plant Dry Sorbent Injection System - Indiana	11.5	—	9 years
Cook Plant, Unit 2 Baffle Bolts - Indiana	5.7	6.0	20 years
Under-recovered Fuel Costs	—	14.9	
Other Regulatory Assets Approved for Recovery	2.4	1.0	various
Total Regulatory Assets Currently Earning a Return	86.5	21.9	
Regulatory Assets Currently Not Earning a Return			
Income Taxes Subject to Flow Through	285.5	263.9	26 years
Pension and OPEB Funded Status	84.9	77.8	12 years
Cook Plant Nuclear Refueling Outage Levelization	37.5	66.7	3 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	20.1	57.0	2 years
Postemployment Benefits	6.5	9.7	4 years
Medicare Subsidy	6.1	7.1	6 years
Unamortized Loss on Reacquired Debt	0.8	1.0	30 years
Other Regulatory Assets Approved for Recovery	16.8	20.0	various
Total Regulatory Assets Currently Not Earning a Return	458.2	503.2	

Total Regulatory Assets Approved for Recovery	544.7	525.1	
Total FERC Account 182.3 Regulatory Assets	$ 548.0	$ 604.4	

Regulatory Liabilities:	**December 31, 2018**	**2017**	**Remaining Recovery Period**
	(in millions)		
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	$ 125.0	$ 534.6	
Excess ADIT that is Not Subject to Rate Normalization Requirements	40.6	193.0	
Total Regulatory Liabilities Pending Final Regulatory Determination	165.6	727.6	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Over-recovered Fuel Costs - Michigan	4.5	—	1 year
Total Regulatory Liabilities Currently Paying a Return	4.5	—	
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	828.5	945.0	(b)
Spent Nuclear Fuel	42.9	43.2	(b)
PJM Transmission Enhancement Refund	29.1	—	7 years
Over-recovered Fuel Costs -Indiana	22.9	2.7	1 year
Other Regulatory Liabilities Approved for Payment	24.0	11.4	various
Total Regulatory Liabilities Currently Not Paying a Return	947.4	1,002.3	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	359.4	—	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	191.4	—	10 years
Income Taxes Subject to Flow Through	7.2	9.0	26 years
Total Income Tax Related Regulatory Liabilities	558.0	9.0	
Total Regulatory Liabilities Approved for Payment	1,509.9	1,011.3	
Total FERC 254 Account Regulatory Liabilities	$ 1,675.5	$ 1,738.9	

(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. See "Federal Tax Reform" section of Note 11 for additional information.
(b) Relieved when plant is decommissioned.
(c) Refunded using ARAM.

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, 2018:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 251.4	$ 293.1	$ 187.8	$ 83.8	$ 816.1
Energy and Capacity Purchase Contracts	126.8	264.0	166.4	322.3	879.5
Total	$ 378.2	$ 557.1	$ 354.2	$ 406.1	$ 1,695.6

(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, 2018, 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 equipment under master lease agreements. See “Master Lease Agreements” and “Railcar Lease” sections of Note 12 for additional information.

ENVIRONMENTAL CONTINGENCIES

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

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

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. There are three sites for which I&M received information requests which could lead to a Potentially Responsible Party (PRP) designation. I&M has also been named potentially liable at two sites under state law including the 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. The remediation work was completed in 2018 in accordance with a plan approved by MDEQ with no significant effects on net income.

Management evaluates the potential liability for each Superfund site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often non-hazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. As of December 31, 2018, management’s estimates do not anticipate material clean-up costs for identified Superfund sites.

NUCLEAR CONTINGENCIES

I&M owns and operates the two-unit 2,278 MW Cook Plant under licenses granted by the NRC. I&M has a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generation units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial.

Decommissioning and Low-Level Waste Accumulation Disposal

The costs to decommission a nuclear plant are affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of Cook Plant. The most recent decommissioning cost study was performed in 2018. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste was $2 billion in 2018 non-discounted dollars, with additional ongoing costs of $6 million per year for post decommissioning storage of SNF and an eventual cost of $37 million for the subsequent decommissioning of the SNF storage facility, also in 2018 non-discounted dollars. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were $8 million and $9 million for the years ended December 31, 2018 and 2017, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2018 and 2017, the total decommissioning trust fund balances were $2.2 billion and $2.2 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including unrealized gains and losses, interest and trust funds expenses) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to 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.

Spent Nuclear Fuel Disposal

The federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one-mill per KWh for fuel consumed after April 6, 1983 at the Cook Plant was collected from customers and remitted to the DOE through May 14, 2014. In May 2014, pursuant to court order from the U.S Court of Appeals for the District of Columbia Circuit, the DOE adjusted the fee to $0. As of December 31, 2018 and 2017, fees and related interest of $274 million and $269 million, respectively, for fuel consumed prior to April 7, 1983 were recorded as Other Long-term Debt and funds collected from customers along with related earnings totaling $317 million and $312 million, respectively, to pay the fee were recorded as part of Other Special Funds on the balance sheets. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

In 2011, I&M signed a settlement agreement with the federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government's delay in accepting SNF for permanent storage. Under the settlement agreement, I&M received $11 million and $22 million in 2018 and 2017, 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, 2018 and 2017, I&M deferred $8 million and $11 million, respectively, in Miscellaneous Current and Accrued Assets and $23 million and $5 million, respectively, in Miscellaneous Deferred Debits on the balance sheets for dry cask storage and related operation and maintenance costs for recovery under this agreement. See "Fair Value Measurements of Trust Assets for Decommissioning and Spent Nuclear Fuel Disposal" section of Note 10 for additional information.

Nuclear Insurance

I&M carries nuclear property insurance of $2.7 billion to cover an incident at Cook Plant including coverage for decontamination and stabilization, as well as premature decommissioning caused by an extraordinary incident. Insurance coverage for a nonnuclear property incident at 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 $50 million for I&M, which is assessable if the insurer's financial resources would be inadequate to pay for industry losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public nuclear liability arising from a nuclear incident of $14.1 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 $276 million per nuclear incident on Cook Plant's reactors payable in annual installments of $41 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 $13.6 billion would be covered by claim premium assessments made under the Price-Anderson Act. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds, I&M would seek recovery of those amounts from customers through a rate increase. If recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

I&M maintains insurance coverage normal and customary for electric utilities, subject to various deductibles. I&M also maintains property and casualty insurance that may cover certain physical damage or third-party injuries caused by 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 above for additional information.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to a 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 the U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it would 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, refueling or retirement of the unit. 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.

AEGCo and I&M sought and were granted dismissal of certain of the plaintiffs' claims, including claims for compensatory damages, breach of contract, breach of the implied covenant of good faith and fair dealing and indemnification of costs. Plaintiffs voluntarily dismissed the surviving claims that AEGCo and I&M failed to exercise prudent utility practices with prejudice, and the court issued a final judgment. The plaintiffs subsequently filed an appeal in the U.S. Court of Appeals for the Sixth Circuit.

The U.S. Court of Appeals for the Sixth Circuit issued an opinion and judgment affirming the district court's dismissal of the owners' breach of good faith and fair dealing claim as duplicative of the breach of contract claims, reversing the district court's dismissal of the breach of contract claims, and remanding the case for further proceedings.

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. Responsive and supplemental filings have been made by all parties. 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. In September 2018, the district court granted AEP's unopposed motion to stay further proceedings regarding the consent decree to facilitate settlement discussions among the parties to the consent decree. See "Proposed Modification of the NSR Litigation Consent Decree" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information.

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. 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 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,			
Assumption	2018	2017	2018	2017

Discount Rate	4.30%	3.65%	4.30%	3.60%
Interest Crediting Rate	4.00%	4.00%	NA	NA
Rate of Compensation Increase	4.90% (a)	4.85% (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 2018, 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,			
Assumption	**2018**	**2017**	**2018**	**2017**
Discount Rate	3.65%	4.05%	3.60%	4.10%
Interest Crediting Rate	4.00%	4.00%	NA	NA
Expected Return on Plan Assets	6.00%	6.00%	6.00%	6.75%
Rate of Compensation Increase	4.90% (a)	4.85% (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	**2018**	**2017**
Initial	6.25 %	6.50 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2024	2024

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, 2018, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

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

For the year ended December 31, 2018, the pension and OPEB plans had an actuarial gain due to an increase in the discount rate as well as updated estimates for future medical expenses in the OPEB plans. For the year ended December 31, 2017, the pension plans had an actuarial loss due to a decrease in the discount rate. The OPEB plans had an actuarial gain primarily due to a change in medical benefits for retirees which was partially offset by a decrease in the discount rate.

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

	Pension Plans		OPEB	
	2018	2017	2018	2017
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 624.3	$ 611.6	$ 153.5	$ 167.6
Service Cost	13.6	14.0	1.6	1.6
Interest Cost	22.1	24.3	5.4	6.9
Actuarial (Gain) Loss	(53.9)	10.8	(10.6)	(12.0)
Benefit Payments	(39.1)	(36.4)	(16.2)	(15.6)
Participant Contributions	—	—	4.5	4.9
Medicare Subsidy	—	—	0.1	0.1
Benefit Obligation as of December 31,	$ 567.0	$ 624.3	$ 138.3	$ 153.5
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 636.7	$ 586.1	$ 211.1	$ 186.6
Actual Gain (Loss) on Plan Assets	(13.8)	74.0	(12.1)	35.2
Company Contributions	—	13.0	—	—
Participant Contributions	—	—	4.5	4.9
Benefit Payments	(39.1)	(36.4)	(16.2)	(15.6)
Fair Value of Plan Assets as of December 31,	$ 583.8	$ 636.7	$ 187.3	$ 211.1
Funded Status as of December 31,	$ 16.8	$ 12.4	$ 49.0	$ 57.6

	Pension Plans		OPEB	
	December 31,			
	2018	2017	2018	2017
	(in millions)			
Special Funds – Prepaid Benefit Costs	$ 18.0	$ 13.4	$ 49.0	$ 57.6
Accumulated Provision for Pensions and Benefits – Long-term Benefit Liability	(1.2)	(1.0)	—	—
Funded Status	$ 16.8	$ 12.4	$ 49.0	$ 57.6

Amounts Included in Regulatory Assets, Deferred Income Taxes, AOCI and Income Tax Expense

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

	Pension Plans		OPEB	
	December 31,			
	2018	2017	2018	2017
Components	(in millions)			
Net Actuarial Loss	$ 80.6	$ 94.9	$ 54.7	$ 42.0
Prior Service Credit	—	—	(47.4)	(56.9)
Recorded as				
Regulatory Assets	$ 78.4	$ 91.8	$ 6.5	$ (14.0)
Deferred Income Taxes	0.5	0.7	0.2	(0.2)
Net of Tax AOCI	1.7	2.0	0.6	(0.6)
Income Tax Expense (a)	—	0.4	—	(0.1)

	Pension Plans		OPEB	
	2018	2017	2018	2017
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ (4.5)	$ (28.6)	$ 13.9	$ (34.9)
Amortization of Actuarial Loss	(9.8)	(9.7)	(1.2)	(4.4)
Amortization of Prior Service Credit (Cost)	—	(0.2)	9.5	9.4
Change for the Year Ended December 31,	$ (14.3)	$ (38.5)	$ 22.2	$ (29.9)

(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.

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,			
2018	2017	2018	2017
12.4 %	12.3 %	12.2 %	12.2 %

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2018:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 277.3	$ —	$ —	$ —	$ 277.3	5.9 %
International	384.1	—	—	—	384.1	8.2 %
Options	—	18.3	—	—	18.3	0.4 %
Common Collective Trusts (c)	—	—	—	370.1	370.1	7.9 %
Subtotal – Equities	661.4	18.3	—	370.1	1,049.8	22.4 %
Fixed Income (a):						
United States Government and Agency Securities	0.2	1,512.5	—	—	1,512.7	32.2 %
Corporate Debt	—	1,082.9	—	—	1,082.9	23.0 %
Foreign Debt	—	221.6	—	—	221.6	4.7 %
State and Local Government	—	28.2	—	—	28.2	0.6 %
Other – Asset Backed	—	7.4	—	—	7.4	0.2 %
Subtotal – Fixed Income	0.2	2,852.6	—	—	2,852.8	60.7 %
Infrastructure (c)	—	—	—	72.2	72.2	1.5 %
Real Estate (c)	—	—	—	220.4	220.4	4.7 %
Alternative Investments (c)	—	—	—	444.6	444.6	9.5 %
Cash and Cash Equivalents (c)	(0.4)	36.3	—	11.9	47.8	1.0 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	8.3	8.3	0.2 %
Total	$ 661.2	$ 2,907.2	$ —	$ 1,127.5	$ 4,695.9	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column 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 presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2018:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 233.3	$ —	$ —	$ —	$ 233.3	15.2 %
International	185.9	—	—	—	185.9	12.1 %
Options	—	4.3	—	—	4.3	0.3 %
Common Collective Trusts (b)	—	—	—	226.2	226.2	14.7 %
Subtotal – Equities	419.2	4.3	—	226.2	649.7	42.3 %
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	163.6	163.6	10.7 %
United States Government and Agency Securities	0.2	181.5	—	—	181.7	11.8 %
Corporate Debt	—	188.6	—	—	188.6	12.3 %
Foreign Debt	—	35.0	—	—	35.0	2.3 %
State and Local Government	41.8	11.8	—	—	53.6	3.5 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	42.0	417.1	—	163.6	622.7	40.6 %
Trust Owned Life Insurance:						
International Equities	—	49.4	—	—	49.4	3.2 %
United States Bonds	—	154.4	—	—	154.4	10.1 %
Subtotal – Trust Owned Life Insurance	—	203.8	—	—	203.8	13.3 %
Cash and Cash Equivalents (b)	54.4	—	—	4.8	59.2	3.9 %
Other – Pending Transactions and Accrued Income (a)	—	—	—	(1.2)	(1.2)	(0.1)%
Total	$ 515.6	$ 625.2	$ —	$ 393.4	$ 1,534.2	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, 2017:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
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 (a):						
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 %
Cash and Cash Equivalents (c)	0.4	35.6	—	21.2	57.2	1.1 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	22.7	22.7	0.5 %
Total	$ 826.7	$ 3,054.8	$ —	$ 1,292.6	$ 5,174.1	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column 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.

Accumulated Benefit Obligation

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

Accumulated Benefit Obligation	December 31, 2018	December 31, 2017
	(in millions)	
Qualified Pension Plan	$ 536.3	$ 592.4
Nonqualified Pension Plans	0.6	0.4
Total	$ 536.9	$ 592.8

Obligations in Excess of Fair Values

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

Projected Benefit Obligation

	December 31, 2018	December 31, 2017
	(in millions)	
Projected Benefit Obligation	$ 1.2	$ 1.0
Fair Value of Plan Assets	—	—
Underfunded Projected Benefit Obligation	$ (1.2)	$ (1.0)

Accumulated Benefit Obligation

	December 31, 2018	December 31, 2017
	(in millions)	
Accumulated Benefit Obligation	$ 0.6	$ 0.4
Fair Value of Plan Assets	—	—
Underfunded Accumulated Benefit Obligation	$ (0.6)	$ (0.4)

Estimated Future Benefit Payments and Contributions

I&M expects contributions and payments for the pension plans of $1 million during 2019. 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 the I&M's assets. The payments include the participants' contributions to the plan for their share of the cost. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results.

The estimated payments for the pension benefits and OPEB are as follows:

	Estimated Payments	
	Pension Plans	OPEB
	(in millions)	
2019	$ 36.2	$ 14.8
2020	36.4	15.4
2021	37.5	15.7
2022	38.9	15.7
2023	40.3	15.6
Years 2024 to 2028, in Total	210.6	75.6

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,			
	2018	2017	2018	2017
	(in millions)			
Service Cost	$ 13.6	$ 14.0	$ 1.6	$ 1.6
Interest Cost	22.1	24.3	5.4	6.9
Expected Return on Plan Assets	(35.7)	(34.6)	(12.3)	(12.2)
Amortization of Prior Service Cost (Credit)	—	0.2	(9.5)	(9.4)
Amortization of Net Actuarial Loss	9.8	9.7	1.2	4.4
Net Periodic Benefit Cost (Credit)	9.8	13.6	(13.6)	(8.7)
Capitalized Portion	(5.6)	(5.5)	(0.7)	3.5
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 4.2	$ 8.1	$ (14.3)	$ (5.2)

American Electric Power System Retirement Savings Plan

I&M participates in an AEP sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions to the retirement savings plans for the years ended December 31, 2018 and 2017 were $11 million and $11 million, respectively.

8. BUSINESS SEGMENTS

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

9. DERIVATIVES AND HEDGING

I&M adopted ASU 2017-12 in the second quarter of 2018, effective January 1, 2018. See Note 2 - New Accounting Pronouncements for additional information.

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, 2018	Volume December 31, 2017	Unit of Measure
	(in millions)		
Commodity:			
Power	40.9	38.5	MWhs
Coal	—	2.0	Tons
Natural Gas	2.3	0.7	MMBtus
Heating Oil and Gasoline	0.7	0.7	Gallons

Cash Flow Hedging Strategies

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

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

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 sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, 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 as of December 31, 2018 and 2017.

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

Fair Value of Derivative Instruments
December 31, 2018

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	$ 52.4	$ (43.2)	$ 9.2
Long-Term Portion of Derivative Instrument Assets	2.0	(1.4)	0.6
Derivative Instrument Liabilities	42.7	(42.3)	0.4
Long-Term Portion of Derivative Instrument Liabilities	1.6	(1.5)	0.1

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

(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) All derivative contracts subject to a master netting arrangement or similar agreement are offset in the statement of financial position.

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

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2018	2017
	(in millions)	
Operating Revenues	$ (8.2)	$ 5.3
Operation Expenses	1.2	0.8
Other Regulatory Assets (a)	7.1	(7.4)
Other Regulatory Liabilities (a)	11.6	15.9
Total Gain on Risk Management Contracts	$ 11.7	$ 14.6

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

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

The accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same 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 gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income on the balance sheets until the period the hedged item affects Net Income.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Operating Revenues or Operation Expenses on the statements of income or in Other Regulatory Assets or

Other Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During the years ended 2018 and 2017, I&M did not apply cash flow hedging to outstanding power derivatives.

I&M reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income on the balance sheets into Interest on Long Term Debt on the statements of income in those periods in which hedged interest payments occur. During the years ended 2018 and 2017, I&M did not apply cash flow hedging to outstanding interest rate derivatives.

The accumulated gains or losses related to 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 in qualifying foreign currency hedging relationships. During the years ended 2018 and 2017, I&M did not apply cash flow hedging to any outstanding foreign currency derivatives. 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 – Comprehensive Income.

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, 2018		December 31, 2017	
Interest Rate			
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)			
$ (11.5)	$ (1.6)	$ (10.7)	$ (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 credit agency ratings and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

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

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 no derivative contracts with collateral triggering events in a net liability position as of December 31, 2018 and 2017.

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 were immaterial for years ended December 31, 2018 and 2017.

10. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

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

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

December 31,			
2018		2017	
Book Value	Fair Value	Book Value	Fair Value
(in millions)			
$ 2,919.7	$ 2,934.4	$ 2,569.4	$ 2,826.1

Fair Value Measurements of Trust Assets for Decommissioning and Spent Nuclear Fuel 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,					
	2018			2017		
	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 22.5	$ —	$ —	$ 17.2	$ —	$ —
Fixed Income Securities:						
United States Government	996.1	26.7	(7.1)	981.2	29.7	(3.6)
Corporate Debt	52.4	1.1	(1.9)	58.7	3.8	(1.2)
State and Local Government	8.6	0.6	(0.2)	8.8	0.8	(0.2)

Subtotal Fixed Income Securities	1,057.1	28.4	(9.2)	1,048.7	34.3	(5.0)
Equity Securities – Domestic (a)	1,395.3	766.3	—	1,461.7	868.2	(75.5)
Other Special Funds	$ 2,474.9	$ 794.7	$ (9.2)	$ 2,527.6	$ 902.5	$ (80.5)

(a) Amount reported as Gross Unrealized Gains includes unrealized gains of $784 million and unrealized losses of $18 million. I&M adopted ASU 2016-01 during the first quarter of 2018. Due to the adoption of the ASU, Other-Than-Temporary Impairments are no longer applicable to Equity Securities with readily determinable fair values.

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

	Years Ended December 31, 2018	2017
	(in millions)	
Proceeds from Investment Sales	$ 2,010.0	$ 2,256.3
Purchases of Investments	2,064.7	2,300.5
Gross Realized Gains on Investment Sales	47.5	200.7
Gross Realized Losses on Investment Sales	32.8	146.0

The base cost of fixed income securities was $1 billion and $1 billion as of December 31, 2018 and 2017, respectively. The base cost of equity securities was $629 million and $594 million as of December 31, 2018 and 2017, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2018 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 359.4
After 1 year through 5 years	358.9
After 5 years through 10 years	176.1
After 10 years	162.7
Total	$ 1,057.1

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, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (b)	$ —	$ 42.1	$ 10.3	$ (43.2)	$ 9.2
Other Special Funds					
Cash and Cash Equivalents (c)	12.3	—	—	10.2	22.5
Fixed Income Securities:					
United States Government	—	996.1	—	—	996.1
Corporate Debt	—	52.4	—	—	52.4
State and Local Government	—	8.6	—	—	8.6
Subtotal Fixed Income Securities	—	1,057.1	—	—	1,057.1
Equity Securities – Domestic (d)	1,395.3	—	—	—	1,395.3
Total Other Special Funds	1,407.6	1,057.1	—	10.2	2,474.9
Total Assets	$ 1,407.6	$ 1,099.2	$ 10.3	$ (33.0)	$ 2,484.1

Liabilities:

Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 0.1	$ 41.2	$ 1.4	$ (42.3)	$ 0.4

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

(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, 2018 and 2017.
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, 2018	Derivative Instrument Assets (Liabilities)
	(in millions)
Balance as of December 31, 2017	$ 7.6
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	14.2
Settlements	(21.3)

Transfers out of Level 3 (c)	(0.3)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	8.7
Balance as of December 31, 2018	$ 8.9

Year Ended December 31, 2017	**Derivative Instrument 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

(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, 2018

	Fair Value		**Valuation**	**Significant Unobservable**	**Input/Range**		
	Assets	**Liabilities**	**Technique**	**Input (a)**	**Low**	**High**	**Weighted Average**
	(in millions)						
Energy Contracts	$ 1.4	$ 0.9	Discounted Cash Flow	Forward Market Price	$ 16.82	$ 62.65	$ 37.00
FTRs	8.9	0.5	Discounted Cash Flow	Forward Market Price	(2.11)	6.21	1.06
Total	$ 10.3	$ 1.4					

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					

(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, 2018 and 2017:

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)

11. INCOME TAXES

Federal Tax Reform and Legislation

In December 2017, Tax Reform legislation was signed into law. Tax Reform includes significant changes to the Internal Revenue Code of 1986, as amended, including lowering the corporate federal income tax rate from 35% to 21%. As a result of this rate change, I&M’s deferred tax assets and liabilities were remeasured using the newly enacted rate of 21% in December 2017. In response to Tax Reform, the SEC staff issued Staff Accounting Bulletin 118 (SAB 118) in December 2017. SAB 118 provided for up to a one year period (the measurement period) in which to complete the required analyses and accounting required by Tax Reform.

During 2017, I&M recorded provisional amounts for the income tax effects of Tax Reform. Throughout 2018, I&M continued to assess the impacts of legislative changes in the tax code as well as interpretative changes of the tax code. The measurement period adjustments recorded during 2018 were immaterial.

The measurement period under SAB 118 ended in December 2018. However, Tax Reform uncertainties still remain and I&M will continue to monitor income tax effects that may change as a result of future legislation and further interpretation of Tax Reform based on proposed U.S. Treasury regulations and guidance from the IRS and state tax authorities.

Federal Legislation

The IRS has proposed new regulations that provide guidance regarding the additional first-year depreciation deduction under Section 168(k). The proposed regulations reflect changes as a result of Tax Reform and affect taxpayers with qualified depreciable property acquired and placed in service after September 27, 2017. Generally, I&M’s regulated businesses will not be eligible for any bonus depreciation for property acquired and placed in service after January 1, 2018. However, for self-constructed property and other property placed in service in 2018 for which construction began prior to January 1, 2018, taxpayers are required to evaluate the contractual terms to determine if these additions qualify for 100% expensing under Tax Reform or 50% bonus depreciation as provided under prior tax law.

Excess and Deficient Accumulated Deferred Income Taxes as Result of Tax Reform

Accounting guidance for “Income Taxes” requires deferred tax assets and liabilities to be measured at the enacted income tax rate expected to apply when the related temporary differences will be realized or settled. As a result, I&M’s deferred tax assets and liabilities were re-measured in December 2017 using the newly enacted tax rate of 21% resulting in excess or deficient accumulated deferred income taxes (ADIT).

With respect to I&M’s regulated operations, the change to net deferred income taxes was primarily offset by a corresponding change in net income tax related regulatory assets and liabilities to reflect amounts expected to be provided to customers. Where the deferred income tax amount was not previously contemplated in regulated rates or pertained to unregulated operations, the re-measurement was recorded as an adjustment to income tax expense.

The FERC accounts affected by the re-measurement of ADIT include:

182.3 Other Regulatory Assets
190 Accumulated Deferred Income Taxes

254 Other Regulatory Liabilities
281 Accumulated Deferred Income Taxes – Accelerated Amortization
282 Accumulated Deferred Income Taxes – Other Property
283 Accumulated Deferred Income Taxes – Other
410.1 Provision for Deferred Income Taxes, Utility Operating Income
410.2 Provision for Deferred Income Taxes, Utility Non-Operating Income
411.1 Provision for Deferred Income Taxes – Credit, Utility Operating Income
411.2 Provision for Deferred Income Taxes – Credit, Utility Non-Operating Income

Tax Reform included certain rate normalization requirements that stipulate how the portion of total excess or deficient ADIT related to certain depreciable property must be returned to customers. Specifically, regulated public utilities subject to these rate normalization requirements must recognize the impact of re-measured deferred taxes applicable to prior depreciation using ARAM. As a result, once the amortization of Excess ADIT is reflected in rates, customers will receive the benefits over the remaining weighted-average useful life of the applicable property. The remaining balance of excess or deficient ADIT will be returned to customers via the mechanisms and time periods as agreed to and/or ordered by the IURC and MPSC. See Note 4 – Rate Matters for additional information.

As of December 31, 2018, I&M had $575 million of Excess ADIT as well as an incremental liability of $142 million to reflect the Excess ADIT on a pretax basis which is presented in Other Regulatory Liabilities on the balance sheets. $361 million of the Excess ADIT relates to temporary differences associated with depreciable property.

During 2018, I&M recognized $26 million of amortization of Excess ADIT within Provision for Deferred Income Taxes – Credit, Utility Operating Income on the statements of income.

Income Tax Expense

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

	Years Ended December 31, 2018	2017
	(in millions)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ 81.6	$ (116.6)
Deferred	(44.9)	196.9
Deferred Investment Tax Credits	(4.7)	(4.7)
Total	32.0	75.6
Charged (Credited) to Nonoperating Income, Net:		
Current	(5.0)	1.9
Deferred	2.1	4.1
Total	(2.9)	6.0
Total Income Taxes	$ 29.1	$ 81.6

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, 2018	2017
	(in millions)	
Net Income	$ 261.3	$ 186.8

Income Tax Expense	29.1	81.6
Pretax Income	$ 290.4	$ 268.4
Income Taxes on Pretax Income at Statutory Rate (21% and 35% in 2018 and 2017, Respectively)	$ 61.0	$ 93.9
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
Depreciation	(0.7)	11.4
Investment Tax Credits Amortization	(4.7)	(4.7)
State and Local Income Taxes, Net	13.4	(6.2)
Removal Costs	(8.0)	(13.2)
AFUDC	(2.5)	(5.6)
Tax Adjustments	—	2.4
Tax Reform Adjustments	—	2.3
Tax Reform Excess ADIT Reversal	(25.8)	—
Other	(3.6)	1.3
Income Tax Expense	$ 29.1	$ 81.6
Effective Income Tax Rate	10.0%	30.4%

Net Deferred Tax Liability

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

	December 31,	
	2018	**2017**
	(in millions)	
Deferred Tax Assets	$ 771.9	$ 1,096.8
Deferred Tax Liabilities	(1,721.9)	(2,050.4)
Net Deferred Tax Liabilities	$ (950.0)	$ (953.6)
Property Related Temporary Differences	$ (446.9)	$ (403.0)
Amounts Due to Customers for Future Federal Income Taxes	142.0	137.6
Deferred State Income Taxes (a)	(139.7)	(180.5)
Deferred Income Taxes on Other Comprehensive Loss	3.7	(3.9)
Accrued Nuclear Decommissioning	(453.7)	(457.0)
Regulatory Assets	(31.9)	(43.8)
Net Operating Loss Carryforward	0.2	1.6
All Other, Net	(23.7)	(4.6)
Net Deferred Tax Liabilities	$ (950.0)	$ (953.6)

(a) In 2018, I&M recorded a $40 million correction related to the accounting for the impact of Tax Reform in 2017. The correction resulted in a decrease of Other Regulatory Assets and Accumulated Deferred Income Taxes – Other of $4 million and $44 million, respectively, with an offsetting increase to Other Regulatory Liabilities of $40 million as of December 31, 2018. Management concluded the misstatement was not material to the 2017 financial statements or the financial statements of any of the interim periods in 2018.

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 and tax credits, 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 through 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, I&M and other AEP subsidiaries and the IRS exam team agreed to utilize the Fast Track Settlement Program in December 2017. The program was completed in March 2018 and tax years 2014 and 2015 were added to the IRS examination to reflect the impact of the Fast Track changes that were carried forward to 2014 and 2015. In June 2018, I&M and other AEP subsidiaries settled all outstanding issues under audit for tax years 2011-2015. The Joint Committee approved the settlement in November 2018. The settlement did not materially impact I&M's net income, cash flows or financial condition. The IRS examination of 2016 began in October 2018.

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 2007.

Uncertain Tax Positions

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

	2018	2017
	(in millions)	
Balance as of January 1,	$ 3.2	$ 3.8
Increase – Tax Positions Taken During a Prior Period	—	0.2
Decrease – Tax Positions Taken During a Prior Period	—	(0.5)
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	$ 3.2

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $2.6

million and $2.1 million for 2018 and 2017, respectively. Management believes that there will be no significant net increase or decrease in unrecognized benefits within 12 months of the reporting date.

State Tax Legislation

In June 2018, the United States Supreme Court issued a decision which eliminated a physical presence requirement for the imposition of sales and use tax and instead applied an economic nexus concept. Although this case was specific to sales and use taxes, many states are beginning to consider whether they could also apply this economic nexus concept to income taxes. Management continues to monitor state legislation to determine whether it could create any income tax liability in any states in which I&M currently does not file.

12. LEASES

Leases of property, plant and equipment are for remaining periods up to 13 years and require payments of related property taxes, maintenance and operating costs. Many of the leases have purchase or renewal options. Leases not renewed are often 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 were as follows:

	Years Ended December 31, 2018	Years Ended December 31, 2017
	(in millions)	
Net Lease Expense on Operating Leases	$ 89.2	$ 88.4
Amortization of Capital Leases	119.6	131.7
Interest on Capital Leases	8.2	7.0
Total Lease Rental Costs	$ 217.0	$ 227.1

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

	December 31, 2018	December 31, 2017
	(in millions)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 27.0	$ 27.2
Other Property, Plant and Equipment	155.6	213.8
Total Property, Plant and Equipment	182.6	241.0
Accumulated Amortization	21.7	21.1
Net Property, Plant and Equipment Under Capital Leases	$ 160.9	$ 219.9
Obligations Under Capital Leases:		
Noncurrent	$ 91.8	$ 120.6
Current	69.1	99.3
Total Obligations Under Capital Leases	$ 160.9	$ 219.9

Future minimum lease payments consisted of the following as of December 31, 2018:

	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2019	$ 88.1	$ 92.6
2020	51.1	89.3
2021	21.3	84.8
2022	10.9	83.8
2023	5.7	6.5
Later Years	21.6	19.5
Total Future Minimum Lease Payments	198.7	$ 376.5
Less Estimated Interest Element	37.8	
Estimated Present Value of Future Minimum Lease Payments	$ 160.9	

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 the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, I&M is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the amount guaranteed. As of December 31, 2018, the maximum potential loss by I&M for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term was $4 million.

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, 2018 were as follows:

	Future Minimum Lease Payments
	(in millions)
2019	$ 73.9
2020	73.9
2021	73.9
2022	73.6
Total Future Minimum Lease Payments	$ 295.3

Railcar Lease

In 2003, AEP Transportation LLC, a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. In 2008, AEP Transportation LLC assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignments are accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M exercised all renewal options for the maximum lease term. The future minimum lease obligations were $6 million for the remaining railcars as of December 31, 2018. These obligations are included in the future minimum lease payments schedule earlier in this note.

Under the remaining five-year 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 is equal to 77% of the projected fair value of the equipment. I&M assumed the guarantee under the return-and-sale option. The maximum potential losses related to the guarantee were $5 million as of December 31, 2018, 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 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 May 2018, I&M entered into a sale-and-leaseback transaction for $56 million with DCC Fuel XII LLC (DCC XII). DCC XII 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 June 2018.

13. FINANCING ACTIVITIES

Long-term Debt

The following table details long-term debt outstanding:

	Maturity	Weighted-Average Interest Rate as of December 31, 2018	Interest Rate Ranges as of December 31, 2018	Interest Rate Ranges as of December 31, 2017	Outstanding as of December 31, 2018	Outstanding as of December 31, 2017
					(in millions)	
Senior Unsecured Notes	2019-2048	4.38%	3.20%-6.05%	3.20%-7.00%	$ 2,175.0	$ 1,825.0
Pollution Control Bonds (a)	2018-2025 (b)	2.49%	1.81%-3.05%	1.75%-2.75%	267.0	267.0
Spent Nuclear Fuel Obligation (c)					273.6	268.6

Other Long-term Debt	2018-2025	3.80%	3.66%-6.00%	2.82%-6.00%	212.8	214.4
Unamortized Discount, Net					(8.7)	(5.6)
Total Long-term Debt					$ 2,919.7	$ 2,569.4

(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 SNF. See "Spent Nuclear Fuel Disposal" section of Note 6 for additional information.

As of December 31, 2018, long-term debt was payable as follows:

	(in millions)
2019	$ 78.5
2020	1.8
2021	242.1
2022	2.2
2023	252.3
After 2023	2,351.5
Principal Amount	2,928.4
Unamortized Discount, Net	(8.7)
Total Long-term Debt	$ 2,919.7

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. However, the Federal Power Act creates a reserve on retained earnings attributable to hydroelectric generation plants. Because of their ownership of such plants, this reserve applies to I&M.

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

The most restrictive dividend limitation for I&M is through the credit agreements. As of December 31, 2018, 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 $1.5 billion.

The Federal Power Act restriction limits the ability of I&M to pay dividends out of retained earnings because of their ownership in hydroelectric generation. Additionally, the credit agreement covenant restrictions can limit the ability of I&M to pay dividends out of retained earnings. As of December 31, 2018, the amount of any such restrictions was $454 million.

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, 2018 and 2017 are included in Notes Payable to Associated Companies on the 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)					
2018	$ 322.1	$ 645.1	$ 255.5	$ 147.4	$ 1.1	$ 500.0
2017	367.4	—	204.9	—	211.6	500.0

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

Years Ended December 31,	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2018	2.97%	1.83%	2.97%	1.81%	2.16%	2.07%
2017	1.85%	0.92%	—%	—%	1.27%	—%

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, 2018 and 2017.

Securitized Accounts Receivables – AEP Credit

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

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and includes a $125 million and a $625 million facility, which expire in July 2020 and 2021, respectively.

The amount of accounts receivable and accrued utility revenues under the sale of receivables agreement as of December 31, 2018 and 2017 were $153 million and $137 million, respectively.

The fees paid to AEP Credit for customer accounts receivable sold were $9 million and $7 million for the years ended December 31, 2018 and 2017, respectively.

The proceeds on the sale of receivables to AEP Credit were $1.8 billion and $1.6 billion for the years ended December 31, 2018 and 2017, respectively.

14. <u>RELATED PARTY TRANSACTIONS</u>

For other related party transactions, also see “AEP System Tax Allocation Agreement” section of Note 11 in addition to “Corporate Borrowing Program – AEP System” and “Securitized Accounts Receivables – AEP Credit” sections of Note 13.

Power Coordination Agreement and Bridge Agreement

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

- Under the FERC approved PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.
- A Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement that, amongst other things, addresses the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement.

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. Certain power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies’ respective equity positions.

System Integration Agreement

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 generally accrue to the benefit of APCo, I&M, KPCo and WPCo. 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 for the years ended December 31, 2018 and 2017:

Related Party Revenues	Years Ended December 31, 2018	2017
	(in millions)	
Direct Sales to East Affiliates	$ 0.1	$ —
Direct Sales to West Affiliates	—	3.8
Auction Sales to OPCo (a)	7.1	—
Transmission Agreement Sales	11.7	(4.4)
Other Revenues	3.2	2.4

(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 for the years ended December 31, 2018 and 2017:

Related Party Purchases	Years Ended December 31, 2018	2017
	(in millions)	
Direct Purchases from AEGCo	$ 237.9	$ 223.9

Transmission Agreement

APCo, I&M, KGPCo, KPCo, OPCo and WPCo (AEP East Companies) are parties to the TA, 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, 2018 and 2017 related to the TA were $91 million and $104 million, respectively, recorded in Operation Expenses on the statements of income.

Joint License Agreement

AEP Transmission Company (AEPTCo) entered into a 50-year joint license agreement with I&M allowing either party to occupy the granting party's facilities or real property. After the expiration of the agreement, the term shall automatically renew for successive one-year terms unless either party provides notice. The joint license billing provides compensation to the granting party for the cost of carrying assets, including depreciation expense, property taxes, interest expense, return on equity and income taxes. For the years ended December 31, 2018 and 2017, AEPTCo billed I&M $2 million and $1 million, respectively.

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. Certain affiliated entities, including I&M, 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 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 ROE 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 AEGCo and KPCo, 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 of $12 million and $10 million in 2018 and 2017, respectively, for the transloading services in Fuel Stock on the balance sheets.

Cook Coal Terminal also performs railcar maintenance services at cost for I&M. AEGCo billed I&M $2 million and $1 million for the years ended December 31, 2018 and 2017, 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 $63 million for the years ended December 31, 2018 and 2017, 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. I&M recorded billings from APCo of $2 million and $3 million as capital or maintenance expenses depending on the nature of the services received for the years ended December 31, 2018 and 2017, respectively. These billings are recoverable from customers.

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 in Utility Plant on the balance sheets at net book value:

	Years Ended December 31, 2018	2017
	(in millions)	
Sales	$ 8.2	$ 5.0
Purchases	2.0	3.5

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 I&M. The costs of the services are based on a direct charge or on a prorated basis and billed to I&M at AEPSC's cost. AEPSC and its billings are subject to regulation by the FERC. I&M's total billings from AEPSC were $174 million and $176 million for the years ended December 31, 2018 and 2017, respectively.

15. PROPERTY, PLANT AND EQUIPMENT

Depreciation

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

Year	Nuclear	Steam	Other Generation	Hydro	Transmission	Distribution	General
				(in percentages)			
2018	2.4	6.6	7.0	2.4	1.8	3.1	8.9

2017	1.9	3.8	5.3	2.7	1.7	2.7	8.4

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

Asset Retirement Obligations

I&M records ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for legal obligations for asbestos removal, the retirement of certain ash disposal facilities and the decommissioning of the Cook Plant. 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 its 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, 2018 and 2017, I&M's ARO liability for nuclear decommissioning of the Cook Plant was $1.66 billion and $1.30 billion, respectively. These liabilities are reflected in Asset Retirement Obligations on I&M's balance sheets. As of December 31, 2018 and 2017, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $2.16 billion and $2.22 billion, respectively. These assets are included in Other Special Funds on I&M's balance sheets. The following is a reconciliation of the 2018 and 2017 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)		
2018	$ 1,321.8	$ 58.7	$ (0.2)	$ 301.0 (a)	$ 1,681.3
2017	1,258.1	55.9	(0.1)	7.9	1,321.8

(a) Revision for Cook Plant related to a new third-party study, which impacted the ARO liability for changes of estimated cash flows and application of the new discount rate.

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:

			I&M's Share as of December 31, 2018		
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%	$ 1,108.7	$ 50.2	$ 514.1

			I&M's 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

(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 nonaffiliated company. See the "Rockport Lease" section of Note 12.

(c) AEGCo owns 50% of Unit 1 with I&M and 50% of capital additions for Unit 2.

16. REVENUE FROM CONTRACTS WITH CUSTOMERS

Disaggregated Revenues from Contracts with Customers

The following table represents I&M's revenues from contracts with customers, net of respective provisions for refund, by type of revenue:

		Twelve Months Ended December 31, 2018 (in millions)
Retail Revenues:		
Residential Revenues	$	716.0
Commercial Revenues		479.0
Industrial Revenues		545.9
Other Retail Revenues		7.2
Total Retail Revenues		1,748.1
Wholesale Revenues:		
Generation Revenues (a)		497.3
Transmission Revenues (a)		23.1
Total Wholesale Revenues		520.4
Other Revenues from Contracts with Customers (a)		26.0
Total Revenues from Contracts with Customers		2,294.5
Other Revenues:		
Alternative Revenues (a)		(2.1)
Other Revenues		(8.3)
Total Other Revenues		(10.4)
Total Operating Revenues	$	2,284.1

(a) Amounts include affiliated and nonaffiliated revenues.

Performance Obligations

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

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

Retail Revenues

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

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

Wholesale Revenues – Generation

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

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

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

Wholesale Revenues - Transmission

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

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

APCo, I&M, KGPCo, KPCo, OPCo and WPCo (AEP East Companies) are parties to the TA, which defines how transmission costs are allocated among the AEP East Companies on a 12-month average coincident peak basis. Affiliate revenues as a result of the TA are reflected as Transmission Revenues in the disaggregated revenues table above.

Fixed Performance Obligations

The following table represents the remaining fixed performance obligations satisfied over time as of December 31, 2018. Fixed performance obligations primarily include wholesale transmission services, electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. The amounts below include affiliated and nonaffiliated revenues.

2019	2020-2021	2022-2023	After 2023	Total
		(in millions)		
$ 25.6	$ 2.9	$ 2.9	$ —	$ 31.4

Contract Assets and Liabilities

Contract assets are recognized when I&M has a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. I&M did not have any material contract assets as of December 31, 2018.

When I&M receives consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheets in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. Contract liabilities typically arise from services provided under joint use agreements for utility poles. I&M did not have any material contract liabilities as of December 31, 2018.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on I&M's balance sheets within the Customer Accounts Receivable line item. I&M's balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Customer Accounts Receivable were not material as of December 31, 2018. See "Securitized Accounts Receivable - AEP Credit" section of Note 13 for additional information.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable from Associated Companies on I&M's balance sheets were $35 million and 15 million, respectively, as of December 31, 2018 and January 1, 2018.

Contract Costs

Contract costs to obtain or fulfill a contract are accounted for under the guidance for "Other Assets and Deferred Costs" and presented as a single asset and are neither bifurcated nor reclassified between current assets and deferred debits on the balance sheets. Contract costs to acquire a contract are amortized in a manner consistent with the transfer of goods or services to the customer in Operation Expenses on the statements of income. I&M did not have material contract costs as of December 31, 2018.

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, 2018 and 2017, 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, 2018								
East Busco Station	Distribution	Churubusco, IN	363	$ 5.6	562	$ -	592	$ -
Year Ended December 31, 2017								
East Busco Station	Distribution	Churubusco, IN	363	$ 5.6	562	$ -	592	$ -

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

Name of Respondent	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 2018/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				(4,256,738)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				68,917
3	Preceding Quarter/Year to Date Changes in Fair Value				2,745,882
4	Total (lines 2 and 3)				2,814,799
5	Balance of Account 219 at End of Preceding Quarter/Year				(1,441,939)
6	Balance of Account 219 at Beginning of Current Year				(1,441,939)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(413,482)
8	Current Quarter/Year to Date Changes in Fair Value				(525,083)
9	Total (lines 7 and 8)				(938,565)
10	Balance of Account 219 at End of Current Quarter/Year				(2,380,504)

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 2018/Q4

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	(11,999,775)		(16,256,513)	[redacted]	[redacted]
2	1,318,349		1,387,266	[redacted]	[redacted]
3			2,745,882	[redacted]	[redacted]
4	1,318,349		4,133,148	186,742,763	190,875,911
5	(10,681,426)		(12,123,365)	[redacted]	[redacted]
6	(10,681,426)		(12,123,365)	[redacted]	[redacted]
7	1,602,332		1,188,850	[redacted]	[redacted]
8	(2,300,608)		(2,825,691)	[redacted]	[redacted]
9	(698,276)		(1,636,841)	261,301,657	259,664,816
10	(11,379,702)		(13,760,206)	[redacted]	[redacted]

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)	8,391,591,582	8,391,591,582
4	Property Under Capital Leases	38,632,524	38,632,524
5	Plant Purchased or Sold		
6	Completed Construction not Classified	647,617,810	647,617,810
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	9,077,841,916	9,077,841,916
9	Leased to Others		
10	Held for Future Use	1,444,928	1,444,928
11	Construction Work in Progress	465,252,782	465,252,782
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	9,544,539,626	9,544,539,626
14	Accum Prov for Depr, Amort, & Depl	3,068,176,859	3,068,176,859
15	Net Utility Plant (13 less 14)	6,476,362,767	6,476,362,767
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,921,423,240	2,921,423,240
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	146,748,989	146,748,989
22	Total In Service (18 thru 21)	3,068,172,229	3,068,172,229
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	4,630	4,630
29	Amortization		
30	Total Held for Future Use (28 & 29)	4,630	4,630
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	3,068,176,859	3,068,176,859

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 2018/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
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					32
					33

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 2018/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	33,394,990	49,393,175
4	Allowance for Funds Used during Construction	4,052,369	1,670,875
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	37,447,359	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)	1,347,289	166,507,028
10	SUBTOTAL (Total 8 & 9)	1,347,289	
11	Spent Nuclear Fuel (120.4)	695,441,601	110,752,119
12	Nuclear Fuel Under Capital Leases (120.6)	180,028,830	55,500,000
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	695,661,521	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	218,603,558	
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
	54,891,918	27,896,247	3
	1,351,232	4,372,012	4
			5
		32,268,259	6
			7
			8
	166,252,119	1,602,198	9
		1,602,198	10
	287,428,305	518,765,415	11
113,247,464		122,281,366	12
-110,762,973	287,428,305	518,996,189	13
		155,921,049	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 - $110,752,119

Reclassification of nuclear fuel from owned to leased due to sale/leaseback with third party - $55,500,000

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

Retirement of spent fuel

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

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

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

Reclassification of $55,500,000 of nuclear fuel from owned to leased due to sale/leaseback with third party

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

Includes 2018 costs in connection with nuclear leases:
Finance charges - $4,913,216

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

Retirement of nuclear fuel

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2018

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106)

1. Report below the original cost of plant in service in the same detail as in the current depreciation order.
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. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such amounts.
5. 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 distrubtions 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) reversals of tentative distributions of prior year of unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	301 Organization	117,426	0
3	302 Franchises and Consents	19,866,098	0
4	303 Miscellaneous Intangible Plant	146,811,085	42,692,624
5	TOTAL Intangible Plant	**166,794,609**	**42,692,624**
6	2. PRODUCTION PLANT		
7	Steam Production Plant		
8	310.1 Land	7,194,782	0
9	310.2 Land Rights	219,723	0
10	311 Structures and Improvements	107,353,830	477,766
11	312 Boiler Plant Equipment	769,082,191	3,012,987
12	313 Engines and Engine-Driven Generators	0	0
13	314 Turbogenerator Units	111,102,700	11,718,805
14	315 Accessory Electric Equipment	62,768,045	346,962
15	316 Miscellaneous Power Plant Equipment	23,356,149	455,598
16	317 Asset Retirement Costs for Steam Production	13,571,817	1,070,249
17	TOTAL Steam Production Plant	**1,094,649,237**	**17,082,367**
18	Nuclear Production Plant		
19	320.1 Land	1,879,588	0
20	320.2 Land Rights	0	0
21	321 Structures and Improvements	426,490,247	3,418,572
22	322 Reactor Plant Equipment	1,505,616,070	116,993,482
23	323 Turbogenerator Units	652,465,579	30,743,265
24	324 Accessory Electric Equipment	257,347,480	12,231,841

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2018

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

reversals of the prior year's 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.

6. Show in column (f) reclassification 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. In showing the clearance of 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.

7. 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 requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, 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 of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
0	0	0	117,426	301	2
0	0	0	19,866,098	302	3
11,371,460	0	0	178,132,249	303	4
11,371,460	**0**	**0**	**198,115,773**		5
					6
					7
0	0	0	7,194,782	310.1	8
0	0	0	219,723	310.2	9
63,187	0	0	107,768,409	311	10
1,119,276	0	49,642	771,025,544	312	11
0	0	0	0	313	12
1,080,074	0	0	121,741,431	314	13
18,605	0	0	63,096,402	315	14
53,331	0	(49,642)	23,708,774	316	15
0	0	0	14,642,066	317	16
2,334,473	**0**	**0**	**1,109,397,131**		17
					18
0	0	0	1,879,588	320.1	19
0	0	0	0	320.2	20
1,397,943	0	0	428,510,876	321	21
38,550,247	0	0	1,584,059,305	322	22
5,958,625	0	0	677,250,219	323	23
2,047,493	0	0	267,531,828	324	24

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2018

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Addition (c)
25	325 Miscellaneous Power Plant Equipment	254,970,135	5,737,644
26	326 Asset Retirement Costs for Nuclear Production	135,680,600	309,233,142
27	TOTAL Nuclear Production Plant	**3,234,449,699**	**478,357,946**
28	Hydraulic Production Plant		
29	330.1 Land	510,116	0
30	330.2 Land Rights	196,186	0
31	331 Structures and Improvements	3,798,252	743,921
32	332 Reservoirs, Dams and Waterways	22,223,358	3,364,075
33	333 Water Wheels, Turbines and Generators	16,406,861	19,647
34	334 Accessory Electric Equipment	5,411,478	231,706
35	335 Miscellaneous Power Plant Equipment	2,641,655	141,045
36	336 Roads, Railroads and Bridges	853	0
37	337 Asset Retirement Costs for Hydraulic Production	318,520	0
38	TOTAL Hydraulic Production Plant	**51,507,279**	**4,500,394**
39	Other Production Plant		
40	340.1 Land	181,743	0
41	340.2 Land Rights	0	0
42	341 Structures and Improvements	735,119	0
43	342 Fuel Holders, Products and Accessories	0	0
44	343 Prime Movers	0	0
45	344 Generators	35,380,624	0
46	345 Accessory Electric Equipment	269,062	0
47	346 Miscellaneous Power Plant Equipment	556,726	7,882
48	347 Asset Retirement Costs for Other Production	0	0
49	TOTAL Other Production Plant	**37,123,274**	**7,882**
50	TOTAL Production Plant	**4,417,729,489**	**499,948,589**
51	3. TRANSMISSION PLANT		
52	350.1 Land	10,483,742	1,565,634
53	350.2 Land Rights	59,926,523	1,226,638
54	352 Structures and Improvements	26,942,629	4,922,404
55	353 Station Equipment	722,070,208	74,888,463
56	354 Towers and Fixtures	233,280,173	85,626
57	355 Poles and Fixtures	176,476,749	20,149,314
58	356 Overhead Conductors and Devices	265,629,035	3,728,479
59	357 Underground Conduit	2,312,344	0
60	358 Underground Conductors and Devices	6,201,043	206,468

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2018

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1,615,632	0	(331,012)	258,761,135	325	25
5,884,094	0	0	439,029,648	326	26
55,454,034	**0**	**(331,012)**	**3,657,022,599**		27
					28
0	0	0	510,116	330.1	29
0	0	0	196,186	330.2	30
619	0	0	4,541,554	331	31
163,939	0	0	25,423,494	332	32
51,795	0	0	16,374,713	333	33
109,693	0	0	5,533,491	334	34
18,149	0	0	2,764,551	335	35
0	0	0	853	336	36
0	0	0	318,520	337	37
344,195	**0**	**0**	**55,663,478**		38
					39
0	0	0	181,743	340.1	40
0	0	0	0	340.2	41
0	0	0	735,119	341	42
0	0	0	0	342	43
0	0	0	0	343	44
0	0	0	35,380,624	344	45
0	0	0	269,062	345	46
0	0	0	564,608	346	47
0	0	0	0	347	48
0	**0**	**0**	**37,131,156**		49
58,132,702	**0**	**(331,012)**	**4,859,214,364**		50
					51
821	0	0	12,048,555	350.1	52
0	0	0	61,153,161	350.2	53
590,978	0	256,134	31,530,189	352	54
25,419,567	0	(243)	771,538,861	353	55
400,159	0	10	232,965,650	354	56
6,614,354	0	158,289	190,169,998	355	57
828,306	0	(158,299)	268,370,909	356	58
0	0	0	2,312,344	357	59
18,820	0	0	6,388,691	358	60

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2018

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

Line No.	Account (a)		Balance at Beginning of Year (b)	Additions (c)
61	359	Roads and Trails	347,293	0
62	359.1	Asset Retirement Costs for Transmission Plant	0	0
63	TOTAL	Transmission Plant	**1,503,669,739**	**106,773,026**
64		4. DISTRIBUTION PLANT		
65	360.1	Land	7,422,921	1,682,009
66	360.2	Land Rights	14,182,017	622,475
67	361	Structures and Improvements	24,635,228	5,671,302
68	362	Station Equipment	305,949,116	80,345,286
69	363	Storage Battery Equipment	5,608,271	106,915
70	364	Poles, Towers and Fixtures	272,682,813	18,644,490
71	365	Overhead Conductors and Devices	445,041,747	27,530,859
72	366	Underground Conduit	103,457,524	22,513,055
73	367	Underground Conductors and Devices	247,893,982	17,033,570
74	368	Line Transformers	318,976,192	23,367,144
75	368.1	Capacitors	0	0
76	369	Services	178,509,072	8,231,172
77	370	Meters	96,632,666	3,027,043
78	371	Installations on Customers' Premises	27,065,728	929,949
79	372	Leased Property on Customers' Premises	0	0
80	373	Street Lighting and Signal Systems	21,006,579	1,024,892
81	374	Asset Retirement Costs for Distribution Plant	0	0
82	TOTAL	Distribution Plant	**2,069,063,856**	**210,730,161**
83		5. GENERAL PLANT		
84	389.1	Land	3,010,125	43,134
85	389.2	Lands Rights	178,388	0
86	390	Structures and Improvments	51,730,546	12,732,769
87	391	Office Furniture and Equipment	7,075,561	624,643
88	391.1	Computers / Computer Related Equipment	0	0
89	392	Transportation Equipment	0	0
90	393	Stores Equipment	734,296	181,874
91	394	Tools, Shop and Garage Equipment	14,697,796	1,105,555
92	395	Laboratory Equipment	367,186	0
93	396	Power Operated Equipment	543,715	0
94	397	Communication Equipment	45,656,842	8,709,606
95	398	Miscellaneous Equipment	10,303,235	108,546
96		SUBTOTAL	**134,297,690**	**23,506,127**

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
0	0	(256,134)	91,159	359	61
0	0	0	0	359.1	62
33,873,005	**0**	**(243)**	**1,576,569,517**		63
					64
0	0	(34,196)	9,070,734	360.1	65
0	0	0	14,804,492	360.2	66
295,006	0	(1,323,243)	28,688,281	361	67
5,172,061	0	243	381,122,584	362	68
108,455	0	0	5,606,731	363	69
4,318,640	0	0	287,008,663	364	70
5,947,851	0	24,861	466,649,616	365	71
96,126	0	0	125,874,453	366	72
2,353,921	0	0	262,573,631	367	73
6,695,080	0	(24,861)	335,623,395	368	74
0	0	0	0	368.1	75
1,364,076	0	0	185,376,168	369	76
1,575,566	0	0	98,084,143	370	77
577,149	0	0	27,418,528	371	78
0	0	0	0	372	79
387,184	0	0	21,644,287	373	80
0	0	0	0	374	81
28,891,115	**0**	**(1,357,196)**	**2,249,545,706**		82
					83
0	0	34,196	3,087,455	389.1	84
0	0	0	178,388	389.2	85
1,623,122	0	1,654,255	64,494,448	390	86
1,668,744	0	0	6,031,460	391	87
0	0	0	0	391.1	88
0	0	0	0	392	89
0	0	0	916,170	393	90
223,866	0	0	15,579,485	394	91
126,197	0	0	240,989	395	92
0	0	0	543,715	396	93
291,348	0	0	54,075,100	397	94
34,086	0	0	10,377,695	398	95
3,967,363	**0**	**1,688,451**	**155,524,905**		96

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2018

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
97	399 Other Tangible Property	0	0
98	399.1 Asset Retirement Costs for General Plant	172,921	66,206
99	TOTAL General Plant	**134,470,611**	**23,572,333**
100	TOTAL (Accounts 101 and 106)	**8,291,728,304**	**883,716,733**
101			
102	102 Electric Plant Purchased	0	0
103	(Less) 102 Electric Plant Sold	0	0
104	103 Experimental Plant Unclassified	0	0
105	TOTAL Electric Plant in Service *(Total of lines 94 thru 98)*	**8,291,728,304**	**883,716,733**

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
0	0	0	0	399	97
0	0	0	239,127	399.1	98
3,967,363	**0**	**1,688,451**	**155,764,032**		99
136,235,645	**0**	**0**	**9,039,209,392**		100
					101
0	0	0	0	102	102
0	0	0	0		103
0	0	0	0	103	104
136,235,645	**0**	**0**	**9,039,209,392**		105

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2018

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)
207	54-55	g	The investment and related accumulated depreciation in Generation Step-Up Units (GSUs) in plant accounts 352-353 included in I&M's generation formula rates are identified by a query of the plant accounting system.

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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 2018/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				
39				
40				
41				
42				
43				
44				
45				
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	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

PLANT ACQUISITION ADJUSTMENTS AND ACCUMULATED PROVISION FOR AMORTIZATION OF PLANT ACQUISITION ADJUSTMENTS (Accounts 114 & 115)

1. Report the particulars called for concerning acquisition adjustments.
2. Provide a subheading for each account and list thereunder the information called for, observing the instructions below.
3. Explain each debit and credit during the year, give reference to any Commission orders or other authorizations concerning such amounts, and show contra account debited or credited.
4. For acquisition adjustments arising during the year, state the name of the company from which the property was acquired, date of transaction, and date journal entries clearing Account 102, Plant Purchased or Sold, were filed with the Commission.
5. In the blank space at the bottom of the schedule, explain the plan of disposition of any acquisition adjustments not currently being amortized.
6. Give date Commission authorized use of Account 115.

Line No.	Description (a)	Balance Beginning of Year (b)	Debits (c)	CREDITS Contra Acct. (d)	CREDITS Amount (e)	Balance End of Year (f)
1	Account 114					
2	None					
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15	Account 115					
16	None					
17						
18						
19						
20						

Name of Respondent	This Report Is:	Date of Report	Year of Report
INDIANA MICHIGAN POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2018

CONSTRUCTION WORK IN PROGRESS AND COMPLETED CONSTRUCTION NOT CLASSIFIED - ELECTRIC (Accounts 107 and 106)

1. Report below descriptions and balances at end of year of projects in process of construction and completed construction not classified for projects actually in service. For any substantial amounts of completed construction not classified for plant actually in service explain the circumstances which have prevented final classification of such amounts to prescribed primary accounts for plant in service.
2. The information specified by this schedule for Account 106, Completed Construction Not Classified-Electric, shall be furnished even though this account is included in the schedule, Electric Plant in Service, pages 204-211, according to a tentative classification by primary accounts.
3. Show items relating to "research and development" projects last under a caption Research and Development (See Account 107, Uniform System of Accounts).
4. Minor projects may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Electric (Account 107) (b)	Completed Construction Not Classified-Electric (Account 106) (c)	Estimated Additional Cost of Project (d)
1	South Bend, IN Land Purchase	5,128,852		-
2	IM/IN/Network Assess/Rehab	6,790,716		10,065,960
3	IM/IN NETWORK PRIMARY REHAB FW	2,852,909		-
4	IM/IN NETWORK PRIMARY REHAB EL	4,634,668		439,539
5	IM/IN NETWORK PRIMARY REHAB MU	1,052,814		-
6	Harrison Street Station Opco	1,010,659		3,562,482
7	Cameron Tx addition	3,844,624		-
8	IM/IN/Network Monitor Design	8,126,318		-
9	Langley Tx replacements	2,248,705		-
10	Whitaker Station Rebuild	4,990,346		-
11	IM/IN/D Limberlost Dist	2,673,474		-
12	REP IN 3PH OH Rebuild	1,038,353		14,014,713
13	Maximo Imp - IM - T	1,861,826		-
14	Maximo Imp - IM - G	2,842,453		-
15	Maximo Imp - IM - D	2,727,994		-
16	Maximo Imp - IM - Nuc	4,473,442		-
17	U1 Steam Generator WL Controls	15,271,020		2,908,400
18	Unit 1 Refueling Equipment	1,666,980		2,683,709
19	Unit 2 Refueling Equip Rpl	2,009,987		2,676,143
20	U2 RPS ESFAS	13,281,351		13,678,282
21	U1 RPS ESFAS	14,509,222		12,927,787
22	U1 MSR FW Htr Drains Digital	1,930,966		5,629,813
23	U2 RMS System	13,716,800		3,777,071
24	U1 RMS System	18,354,851		3,736,278
25	U2 Reactor Cavity Lift System	2,659,232		893,140
26	U2 MSR FW Heater Digital Cnt	4,451,585		6,813,025
27	U2 RVI Aging Mgmt Inspections	4,932,293		7,053,296
28	U1 Blowdown Recovery CPI	37,494,378		247,358
29	Unit 1 Spec 200	10,469,109		15,797,652
30	Unit 2 Spec 200	10,140,839		16,418,474
31	U1 Reactor Cntls & Inst Upgrd	9,967,499		385,701
32	U1 Hold Down Spring	1,466,233		1,969,292
33	Unit 2 Hold Down Spring	1,433,651		1,971,002
34	Purchase/Install FCUs	2,128,382		1,650,027
35	**TOTAL**	**465,252,782**	**647,617,809**	**928,564,857**

Name of Respondent INDIANA MICHIGAN POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2018

CONSTRUCTION WORK IN PROGRESS AND COMPLETED CONSTRUCTION NOT CLASSIFIED - ELECTRIC (Accounts 107 and 106)

1. Report below descriptions and balances at end of year of projects in process of construction and completed construction not classified for projects actually in service. For any substantial amounts of completed construction not classified for plant actually in service explain the circumstances which have prevented final classification of such amounts to prescribed primary accounts for plant in service.
2. The information specified by this schedule for Account 106, Completed Construction Not Classified-Electric, shall be furnished even though this account is included in the schedule, Electric Plant in Service, pages 204-211, according to a tentative classification by primary accounts.
3. Show items relating to "research and development" projects last under a caption Research and Development (See Account 107, Uniform System of Accounts).
4. Minor projects may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Electric (Account 107) (b)	Completed Construction Not Classified-Electric (Account 106) (c)	Estimated Additional Cost of Project (d)
1	U1 Main Stator Rewind	10,594,368		32,318,857
2	Fukishima - Flood Hazards Eval	8,274,646		4,002,334
3	Fukushima-Seismic Hazard Eval	8,712,341		19,283,695
4	U1 Baffle-Former Bolt Rplcmnt	18,882,184		29,411,560
5	U1 CRID Fault Coordination	1,730,693		1,420,298
6	U2 CRID Fault Coordination	1,351,622		1,385,070
7	RKP05CIIM Horiz RH ReplaceU1	2,973,272		-
8	RK I&M U2 SCR	42,872,858		106,394,048
9	T/IM/Transmission Line Rebuild	2,722,005		-
10	Transmission Asset Health/IN,M	1,898,881		-
11	T/IM/TranscoAssetRenewl&Refurb	1,136,561		-
12	D/IM/TranscoAssetRenewl&Refurb	4,613,343		-
13	Trans station Renew-Refurb I&M	14,625,831		-
14	Trans Line Renew-RefurbI&M	2,991,442		-
15	Dist Station Renew-Refu I&M IN	5,359,768		-
16	I&M IN Major Eq/Spare -Trans	2,066,167		6,997,887
17	I&M IN Major Eq/Spares- Distr	4,577,256		-
18	T/IM/Capital Blanket - IMPCo	4,353,608		-
19	D/IM/Capital Blanket - IMPCo	2,216,662		-
20	T/IMPC/FWCityImprovements	7,236,527		305,163
21	D/IM/Distribution Work	1,926,530		-
22	I&M Transmission Work	2,221,278		-
23	T/IM/Transmission Work	2,006,003		-
24	D/IM/Distribution Work	3,581,142		782,432
25	IMPCo Distribution Work	4,113,197		-
26	I&M Transmission Work	1,467,183		477,061
27	I&M Transmission Work	8,101,063		5,639,399
28	IMPCo Trans Pre Eng Parent	5,103,646		-
29	IMPCo Trans Pre Eng Parent	2,193,312		-
30	WS-CI-IMPCo-G PPB	4,237,034		-
31	RP-CI-IMPCo-G NMIB	9,224,841		-
32	Ed-Ci-Impco-D Ast Imp	4,678,676		-
33	Ed-Ci-Impco-D Cust Serv	1,954,747		-
34	SS-CI-IMPCo-D GEN PLT	2,149,407		-
35	**TOTAL**	**465,252,782**	**647,617,809**	**928,564,857**

Name of Respondent	This Report Is:	Date of Report	Year of Report
INDIANA MICHIGAN POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2018

CONSTRUCTION WORK IN PROGRESS AND COMPLETED CONSTRUCTION NOT CLASSIFIED - ELECTRIC (Accounts 107 and 106)

1. Report below descriptions and balances at end of year of projects in process of construction and completed construction not classified for projects actually in service. For any substantial amounts of completed construction not classified for plant actually in service explain the circumstances which have prevented final classification of such amounts to prescribed primary accounts for plant in service.
2. The information specified by this schedule for Account 106, Completed Construction Not Classified-Electric, shall be furnished even though this account is included in the schedule, Electric Plant in Service, pages 204-211, according to a tentative classification by primary accounts.
3. Show items relating to "research and development" projects last under a caption Research and Development (See Account 107, Uniform System of Accounts).
4. Minor projects may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Electric (Account 107) (b)	Completed Construction Not Classified-Electric (Account 106) (c)	Estimated Additional Cost of Project (d)
1	Other Minor Projects Which is under 5% or $1,000,000	40,922,157		590,847,909
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14	Completed Construction Not Classified		647,617,809	
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35	**TOTAL**	**465,252,782**	**647,617,809**	**928,564,857**

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Co.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2018

CONSTRUCTION OVERHEADS - ELECTRIC

1. List in columns (a) the kinds of overheads according to the titles used by the respondent. Charges for outside professional services for engineering fees and management or supervision fees capitalized should be shown as separate items.
2. On page 218 furnish information concerning construction overheads.
3. A respondent should not report "none" to this page if no overhead apportionments are made, but rather should explain on page 218 the accounting procedures employed and the amounts of engineering, supervision and administrative costs, etc., which are directly charged to construction.
4. Enter on this page engineering, supervision, administrative, and allowance for funds used during construction, etc., which are first assigned to a blanket work order and then prorated to construction jobs.

Line No.	Description of Overhead (a)	Total Amount Charged for the Year (b)
1	Fossil/Hydro Construction Overheads	5,631,752
2		
3	Nuclear Construction Overheads	16,030,044
4		
5	Transmission Construction Overheads	9,950,664
6		
7	Distribution Construction Overheads	31,157,037
8		
9		
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39	**TOTAL**	**62,769,497**

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Co.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2018

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

1. For each construction overhead explain: (a) the nature and extent of work, etc., the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, (e) basis of differentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned.
2. Show below the computation of allowance for funds used during construction rates, if those differ from the overall rate of return authorized by the Michigan Public Service Commission.

1. The company has certain administrative, supervisory and engineering personnel whose costs cannot, without undue burden and refinement, be classified directly to projects. Construction overheads are used to allocate these indirect costs to individual projects of this kind. The construction overhead rate calculated is applied to applicable capital work order charges.

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 2018/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	2,824,614,321	2,824,609,776	4,545	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	255,843,062	255,842,977	85	
4	(403.1) Depreciation Expense for Asset Retirement Costs	2,017,956	2,017,956		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	461,422	461,422		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	258,322,440	258,322,355	85	
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	120,173,108	120,173,108		
13	Cost of Removal	63,933,838	63,933,838		
14	Salvage (Credit)	7,178,178	7,178,178		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	176,928,768	176,928,768		
16	Other Debit or Cr. Items (Describe, details in footnote):	15,419,877	15,419,877		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,921,427,870	2,921,423,240	4,630	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	313,094,821	313,094,821		
21	Nuclear Production	1,406,634,656	1,406,634,656		
22	Hydraulic Production-Conventional	31,688,196	31,688,196		
23	Hydraulic Production-Pumped Storage				
24	Other Production	4,399,735	4,399,735		
25	Transmission	498,470,086	498,465,456	4,630	
26	Distribution	634,540,221	634,540,221		
27	Regional Transmission and Market Operation				
28	General	32,600,155	32,600,155		
29	TOTAL (Enter Total of lines 20 thru 28)	2,921,427,870	2,921,423,240	4,630	

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

Revised items due to IURC Final Order in I&M's Base Case Cause No. 44967	$	-221,458
Amortize Indiana jurisdiction LCM deferred balances for carrying charges, depreciation, and property tax over a six year period as approved by the IURC in Cause No. 44182 LCM1 and amortize over recovery of all costs from July 2017 - June 2018		-44,246
Amortization per MPSC Order in I&M Base Case No. U-18370		-131,172
Amortize Indiana jurisdiction 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		730,884
Indiana LCM rider to record over/under recovery of depreciation per Cause No. 44182 LCM 1		1,289,215
Amortize Indiana jurisdictional portion of LCM deferred balances per IURC Cause No. 44182 LCM 1		-276,870
DSI over/under for Federal Mandate Rider effective Jan 2015 per IURC Order in Cause No. 44331		-211,366
Michigan deferred depreciation expense for EECO per MPSC Order in Case No. U-17353		10,410
Michigan jurisdictional share of deferred depreciation expense for Cook Plant LCM 1 per Case No. U-17026		377,767
MI Def Clean Energy Solar Pilot Project		-490,618
Amortize net over recovery DSI costs		226,146
In Def Clean Energy Solar Pilot Project per Indiana Order Cause No. 44511		-189,059
SCR over/under for Clean Coal Technology Rider effective July 2016 per IURC Order in Cause 44523		-1,117,371
ARO depreciation expense in account 1080013		515,837
Total		$461,422

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

Includes ($3,052,205) of removal cost in retirement work in progress (RWIP).

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

Includes ($2,756,095) of salvage charges in retirement work in progress (RWIP).

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

Reclassify the gain/loss and deferral of depreciation and accretion expense on retirement and closure of Cook Nuclear Asbestos ARO's	$	5,321,073
Reclassify amounts related to the Innovari Program to Deferred Expense		-16,631
Recorded the original cost, accumulated depreciation plant acquisition adjustment, and clear account 102 for the acquisition of Losantville Station		1,174,281
Transferred the plant acquisition adjustment to accumulated depreciation for the acquisition of Losantville Station		8,945,460
Deferred the incremental depreciation expense for Rockport Unit 2 using 2022 retirement date instead of 2028 for the period April 26, 2018 through December 2022 as approved by the MPSC in Case No. U-18370		1,312,643
ARO Reserve in account 1080013		-1,316,949
Total		$15,419,877

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.

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Name of Respondent	This Report Is:	Date of Report	Year of Report
INDIANA MICHIGAN POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 12/31/18	2018

NONUTILITY PROPERTY (Account 121)

1. Give a brief description and state the location of nonutility property included in Account 121.
2. Designate with a double asterisk any property which is leased to another company. State name of lessee and whether lessee is an associated company.
3. Furnish particulars (details) concerning sales, purchases, or transfers of Nonutility Property during the year.
4. List separately all property previously devoted to public service and give date of transfer to Account 121, Nonutility Property.
5. Minor items (5% of the Balance at the End of the Year for Account 121 or $100,000, whichever is less) may be grouped by (1) previously devoted to public service, or (2) other nonutility property.

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Purchases, Sales Transfers, etc. (c)	Balance at End of Year (d)
1	Water Transportation Facilities, headquartered at St Louis, MO	18,983,292	(870,751)	18,112,541
2	Land near Breed Plant, Fairbanks, IN	4,196,642	(1,354,462)	2,842,180
3	Land, purchased in connection with Jefferson West 765kv Corridor, Jefferson County, IN	164,576		164,576
4	Land, Prosperity East 138kv Corridor, Madison County, IN	102,956		102,956
5	Land and rights near Tanners Creek Plant, Lawrenceburg, IN	4,055,655		4,055,655
6	Land for Fuson Substation, Delaware County, IN	102,430		102,430
7	Minor items previously devoted to public service	8,174		8,174
8	Minor items - other nonutility property	525,324		525,324
	TOTAL	28,139,049	(2,225,213)	25,913,836

ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION OF NONUTILITY PROPERTY (Account 122)

Report below the information called for concerning depreciation and amortization of nonutility property.

Line No.	Item (a)	Amount (b)
1	Balance, Beginning of Year	12,180,000
2	Accruals for Year, Charged to	[redacted]
3	(417) Income from Nonutility Operations	794,660
4	(418) Nonoperating Rental Income	0
5	Other Accounts (Specify):	0
6	Accounts 227 and 243	183,555
7	TOTAL Accruals for Year (Enter Total of lines 3 thru 6)	978,215
8	Net Charges for Plant Retired:	[redacted]
9	Book Cost of Plant Retired	(2,686,149)
10	Cost of Removal	(98,612)
11	Salvage (Credit)	1,453,074
12	TOTAL Net Charges (Enter Total of lines 9 thru 11)	(1,331,687)
13	Non-Utility Retirement Work in Progress	0
14	Other Debit or Credit Items (Describe):	[redacted]
15	Reclassifications from/to Other Accounts	0
16	Balance, End of Year (Enter Total of lines 1, 7, 12, and 14)	11,826,528

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

INVESTMENTS (Accounts 123, 124, 136)

1. Report below the investments in Accounts 123, *Investments in Associated Companies,* 124, *Other* Investment, and 136, *Temporary Cash Investments.*
2. Provide a subheading for each account and list thereunder the information called for:
(a) Investment in securities - List and describe each security owned, giving name of user, date acquired and date of maturity. For bonds, also give principal amount, date of issue, maturity, and interest rate. For capital stock (including capital stock of respondent reacquired under a definite plan for resale pursuant to authorization by the Board of Directors, and included in Account 124, *Other Investments),* state number of shares, class, and series of stock. Minor investments may be grouped by classes. Investments included in Account 136, *Temporary Cash Investments* , also may be grouped by classes.
(b) Investment Advances-Report separately for each person or company the amounts of loans or investment advances which are properly includable in Account 123. Advances subject to current repayment should be included in Accounts 145 and 146. With respect to each advance, show whether the advance is a note or an open account. Each note should be

Line No.	Description of Investment (a)	Book Cost at Beginning of Year *(If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference)* (b) Original	Book Value	Purchases or Additions During Year (c)
1	Account 123 - Investment in Associated Companies	(see pp. 224-225)		
2				
3	Account 124 - Other Investments			
4				
5	Franklin Real Estate and Indiana Franklin - Land Purchase Contracts			
6	-Michigan		554,658	0
7	-Other States		8,475,021	0
8				
9	Fiber Optic Agreements wih AEP Communications,		3,700,485	0
10	Kentucky Data Link, Inc.and Citynet Fiber Network, Inc.			
11				
12	Shell Building Loan		15,000	0
13				
14	Ripley Land Purchase		745,386	0
15				
16	Other Miscellaneous Investments		8,039	0
17				
18	Speculative Allowance		25,488	0
19				
20	Total Account 124		13,524,077	0
21				
22				
23	Account 136 Temporary Cash Investments		0	0
24				
25				
26				
27				
28				
29				
30	Grand Total		13,524,077	0

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

INVESTMENTS (Accounts 123, 124, 136) (Cont'd)

listed giving date of issuance, maturity date, and specifying whether note is a renewal. Designate any advances due from officers, directors, stockholders, or employees. Exclude amounts reported on page 229.
3. For any securities, notes or accounts that were pledged, designate with an asterisk such securities, notes, or accounts and in a footnote state the name of pledgee and purpose of the pledge.
4. 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.
5. Report in column (g) interest and dividend revenues from investments including such revenues from securities disposed of during the year.
6. In column (h) report for each investment disposed of during the year the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including any dividend or interest adjustment includible in column (g).

Sales or Other Dispositions During Year (d)	Principal Amount or No. of Shares at End of Year (e)	Book Cost at End of Year *(If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference)* (f) Original Cost	(f) Book Value	Revenues for Year (g)	Gain on Loss from Investment Disposed of (h)	Line No.
						1
						2
						3
						4
						5
0			554,658			6
81,968			8,393,053			7
						8
324,108			3,376,377			9
						10
						11
0			15,000			12
						13
0			745,386			14
.						15
0			8,039			16
						17
0			25,488			18
						19
406,076			13,118,001			20
						21
						22
						23
						24
						25
						26
						27
						28
						29
406,076	0	0	13,118,001	0	0	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 2018/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			-6,289,416
5	Investment in Subsidiary AOCI			
6	Subtotal			19,034,584
7				
8	Price River Coal Company, Inc.	12-01-65		
9	Common Stock			27,275
10	Subtotal			27,275
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41				
42	Total Cost of Account 123.1 $ 0		TOTAL	19,061,859

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
255,753		-6,033,663		4
				5
255,753		19,290,337		6
				7
				8
		27,275		9
		27,275		10
				11
				12
				13
				14
				15
				16
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255,753		19,317,612		42

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

NOTES AND ACCOUNTS RECEIVABLE SUMMARY FOR BALANCE SHEET

Show separately by footnote the total amount of notes and accounts receivable from directors, officers, and employees included in Notes Receivable (Account 141) and Other Accounts Receivable (Account 143).

Line No.	Accounts (a)	Balance Beginning of Year (b)	Balance End of Year (c)
1	Notes Receivable (Account 141)	0	0
2	Customer Accounts Receivable (Account 142)	56,348,872	74,846,958
3	Other Accounts Receivable (Account 143) (Disclose any capital stock subscriptions received)	1,947,471	1,401,560
4	TOTAL	**58,296,343**	**76,248,518**
5	Less: Accumulated Provision for Uncollectible Accounts-Cr. (Account 144)	206,193	96,625
6	TOTAL, Less Accumulated Provision for Uncollectible Accounts	**58,090,150**	**76,151,893**
7			
8	Account 143 includes employee receivables of $406,791 at		
9	12/31/18 and $458,936 at 12/31/2017 related to a 2001 biweekly		
10	payroll conversion that will be collected when the employees leave		
11	the company.		
12			
13			
14			

ACCUMULATED PROVISION FOR UNCOLLECTIBLE ACCOUNT-CR. (Account 144)

1. Report below the information called for concerning this accumulated provision.
2. Explain any important adjustments of subaccounts.
3. Entries with respect to officers and employees shall not include items for utility services.

Line No.	Item (a)	Utility Customers (b)	Merchandise Jobbing and Contract Work (c)	Officers and Employees (d)	Other (e)	Total (f)
1	Balance beginning of year		206,193			206,193
2	Prov. For uncollectibles for current year		31,093			31,093
3	Account written off (less)		(137,561)			(137,561)
4	Coll. Of accounts written off					
5	Adjustments (explain): Deductions ……………………….		(3,100)			(3,100)
6	Balance end of year		96,625			**96,625**
7						
8						
9						
10						
11						

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

RECEIVABLES FROM ASSOCIATED COMPANIES (Accounts 145, 146)

1. Report particulars of notes and accounts receivable from associated companies* at end of year.
2. Provide separate headings and totals for Accounts 145, Notes Receivable from Associated Companies, and 146, Accounts Receivable from Associated Companies, in addition to a total for the combined accounts.
3. For notes receivable, list each note separately and state purpose for which received. Show also in column (a) date of note, date of maturity and interest rate.
4. If any note was received in satisfaction of an open account, state the period covered by such open account.
5. Include in column (f) interest recorded as income during the year including interest on accounts and notes held at any time during the year.
6. Give particulars of any notes pledged or discounted, also of any collateral held as guarantee of payment of any note or account.

* NOTE: "Associated companies" means companies or persons that, directly or indirectly, through one or more intermediaries, control, or are controlled by, or are under common control with, the account company. This includes related parties.

"Control" (including the terms "controlling," "controlled by," and "under common control with") means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a company, whether such power is exercised through one or more intermediary companies, or alone, or in conjunction with, or pursuant to an agreement, and whether such power is established through a majority or minority ownership or voting of securities, common directors, officers or stockholders, voting trusts, holding trusts, associated companies, contract or any other direct or indirect means.

Line No.	Particulars (a)	Balance Beginning of Year (b)	Totals for Year: Debits (c)	Totals for Year: Credits (d)	Balance End of Year (e)	Interest for Year (f)
1	Account 145					
2	American Electric Power Co	0	2,666,907,688	2,666,907,688	0	1,991,540
3						
4	Account 146					
5	AEP Generating Company	19,499,110	330,753,078	327,405,848	22,846,340	
6	AEP Pro Serv	(58)	73	15	0	
7	AEP Service Corporation	5,890,832	1,273,448,321	1,272,310,068	7,029,085	
8	AEP System Pool (AEPSC)	11,093,956	518,543,758	498,101,477	31,536,237	
9	AEP Texas Central	9,538	593,398	574,755	28,181	
10	AEP Texas North	16,412	170,937	182,031	5,318	
11	AEP Utility Funding LLC	3	18,282	18,285	0	
12	American Electric Power Co	247	309,086,209	309,085,022	1,434	
13	Appalachian Power Co	2,900,048	38,655,497	38,782,760	2,772,785	
14	Blackhawk Coal Company	0	48,778	48,778	0	
15	Cardinal Operating	1,734	12,229	13,963	0	
16	Cook Coal Terminal	22,264	182,594	201,341	3,517	
17	CSW Energy, Inc.	25	8,782	8,166	641	
18	Kentucky Power Co	1,237,150	9,549,206	9,922,815	863,541	
19	Kingsport Power Co	462	150,108	85,218	65,352	
20	Ohio Power Co	1,200,683	34,989,516	35,598,314	591,885	
21	Public Service Co of OK	40,341	1,427,658	1,423,409	44,590	
22	SW Electric Power Co	223,696	2,542,799	2,422,756	343,739	
23	Wheeling Power Co	769	81,356	81,360	765	
24	AEP Energy Services	(54)	164	107	3	
25						

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/18

RECEIVABLES FROM ASSOCIATED COMPANIES (Accounts 145, 146)

Line No.	Particulars (a)	Balance Beginning of Year (b)	Totals for Year: Debits (c)	Totals for Year: Credits (d)	Balance End of Year (e)	Interest for Year (f)
1	AEP Wind Holding Co	(32)	33	1	0	
2	AEP I&M Transmission	2,471,209	30,586,459	31,041,451	2,016,217	
3	AEP Transmission	2,656,421	201,763,851	200,695,688	3,724,584	
4	AEP Credit Inc.	(58)	58	0	0	
5	AEP C&I Company LLC	34	439	473	0	
6	AEP Investments	(58)	62	4	0	
7	AEP T&D Services	0	1,524	1,524	0	
8	AEP Energy, Inc.	0	1,021	918	103	
9	AEP Energy Supply	314	1,548	1,859	3	
10	Dolet Hills Lignite Co, LLC	722	13,268	13,285	705	
11	AEP Onsite Partners	299	6,579	6,496	382	
12	AEP Energy Partners	(6)	518	485	27	
13	United Sciences Testing	(50)	177	119	8	
14	AEP Renewables, LLC	0	3,265	2,971	294	
15	Various Transmission	47,378	17,334,004	17,362,958	18,424	
16						
17						
18						
19						
20						
21						
22						
23						
24						
25	TOTAL	47,313,331	2,769,975,549	2,745,394,720	71,894,160	1,991,540

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 2018/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)	30,732,935	36,307,472	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	621,540	981,098	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	86,985,787	91,874,720	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	68,447,753	68,418,763	Electric
8	Transmission Plant (Estimated)	540,017	2,234,085	Electric
9	Distribution Plant (Estimated)	686,357	1,053,713	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	285,085	268,287	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	156,944,999	163,849,568	Electric
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	2,112,441	2,044,990	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)	190,411,915	203,183,128	

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

Assigned to - Other includes customer account, administrative and general expenses.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2018

PRODUCTION FUEL AND OIL STOCKS (Included in Account 151)

1. Report below the information called for concerning production fuel and oil stock.
2. Show quantities in tons of 2000 lb. Barrels (42 gals.) or Mcf., whichever unit of quantity is applicable.
3. Each kind of coal or oil should be shown separately.
4. If the respondent obtained any of its fuel from its own coal mines or oil or gas lands or leases or from affiliated companies, a statement should be submitted showing the quantity of such fuel so obtained, the quantity used and quantity on hand, and cost of the fuel classified as to the nature of the costs and expenses incurred with appropriate adjustment for the inventories at beginning and end of year.

Line No.	Item (a)	Total Cost (b)	KINDS OF FUEL AND OIL Quantity (Coal Tons) (c)	KINDS OF FUEL AND OIL Cost (Coal) (d)
1	**On hand beginning of year**	30,732,935	778,321	29,490,080
2	**Received during year**	146,910,991	3,511,213	145,596,708
3	**TOTAL**	177,643,926	4,289,534	175,086,788
4	**Used during year (specify department)**			
5	**Electric Generation**	145,530,595	3,464,852	144,361,455
6	Storage Pile Adjustment	(4,194,141)	(78,733)	(4,194,141)
7				
8				
9				
10				
11				
12				
13				
14				
15	**Sold or transferred**			
16	**TOTAL DISPOSED OF**	141,336,454	3,386,119	140,167,314
17	**BALANCE END OF YEAR**	**36,307,472**	903,415	34,919,474

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2018

PRODUCTION FUEL AND OIL STOCKS (Included in Account 151 (Continued)

KINDS OF FUEL AND OIL (Continued)

Quantity (Oil Bbls) (e)	Cost (Oil) (f)	Quantity (g)	Cost (h)	Quantity (i)	Cost (j)	Line No.
16,800	1,242,855					1
14,774	1,314,283					2
31,574	2,557,138					3
						4
14,781	1,169,140					5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
14,781	1,169,140					16
16,793	**1,387,998**					17

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 2018/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)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year	437,081.00	28,481,825	80,899.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	842.00			
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	35,952.00	1,437,114		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27	Consent Decree Surrenders	-1.00	-87	55,440.00	
28	Total	-1.00	-87	55,440.00	
29	Balance-End of Year	401,972.00	27,044,798	25,459.00	
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)		71		
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.

2020		2021		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		2,107,649.00		2,787,427.00	28,481,825	1
								2
								3
				81,376.00		82,218.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						35,952.00	1,437,114	18
								19
								20
								21
								22
								23
								24
								25
								26
						55,439.00	-87	27
						55,439.00	-87	28
80,899.00		80,899.00		2,189,025.00		2,778,254.00	27,044,798	29
								30
								31
								32
								33
								34
								35
357.00		357.00		56,556.00		57,984.00		36
				714.00		714.00		37
								38
				357.00		714.00		39
357.00		357.00		56,913.00		57,984.00		40
								41
								42
								43
					24		95	44
								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 2018/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)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year	34,469.00	169,124		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	549.00		3,785.00	
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	10,454.00	117,452		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Associated Electric Coop,	5,000.00			
23	Alcoa Allowance Mngt	200.00	7,883		
24					
25					
26					
27					
28	Total	5,200.00	7,883		
29	Balance-End of Year	19,364.00	43,789	3,785.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)		41,217		
34	Gains		41,217		
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				

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 2018/Q4

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.

2020		2021		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						34,469.00	169,124	1
								2
								3
3,785.00						8,119.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						10,454.00	117,452	18
								19
								20
								21
						5,000.00		22
						200.00	7,883	23
								24
								25
								26
								27
						5,200.00	7,883	28
3,785.00						26,934.00	43,789	29
								30
								31
								32
							41,217	33
							41,217	34
								35
								36
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								46

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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 of Report 12/31/18

MISCELLANEOUS CURRENT AND ACCRUED ASSETS (Account 174)

1. Give description and amount of other current and accrued assets as of the end of year.
2. Minor items may be grouped by classes, showing number of items in each class.

Line No.	Item (a)	Balance End of Year (b)
1	Department of Energy Spent Nuclear Fuel Canister Reimbursement	31,097,874
2	Non-Highway Fuel Tax Credit for 2016	(10,771)
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
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21		
22		
23		
24		
25	TOTAL	**31,087,103**

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	IMPA - Delivery point study	1,500	186		
3	IMPA - Delivery point study	1,500	186		
4	IMPA - Delivery point study	1,500	186		
5	IMPA - Delivery point study	1,500	186		
6	IMPA - Delivery point study	1,500	186		
7	IMPA - Delivery point study	1,500	186		
8	IMPA - Delivery point study	1,500	186		
9	PJM #AC1-072	458	186	597	186
10	PJM #AD2-054	310	186	159	186
11	PJM #AD2-080	296	186	106	186
12	PJM #AE1-039	427	186	285	186
13	PJM #AE1-089	434	186	152	186
14	PJM #AE1-170	562	186	186	186
15	PJM #AB1-006	620	186	784	186
16	PJM #AB1-087	310	186	311	186
17	PJM #AB1-088	214	186	214	186
18	PJM #AC1-040	217	186	217	186
19	PJM #AC1-059			117	186
20	PJM #AC1-148			139	186
21	**Generation Studies**				
22	South Bend Solar Study	16,000	183	43,991	183
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
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36					
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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 2018/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 #AC1-152			231	186
3	PJM #AC1-172			231	186
4	PJM #AC1-174			41	186
5	PJM #AC1-175			41	186
6	PJM #AC1-225	264	186	269	186
7	PJM #AC2-080	(5,718)	186	501	186
8	PJM #AC2-090	397	186	326	186
9	PJM #AC2-111	1,412	186	1,412	186
10	PJM #AC2-157	391	186	391	186
11	PJM #AC2-176	610	186	610	186
12	PJM #AC2-177	260	186	260	186
13	PJM #AD1-043	511	186	593	186
14	PJM #AD1-064	867	186	867	186
15	PJM #AD1-093	1,131	186	1,131	186
16	PJM #AD1-100	920	186	730	186
17	PJM #AD1-128	678	186	796	186
18	PJM #AD1-137	565	186	565	186
19	PJM #AD1-137	2,249	186	1,551	186
20	PJM #AD2-020	1,347	186	1,219	186
21	**Generation Studies**				
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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 #AD2-071	1,514	186	1,514	186
3	PJM #AD2-079	1,334	186	1,101	186
4	PJM #AD2-087	1,752	186	1,474	186
5	PJM #AD2-132	1,072	186	1,072	186
6	PJM #AD2-138	1,657	186	1,657	186
7	PJM #AE1-207	320	186	106	186
8	PJM #AE1-208	320	186	106	186
9	PJM #AE1-209	214	186	71	186
10	PJM #AE1-210	261	186	87	186
11	PJM #AE1-217	320	186	106	186
12	PJM #V3-007	616	186		
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22					
23					
24					
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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 2018/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	9,722,756		228	3,192,751	6,530,005
2						
3	Cook Plant Refueling Levelization	66,661,493	49,103,527	various	78,289,732	37,475,288
4						
5	Unamortized Loss on Reacquired Debt	1,034,766		428	206,953	827,813
6	Amort 1/1995 - 12/2022					
7						
8	Unrealized Loss on Forward Commitments	2,053,039	27,893,524	various	35,812,328	-5,865,765
9						
10	Netting of Trading Activities Related to Unrealized	5,437,238	7,432,136	various	6,673,119	6,196,255
11	Gains/Losses on Forward Commitments Between					
12	Regulated Assets/Liabilities					
13						
14	Asset Retirement Obligations	248,873		411,403	111,813	137,060
15	Amortz 3/2009 - 3/2020					
16	Per IURC Cause Order #43306					
17						
18	Indiana Rate Case expenses	1,086,689	484,113	928	335,117	1,235,685
19	Per IURC Cause Order #44075					
20						
21	Michigan Rate Case Expenses	540,272	98,203	928	150,330	488,145
22						
23	Deferred RTO Equity Carrying Charges	(97,608)	48,804			-48,804
24	Amort 1/2005 - 12/2019					
25						
26	BridgeCo Transmission Org Funding	290,325		407	139,554	150,771
27	Amort 1/2005 - 12/2019					
28	FERC Docket No. AC04-101-000					
29						
30	Other PJM Integration	270,218		407	129,889	140,329
31	Amort 1/2005 - 12/2019					
32	FERC Docket No. AC04-101-000					
33						
34	Carrying Charges - RTO Startup Costs	186,387		407	89,593	96,794
35	Amort 1/2005 - 12/2019					
36	FERC Docket No. AC04-101-000 and EL05-74-000					
37						
38	Alliance RTO Deferred Expense	166,730		407	80,144	86,586
39	Amort 1/2005 - 12/2019					
40	FERC Docket No. AC04-101-000					
41						
42	SFAS 158 Employer Accounting for Defined	77,801,991	98,921,803	various	91,825,016	84,898,778
43	Benefit Pension & Other Postretirement Plans					
44	TOTAL	604,411,370	805,011,801		861,463,107	547,960,064

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 2018/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	DSM Energy Optimization Program - Michigan	1,520,352	676,737	various	1,375,733	821,356
2	Under-recovered costs					
3						
4	OSS Margin Sharing	8,956,170		447	8,956,170	
5						
6	SFAS 109 Deferred FIT	83,526,170	449,594,363	various	432,094,393	101,026,140
7						
8	SFAS 109 Deferred SIT	180,354,741	17,479,285	various	13,325,128	184,508,898
9						
10	City of Fort Wayne Settlement	6,724,056		588	914,591	5,809,465
11	Amortization 3/13 - 4/25					
12	Per IURC Cause Order #44075					
13						
14	Cook Turbine Replacement - Michigan	5,220,937	717,011	421	1,611,294	4,326,654
15	Per MPSC Case U-16801					
16						
17	Cook Turbine Replacement CC _Indiana	10,643,988	1,634,845	421	834,387	11,444,446
18	Per IURC Cause Order #44075					
19						
20	Cook Unit 2 Baffle Bolts	6,048,714		530	299,936	5,748,778
21	Amort 3/2013 - 2/2038					
22	Per IURC Cause Order #44075					
23						
24	Michigan Renewable Energy Surcharge	8,944	131,974	various	140,918	
25						
26	Cook Life Cycle Management Program - Michigan	14,681,538	3,168,363	various	1,723,214	16,126,687
27	Per MPSC Case U-17026					
28						
29	SFAS 106 Medicare Subsidy	7,140,943		926	1,020,135	6,120,808
30	Amort 1/2013 - 12/2024					
31						
32	Unrecovered Fuel Costs - Michigan	14,897,213	5,069,054	44x	19,966,267	
33						
34	Unrecovered PJM Expenses	48,010,285	10,147,069	555	58,157,354	
35						
36	Rockport DSI Project - Indiana	10,358,749	1,985,052	various	861,289	11,482,512
37	20% Non Federal Mandate Rider Portion					
38	Per IURC Cause Order #44331					
39						
40	Indiana DSM Program	1,222,942	56,764,283	908	56,993,755	993,470
41	Per IURC Cause Order #43287					
42						
43						
44	TOTAL	604,411,370	805,011,801		861,463,107	547,960,064

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 2018/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	Cook Life Cycle Management	232,972	13,194,474	various	13,032,926	394,520
2	Indiana Portion					
3	Per IURC Cause Order #44182					
4						
5	River Transportation Selling Price Variance	2,168,784	10,630,827	417	9,491,450	3,308,161
6						
7	Cook Uprate Project	36,263,041		524	1,271,714	34,991,327
8						
9	Michigan Electric Vehicle Supply Equipment	64,260	24,601	912	11,874	76,987
10	Per MPSC Case U-16496					
11						
12	Clean Energy Solar Pilot Project - Indiana	689,727	402,607	403,440	233,139	859,195
13	Per IURC Cause Order #44511					
14						
15	Under Recovered Environmental Compliance Tracker	273,675	330,159			603,834
16	Per IURC Cause Order No. 43992					
17						
18	Indiana SCR 2 Rider		231,836	431	138,546	93,290
19						
20	PJM Provision for Refund		1,523,911			1,523,911
21						
22	GreenHat Default Contingency		660,007	561	53,341	606,666
23						
24	Deferred Load Management Costs		3,345,997			3,345,997
25						
26	Indiana Off-System Sales and PJM Rider		42,004,023	555	21,918,644	20,085,379
27	Per IURC Cause Order No. 44967					
28						
29	Deferred Depreciation Rockport Unit 2		1,313,213	108	570	1,312,643
30						
31						
32						
33						
34						
35						
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37						
38						
39						
40						
41						
42						
43						
44	TOTAL	604,411,370	805,011,801		861,463,107	547,960,064

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 2018/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	45,371,701	68,285,169	408	66,534,170	47,122,700
2						
3	Property Taxes - Capital Leases	59,967	701,483	408	711,251	50,199
4						
5	Agency Fees, Factored Accts Rec	2,729,847	37,799,656	various	37,471,949	3,057,554
6						
7	River Transport Division	81,255		various	198,646	-117,391
8						
9	Estimated Barging Bills	68,223		various	68,223	
10						
11	Unamortized Credit Line Fees	681,599	753,975	431	459,161	976,413
12	Amortized thru June 2021					
13						
14	Defd Non-taxable Leased Assets	462,452	1,549,907	various	1,801,657	210,702
15						
16	Minor Items	6,208	93,006	various	93,562	5,652
17						
18						
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46						
47	Misc. Work in Progress	193,491				747,624
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	49,654,743				52,053,453

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2018

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.	Account Subdivision (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	Electric			
2	Accrued ARO Expense - SFAS 143	462,620,993	185,081,257	75,537,492
3	Reg Liability - SFAS 143 - ARO	330,759,257	186,803,432	30,027,352
4	Capitalized Cook Costs	4,725,000	6,615,000	1,890,000
5	Capitalized Interest Expense	50,820,464	32,249,032	13,455,703
6	SFAS 158	27,230,697	15,705,359	6,303,405
7	Other (see pp. 234.1A-234.1B)	15,446,641	151,834,685	140,599,262
8	TOTAL (Account 190) (Enter total of lines 2 thru 7)	891,603,052	578,288,765	267,813,214
9	Gas			
10				
11				
12				
13				
14				
15	Other	0		
16	TOTAL Gas (Enter total of lines 10 thru15)	0	0	0
17	Other (Specify)	205,181,550	7,186,894	4,689,635
18	TOTAL (Account 190) *(Enter total of lines 8, 16 & 17)*	1,096,784,602	**585,475,659**	**272,502,849**
19	Classification of Total:			
20	Federal Income Tax	1,097,098,048	584,966,900	272,029,963
21	State Income Tax	(313,446)	508,759	472,886
22	Local Income Tax			

NOTES

In the space provided below, identify by amount and classification, significant items for which deferred taxes are being provided. Indicate insignificant amounts listed under Other.

Line 17 Other - Detail	Balance at Beginning of Year	Balance at End of Year
Non-Utility 190.2 Federal	2,392,732	(68,655)
Non-Utility 190.2 State	(313,446)	(349,319)
SFAS 133	3,450,930	3,024,984
SFAS 87	465,857	632,793
SFAS 109	199,185,477	187,569,827
Total	205,181,550	190,809,630

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2018

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (Continued)

3. If more space is needed, use separate pages as required.
4. In the space provided below, identify by amount and classification, significant items for which deferred taxes are being provided. Indicate insignificant amounts listed other Other.

Changes During Year		ADJUSTMENTS					
		DEBITS		CREDITS			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	Balance at End of Year (k)	Line No.
[redacted]							1
						353,077,228	2
						173,983,177	3
						0	4
						32,027,135	5
						17,828,743	6
						4,211,218	7
0	0		0		0	581,127,501	8
[redacted]							9
							10
							11
							12
							13
							14
						0	15
0	0		0		0	0	16
0	0	Various	363,737,847	Various	375,612,508	190,809,630	17
0	0		363,737,847		375,612,508	771,937,131	18
							19
0	0		363,737,847		375,612,508	772,286,450	20
						(349,319)	21
							22

NOTES *(Continued)*

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2018

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.	Account Subdivision (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				
2	Contributions and Advances for Construction	4,998,165	3,061,645	584,667
3	Provisions for Loss Trading Credit Risk	1,067	4,455	4,504
4	Property Tax Deferrals	2,004,173	3,766,571	3,436,941
5	Federal and State Mitigation Programs	1,099,336	510,509	0
6	Pre 04/83 Nuclear Fuel Cost	14,666,558	45,124,762	38,466,673
7	Nuclear Decommissioning	(440,754)	12,774,654	12,950,955
8	IRS Settlements	(11,657,706)	1,453,333	5,646,379
9	Deferred Gain Sale of Rockport Unit 2	6,216,736	3,338,253	182,869
10	Amortization of Step Up ITC Rockport Unit 2	1,988,366	1,033,896	0
11	Accrued Vacation Pay	5,378,719	3,082,244	685,328
12	Accrued Severance Benefits		0	0
13	Accrued Incentive Plans	8,874,858	8,873,343	7,330,486
14	Book Provision for Uncollectible Debt	72,169	115,124	63,247
15	Mark to Market Gain/Loss	(2,419,560)	7,730,362	10,831,062
16	Capitalized Software Tax	5,670	8,656	7,147
17	Revenue Refunds	7,311,840	11,452,877	8,520,809
18	SFAS 112 Post Employment Benefits	2,293,507	1,441,811	0
19	Accrued Income Tax and Interest	327,876	461,799	268,472
20	Accrued Pension Expense	(31,392,672)	194,023	14,603,466
21	SFAS 106 Post Retirement Benefits	(13,494,689)	2,644,103	6,828,940
22	Accrued SIT	(201,015)	70,026	150,432
23	Restricted Stock	922,976	530,494	539,383
24	NOL-Deferred Tax Asset/AMT Credit Deferred	8,641,982	27,945,536	20,163,554
25	Accrued Environmental Liability		0	0
26	Other Miscellaneous	10,249,039	8,634,087	1,751,827
27	Total Other	15,446,641	144,252,564	133,017,141
28				
29				
30				
31				

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 of Report December 31, 2018

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (Continued)

3. If more space is needed, use separate pages as required.
4. In the space provided below, identify by amount and classification, significant items for which deferred taxes are being provided. Indicate insignificant amounts listed other Other.

Changes During Year		ADJUSTMENTS					
		DEBITS		CREDITS			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
						2,521,187	2
						1,116	3
						1,674,543	4
						588,827	5
						8,008,469	6
						(264,453)	7
						(7,464,660)	8
						3,061,352	9
						954,470	10
						2,981,803	11
						(0)	12
						7,332,002	13
						20,292	14
						681,140	15
						4,161	16
						4,379,772	17
						851,696	18
						134,549	19
						(16,983,229)	20
						(9,309,852)	21
						(120,609)	22
						931,865	23
						860,000	24
						(0)	25
						3,366,779	26
						4,211,218	27
							28
							29
							30
							31

NOTES *(Continued)*

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/18

UNAMORTIZED LOSS AND GAIN ON REACQUIRED DEBT (Account 189, 257)

1. Report under separate subheadings for Unamortized Loss and Unamortized Gain on Reacquired Debt, particulars of gain and loss on reacquisition applicable to each class and series of long-term debt, including maturity date. If gain or loss resulted from a refunding transaction, include also the maturity date of the new issue.

2. In column (c) show the principal amount of bonds or other long-term debt reacquired.

3. In column (d) show the net gain or net loss realized on each debt reacquisition as computed in accordance with General Instruction 17 of the Uniform System of Accounts.

Line No.	Designation of Long-Term Debt (a)	Date Reacquired (b)	Princ. Amt. Of Debt Reacquired (c)	Net Gain or Net Loss (d)
1	7.2% Series First Mortgage Bonds. Due 2/2024.	4/2004	30,000,000	(1,270,107)
2	No Replacement Debt Issued - Amort thru 2/1/2024			
3				
4	7.5% Series First Mortgage Bonds. Due 3/2024.	4/2004	25,000,000	(1,097,914)
5	No Replacement Debt Issued - Amort thru 3/1/2024			
6				
7	7.0% Pollution Control Revenue Bonds	11/2003	25,000,000	(925,152)
8	Lawrenceburg, IN Series Due 4/2015			
9	Replaced by 2.625% Lawrenceburg Bonds Due 10/2019			
10	Loss being amortized over life of replacement debt			
11				
12	5.9% Pollution Control Revenue Bonds, due 11/2021	11/2004	52,000,000	(1,449,838)
13	City of Lawrenceberg, Indiana. (Replaced by VAR%			
14	Lawrenceberg, IN Bonds due 11/2021.)			
15				
16	9-1/4% Pollution Control Revenue Bonds, due 8/2014	8/1995	50,000,000	(2,677,532)
17	City of Rockport, Indiana.			
18	Replaced by 6.55% Rockport Bonds due 6/2025			
19	Replaced 5/06 by VAR% Rockport Bonds Due 6/2025,			
20	with $500,000 premium paid for early redemption			
21				
22	VAR% Pollution Control Revenue Bonds, due 8/2014	8/1995	50,000,000	(785,290)
23	City of Rockport, Indiana.			
24	Replaced by VAR% Rockport Bonds due 6/2025			
25				
26	9.00% Pref Stock Subject to Mandatory Redemption	4/1993	40,000,000	(896,000)
27	8.60% Pref Stock Subject to Mandatory Redemption	12/1993	40,000,000	(864,000)
28	8.68% Pref Stock Subject to Mandatory Redemption	1/1994	30,000,000	(540,000)
29	7.76% Pref Stock Subject to Mandatory Redemption	3/1994	35,000,000	(798,000)
30	6.875% Pref Stock Subject to Mandatory Redemption	1/2005	15,750,000	
31	5.90% Pref Stock Subject to Mandatory Redemption	1/2005	13,200,000	(861,392)
32	6.25% Pref Stock Subject to Mandatory Redemption	1/2005	19,250,000	
33	6.30% Pref Stock Subject to Mandatory Redemption	1/2005	13,245,000	
34	(Balance transferred from FERC Acct 210 to 189)			
35				
36	7.6% Pollution Control Revenue Bonds	11/2003	40,000,000	(1,209,363)
37	Rockport, IN Series Due 03/2016			
38	Replaced by 2.625% Rockport IN Bonds Due 04/2025			
39	Loss being amortized over life of replacement debt			
40				
41	VAR % Pollution Control Revenue Bonds, due 10/2019	5/2008	25,000,000	(323,600)
42	Series F Lawrenceburg			
43	Remarketed as Series I VAR%			(134,515)
44				
45	VAR % Pollution Control Revenue Bonds, due 11/2021	5/2008	52,000,000	(1,013,352)
46	Series G Lawrenceburg			
47	Remarketed as Series H VAR%			(261,800)

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2018

UNAMORTIZED LOSS AND GAIN ON REACQUIRED DEBT (Account 189, 257) (Continued)

4. Show loss amounts in red or by enclosure in parentheses.
5. Explain any debits and credits other than amortization debited to Account 428.1, Amortization of Loss on Reacquired Debt or credited to Account 429.1, Amortization of Gain on Reacquired Debt-Credit.

Balance Beginning of Year (e)	Debits During Year (f)	Credits During Year (g)	Balance End of Year (h)	Line No.
512,850		84,304	428,546	1
				2
				3
728,552		118,144	610,408	4
				5
				6
101,188		57,822	43,366	7
				8
				9
				10
				11
326,924		85,285	241,639	12
				13
				14
				15
1,045,177		140,922	904,255	16
				17
				18
				19
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				21
194,682		26,250	168,432	22
				23
				24
				25
153,559		30,712	122,847	26
				27
				28
				29
				30
				31
				32
				33
				34
				35
407,809		56,250	351,559	36
				37
				38
				39
				40
49,967		28,553	21,414	41
				42
28,731		15,671	13,060	43
				44
289,529		75,529	214,000	45
				46
94,825		24,737	70,088	47

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

UNAMORTIZED LOSS AND GAIN ON REACQUIRED DEBT (Account 189, 257)

1. Report under separate subheadings for Unamortized Loss and Unamortized Gain on Reacquired Debt, particulars of gain and loss on reacquisition applicable to each class and series of long-term debt, including maturity date. If gain or loss resulted from a refunding transaction, include also the maturity date of the new issue.

2. In column (c) show the principal amount of bonds or other long-term debt reacquired.

3. In column (d) show the net gain or net loss realized on each debt reacquisition as computed in accordance with General Instruction 16 of the Uniform System of Accounts.

Line No.	Designation of Long-Term Debt (a)	Date Reacquired (b)	Princ. Amt. Of Debt Reacquired (c)	Net Gain or Net Loss (d)
1	Early Redemption of $150M Series D Senior Unsecured Note	10/2010	150,000,000	(6,651,901)
2	Orginal Maturity Date of December 31, 2032			
3	Redeemed October 15, 2010			
4				
5	Early Redemption of $475M Series D Senior Unsecured Note	9/2018	475,000,000	(10,665,268)
6	Orginal Maturity Date of March 15, 2019			
7	Redeemed September 7, 2018			
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36	**SUBTOTAL Unamortized Losses**			
37				
38	7.35% Series First Mortgage Bonds. Due 7/2023.	6/2001	5,000,000	38,090
39	Partially reacquired and not refunded.			
40	Gain being amortized over life of retired debt.			
41				
42	**SUBTOTAL Unamortized Gains**			
43				
44	**TOTAL**			
45				
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2018

UNAMORTIZED LOSS AND GAIN ON REACQUIRED DEBT (Account 189, 257) (Continued)

4. Show loss amounts in red or by enclosure in parentheses.
5. Explain any debits and credits other than amortization debited to Account 428.1, Amortization of Loss on Reacquired Debt or credited to Account 429.1, Amortization of Gain on Reacquired Debt-Credit.

Balance Beginning of Year (e)	Debits During Year (f)	Credits During Year (g)	Balance End of Year (h)	Line No.
4,484,428		298,961	4,185,467	1
				2
				3
				4
0	10,665,268	118,504	10,546,764	5
				6
				7
				8
				9
				10
				11
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				35
8,418,221	**10,665,268**	**1,161,644**	**17,921,845**	36
				37
(9,843)	1,712	-	(8,131)	38
				39
				40
				41
(9,843)	**1,712**	**-**	**(8,131)**	42
				43
8,408,378	**10,666,980**	**1,161,644**	**17,913,714**	44
				45
				46
				47
				48
				49
				50

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 2018/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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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				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
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
						3
						4
						5
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						41
						42

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

CAPITAL STOCK SUBSCRIBED, CAPITAL STOCK LIABILITY FOR CONVERSION, PREMIUM ON CAPITAL STOCK AND INSTALLMENTS RECEIVED ON CAPITAL STOCK (Accounts 202 & 205, 203 & 206, 207, 212)

1. Show for each of the above accounts the amounts applying to each class and series of capital stock.
2. For Account 202, *Common Stock Subscribed,* and Account 205, *Preferred Stock Subscribed,* show the subscription price and the balance due on each class at the end of year.
3. Describe in a footnote the agreement and transactions under which a conversion liability existed under Account 203, *Common Stock Liability for Conversion,* or Account 206, *Preferred Stock Liability for Conversion*, at the end of the year.
4. For Premium on Account 207, *Capital Stock*, designate with a double asterisk any amounts representing the excess of consideration received over stated values of stocks without par value.

Line No.	Name of Account & Description of Item (a)	Number of Shares (b)	Amount (c)
1	Account 202 - Common Stock Subscribed		
2	None		
3			
4	Account 203 - Common Stock Liability for Conversion		
5	None		
6			
7	Account 205 - Preferred Stock Subscribed		
8	None		
9			
10	Account 206 - Preferred Stock Liability for Conversion		
11	None		
12			
13	Account 207 - Capital Stock		
14	Premium on Common Stock	1,400,000	4,234,635
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	TOTAL	1,400,000	4,234,635

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 2018/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		
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29		
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32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	976,661,804

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

SECURITIES ISSUED OR ASSUMED AND SECURITIES REFUNDED OR RETIRED DURING THE YEAR

1. Furnish a supplemental statement giving a brief description of security financing and refinancing transactions during the year and the accounting for the securities, discounts, premiums, expenses, and related gains or losses. Identify as to Commission authorization numbers and dates.
2. Furnish particulars (details) showing fully the accounting for the total principal amount, par value, or stated value of each class and series of security issued, assumed, retired, or refunded and the accounting for premiums, discounts, expenses, and gains or losses relating to the securities. Set forth the facts of the accounting clearly with regard to redemption premiums, unamortized discounts, expenses, and gains or losses relating to securities retired or refunded, including the accounting for such amounts carried in the respondent's accounts at the date of the refunding or refinancing transactions with respect to securities previously refunded or retired.
3. Include in the identification of each class and series of security, as appropriate, the interest or dividend rate, nominal date of issuance, maturity date, aggregate principal amount, par value or stated value, and number of shares. Give also the issuance of redemption price and name of the principal underwriting firm through which the security transactions were consummated.
4. Where the accounting for amounts relating to securities refunded or retired is other than that specified in General Instruction 16 of the Uniform System of Accounts, give references to the commission authorization for the different accounting and state the accounting method.
5. For securities assumed, give the name of the company for which the liability on the securities was assumed as well as particulars (details) of the transactions whereby the respondent undertook to pay obligations of another company. If any unamortized discounts, premiums, expenses, and gains or losses were taken over onto the respondent's books, furnish details of these amounts with amounts relating to refunded securities clearly earmarked.

1. Securities refunded or retired during 2018

Series	Due Date	Principal Amount	Date Retired
Local Bank Term Loan-Variable	05/14/2018	200,000,000	05/09/2018
Series I - 7.00% Fixed	03/15/2019	475,000,000	09/07/2018

2. Securities issued during 2018

Series	Due Date	Principal Amount	Date Issued
Local Bank Term Loan-Variable	05/09/2021	200,000,000	05/09/2018
Series M - 3.85% Fixed	05/15/2028	350,000,000	05/02/2018
Series N - 4.25% Fixed	08/15/2048	475,000,000	08/08/2018

3. Securities remarketed during 2018

Series	Due Date	Principal Amount	Date Remarketed
Series 2009A - 3.05% Fixed	06/01/2025	50,000,000	06/01/2018
Series 2009B - 3.05% Fixed	06/01/2025	50,000,000	06/01/2018

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 2018/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 D Pollution Control Bonds		17,500
3	SUBTOTAL - Account 222-Reacq PCRBs		17,500
4			
5	Account 223 - Advances From Associated Companies		
6	SUBTOTAL - Account 223-Advances From Assoc Co		
7			
8	Account 224 - Other Long Term Debt		
9	Spent Nuclear Fuel Disposal Costs Prior		
10	To April 7, 1983 - Basic Fee Assessment & Interest		
11			
12	Pollution Control Revenue Bonds		
13	Lawrenceburg, IN		
14	Series I - Variable Rate	25,000,000	178,919
15			179,337
16			
17	Series H - Variable Rate	52,000,000	331,889
18			277,847
19			
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			386,217
29			74,250
30			74,250
31			74,250
32			
33	TOTAL	3,343,802,388	44,626,066

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
04/04/2013	04/01/2025				-9,030	2
					-9,030	3
						4
						5
						6
						7
						8
						9
				273,606,302		10
						11
						12
						13
5/22/2008	10/1/2019	5/22/2008	10/1/2019	25,000,000	384,293	14
3/15/2017	10/1/2019	3/15/2017	10/1/2019			15
						16
5/20/2008	11/1/2021	5/20/2008	11/1/2021	52,000,000	799,255	17
3/9/2017	11/1/2021	3/9/2017	11/1/2021			18
						19
						20
4/25/2008	4/1/2025	4/25/2008	4/1/2025	40,000,000	820,000	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	1,375,000	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
				2,928,439,660	115,645,151	33

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 - 3.05% Fixed Rate	50,000,000	353,976
2			249,469
3			354,262
4			
5	Series 2009 B - 3.05% Fixed Rate	50,000,000	353,976
6			249,469
7			354,262
8			
9	Senior Unsecured Notes		
10	Series L - 3.75% Fixed Rate	300,000,000	3,139,683
11			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	Series M - 3.85% Fixed Rate	350,000,000	2,865,394
29	Per IURC Authority Cause #44904		1,102,500 D
30			
31	Series N - 4.25% Fixed Rate	475,000,000	4,926,878
32	Per IURC Authority Cause #45057		2,717,000 D
33	TOTAL	3,343,802,388	44,626,066

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	1,254,167	1
		6/1/2014	5/31/2018			2
6/1/2018	6/1/2025	6/1/2018	6/1/2025			3
						4
3/26/2009	6/1/2025	4/1/2009	5/31/2014	50,000,000	1,254,167	5
		6/1/2014	5/31/2018			6
6/1/2018	6/1/2025	6/1/2018	6/1/2025			7
						8
						9
6/29/2017	7/1/2047	6/29/2017	7/1/2047	300,000,000	11,250,000	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		421,741	19
						20
1/15/2009	3/15/2019	1/1/2009	2/28/2019		22,720,833	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		1,606,537	26
						27
5/2/2018	5/15/2028	5/2/2018	5/15/2028	350,000,000	8,945,903	28
						29
						30
8/8/2018	8/15/2048	8/8/2018	8/15/2048	475,000,000	8,018,924	31
						32
				2,928,439,660	115,645,151	33

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	Fort Wayne Settlement	26,802,388	
2			
3	Multiple Draw Term Loan	200,000,000	612,944
4	Variable Rate		
5			
6	Senior Unsecured Term Loan	200,000,000	508,528
7	Variable Rate		
8	SUBTOTAL - Acct 224 - Other Long Term Debt	3,343,802,388	44,608,566
9			
10			
11			
12			
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14			
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32			
33	TOTAL	3,343,802,388	44,626,066

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.
3/1/2010	2/28/2025	3/1/2010	2/28/2025	12,833,358		1
						2
5/14/2015	5/14/2018	6/1/2015	5/14/2018		2,091,889	3
						4
						5
5/9/2018	5/9/2021	5/9/2018	5/9/2021	200,000,000	4,311,472	6
						7
				2,928,439,660	115,654,181	8
						9
						10
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						30
						31
						32
				2,928,439,660	115,645,151	33

Schedule Page: 256 Line No.: 10 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.: 14 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.: 17 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. On the 6/1/2018 put date, the PCRB was converted to 3.05% with a maturity date of 6/1/2025. Issuance expenses totaling $354,262 will be amortized through 6/1/2025.

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. On the 6/1/2018 put date, the PCRB was converted to 3.05% with a maturity date of 6/1/2025. Issuance expenses totaling $354,262 will be amortized through 6/1/2025.

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.: 21 Column: a

The $475M 7% fixed rate Series I Senior Unsecured Note was redeemed early on 9/7/2018. Unamortized issuance expense of $163,928, discount expense of $157,451, and a cash premium of $10,343,889 was reclassified to Loss on Reacquired Debt and will be amortized through August 2048 which is the remaining life of the $475M 4.25% Series N Senior Unsecured Note.

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

The $350M 3.85% fixed rate Series M Senior Unsecured Note was issued 5/2/2018 with a maturity date of 5/15/2028. Issuance expense and discount expense will be amortized through May 2028.

Schedule Page: 256.1 Line No.: 31 Column: a

The $475M 4.25% fixed rate Series N Senior Unsecured Note was issued 8/8/2018 with a maturity date of 8/15/2048. Issuance expense and discount expense will be amortized through August 2048.

Schedule Page: 256.2 Line No.: 1 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: 256.2 Line No.: 3 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.

Schedule Page: 256.2 Line No.: 6 Column: a

The $200 million senior unsecured term loan was issued on May 9, 2018. The interest rate is variable and the maturity date is May 9, 2021.

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

PAYABLES TO ASSOCIATED COMPANIES* (Accounts 233, 234)

1. Report particulars of notes and accounts payable to associated companies at end of year.
2. Provide separate totals for Accounts 233, Notes Payable to Associated Companies, and 234, Accounts Payable to Associated Companies, in addition to total for the combined accounts.
3. List each note separately and state the purpose for which issued. Show also in column (a) date of note, maturity and interest rate.
4. Include in column (f) the amount of any interest expense during the year on notes or accounts that were paid before the end of the year.
5. If collateral has been pledged as security to the payment of any note or account, describe such collateral.

See definition on page 226B

Line No.	Particulars (a)	Balance Beginning of Year (b)	Totals for Year: Debits (c)	Totals for Year: Credits (d)	Balance End of Year (e)	Interest for Year (f)
1	Account 233					
2	AEP Utility Funding LLC	211,574,416	11,147,850,113	10,937,339,075	1,063,378	1,906,360
3	SUBTOTAL - Account 233	211,574,416	11,147,850,113	10,937,339,075	1,063,378	1,906,360
4	Account 234					
5	AEP I&M Transmission Company	336,597	6,586,871	6,584,080	333,806	
6	AEP Generating Company	22,830,981	303,609,065	300,314,465	19,536,381	
7	AEP Energy Partners	5,507	52,971	48,483	1,019	
8	AEP Onsite Partners	0	903	1,422	519	
9	AEP Service Corporation	26,762,031	316,741,124	313,758,476	23,779,383	
10	AEP System Pool (AEPSC)	44,773,453	1,096,619,915	1,074,357,369	22,510,907	
11	AEP Texas Central Company	3,459	451,073	454,909	7,295	
12	AEP Texas North Company	1,802	26,846	25,577	533	
13	AEP Utilities, Inc	0	79,492	79,492	0	
14	AEP Utility Funding LLC	42,009	55,019	90,832	77,822	
15	American Electric Power Co	137,881	574,586,823	574,911,587	462,645	
16	Appalachian Power Co	793,601	15,054,457	15,169,750	908,894	
17	Blackhawk Coal Company	4,795	84,204	84,598	5,189	
18	Cardinal Operating Company	50	6,767	6,717	0	
19	Cook Coal Terminal	2,017,844	36,885,733	36,673,844	1,805,955	
20	Dolet Hills Lignite Co, LLC	0	14,689	14,703	14	
21	Franklin Real Estate Company	0	19,359	19,359	0	
22	Indiana Franklin Realty, Inc	0	203,074	203,074	0	
23	Kentucky Power Co	12,285	1,436,333	1,722,990	298,942	
24	Kingsport Power Co	0	288,572	290,606	2,034	
25	Ohio Power Co	340,024	26,883,652	26,888,716	345,088	
26	Public Service Co of OK	28,830	1,223,602	1,203,388	8,616	
27	Southwestern Electric Power Co	156,374	5,654,623	5,591,504	93,255	
28	United Sciences Testing, Inc	304	71,488	71,184	0	
29	Wheeling Power Co	12,054	317,846	305,815	23	
30	Ohio PPA Plants	0	362	362	0	
31	AEP Credit, Inc.	16,030	147,384	136,772	5,418	
32	AEP Transmission Companies - Various	5,858	937,088	931,951	721	
33	SUBTOTAL - Account 234	98,281,769	2,388,039,335	2,359,942,025	70,184,459	0
34	TOTAL	309,856,185	13,535,889,448	13,297,281,100	71,247,837	1,906,360

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2018

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-1of 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 filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. Statenames of group members, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.

Line No.		TOTAL AMOUNT
1	Utility net operating income (page 114 line 26)	368,464,374
2	Allocations:	
3	Net Other Income and Deductions	12,052,826
4	Interest Charges	119,215,543
5	Net income for the year (page 117 line 78)	261,301,657
6	Allocation of Net income for the year (see footnote)	
7	Add: Federal income tax expenses	
8		
9	Total pre-tax income	
10		
11	Add: Taxable income not reported on books:	
12		
13		
14		
15	Add: Deductions recorded on books not deducted from return	
16		
17		
18		
19	Subtract: Income recorded on books not included in return:	
20		
21		
22		
23	Subtract: Deductions on return not charged against book income:	
24		
25		
26	Federal taxable income for the year	188,249,309

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES (Continued)

3. Allocate taxable income between utility and other income as required to allocate tax expense between 409.1 and 409.2
4. A substitute page, designed to meet a particular need of a company, may be used as long as data is consistent and meets the requirements of the above instructions.

Utility	Other	Line No.
368,464,374	[redacted]	1
	[redacted]	2
12,052,826	[redacted]	3
119,215,543	[redacted]	4
[redacted]	[redacted]	5
		6
		7
		8
		9
		10
		11
		12
		13
		14
		15
		16
		17
		18
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		20
		21
		22
		23
		24
		25
188,249,309		26

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2018

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)	
261A	6			In (000's)
			Net Income for the year page 117	261,302
			Federal Income Taxes	12,052
			State and Local Income Taxes	16,968
			PreTax Book Income	290,322
			Increase (Decrease) in Taxable Income resuliting from:	
			Excess tax vs book depreciation	(367,548)
			Afudc / interest capitalized	(4,344)
			Percent repair allowance	(22,632)
			Removal costs	(60,462)
			Accelerated amortization	(2,484)
			Property tax adjustments	2,366
			Revenue refunds	(35)
			Deferred fuel costs	14,897
			Equity in earnings of subsidiaries	(256)
			Book accruals	1,846
			Book deferrals	(93,135)
			Other miscellaneous	348,631
			Tax accruals	3,333
			Tax deferrals	(22,535)
			Tax vs book gain / loss	(3,707)
			Nuclear fuel adjustments	35,213
			Nuclear fuel disposal costs	(4,271)
			Nuclear decommissioning costs	57,667
			Book deferred nuclear costs	29,186
			Mark-to-market adjustments	(646)
			Emission allowances	1,323
			Total for PERMANENT SCHEDULE M's:	(3,410)
			Federal Tax Net Income - Estimated Current Year Taxable Income (Separate Return Basis)	199,319
			Current State Income Taxes	11,070
			Federal Taxable Income	188,249
			Computation Tax*	
			Federal Income Tax on Current Year Taxable Income (Separate Return Basis) at Statutory Rate of 21%	39,532
			Adjustment due to System Consolidation (a)	(2,320)
			Estimated Taxes Currently Payable	37,212
				-
			Tax Credit C/F	(13,213)
			NOL Reclass	(10,394)
			Alternative Minimum Tax Credits	(70)
			FIN48 Perm Items	-
			Non-FIN48 Perm Items	-
			Adjustment of Prior Years Accruals(Net)	45,177
			Estimated Current Year Federal Income Taxes (Net)	58,712

(a) 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 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 subsidiaries with taxable income. With the 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 2018 System Federal income taxes will not be available until the consolidated Federal income tax return is completed and filed by October 2019. 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 is filed.

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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 2018/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	-48,374,528		54,325,354	32,476,801	
3	FED INCOME TAX FIN48	-627,172			-627,172	
4	FIT IRS AUDIT	-3,748,795		2,110,011	-3,748,795	-2,110,011
5	FICA - 2018	2,346,066		19,114,264	18,417,928	
6	UNEMPLOYMENT - 2018	49,359		117,340	112,609	
7	EXCISE TAX - 2017	264,200		5,727	269,927	
8	EXCISE TAX - 2018			1,204,208	905,584	
9	SUBTOTAL Federal	-50,090,870		76,876,904	47,806,882	-2,110,011
10						
11	STATE OF INDIANA:					
12	INCOME 2015					
13	INCOME 2017	-8,869,357		4,479,499		
14	INCOME 2018			8,483,026	-59,001	
15	UNEMPLOYMENT IN - 2018	22,689		65,218	71,461	
16	UTIL RECEIPTS TAX - 2017			-135,939	-135,939	
17	UTIL RECEIPTS TAX - 2018			20,674,000	20,674,000	
18						
19	INDIANA LICENSE TAX			32	32	
20	SALES & USE TAX - 2017	768,393		-51,533	716,860	
21	SALES & USE TAX - 2018			4,633,054	4,108,938	
22						
23	PUBLI SERV COMM-2017		434,188	868,375	434,187	
24	PUBLI SERV COMM-2018			774,550	1,161,825	
25						
26	REAL & PERS PROP-2016					
27	REAL & PERS PROP-2017	17,863,384		-485,727	17,377,657	
28	REAL & PERS PROP-2018			18,519,090	11,723	
29						
30	PERS PROP LEASED-2017	583,650		58,183	641,833	
31	PERS PROP LEASED-2018			627,900		
32						
33	REAL PROP LEASED-2018			227,934	227,934	
34						
35	SUBTOTAL Indiana	10,368,759	434,188	58,737,662	45,231,510	
36						
37						
38						
39						
40	STATE OF KENTUCKY:					
41	TOTAL	21,741,646	1,192,599	186,897,935	143,923,558	-2,110,011

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
-26,525,975		63,510,915			-9,185,561	2
						3
		2,110,011				4
3,042,402		12,321,802			6,792,462	5
54,090		76,431			40,909	6
		942			4,785	7
298,624		10,236			1,193,972	8
-23,130,859		78,030,337			-1,153,433	9
						10
						11
		-59,001			59,001	12
-4,389,858		4,392,772			86,727	13
8,542,027		8,631,610			-148,584	14
16,446		43,894			21,324	15
		-135,939				16
		20,674,000				17
						18
		32				19
					-51,533	20
524,116					4,633,054	21
						22
		868,375				23
	387,275	774,550				24
						25
		-167,154			167,154	26
		-478,016			-7,711	27
18,507,367		17,914,506			604,584	28
						29
		58,183				30
627,900		627,900				31
						32
					227,934	33
						34
23,827,998	387,275	53,145,712			5,591,950	35
						36
						37
						38
						39
						40
66,634,648	5,221,195	176,802,977			10,094,958	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 2018/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	KY FRANCHISE 2017			9,767		
2	KY INCOME 2017	-157,733		10,495		
3	KY INCOME 2018			87,492		
4	Subtotal Kentucky	-157,733		107,754		
5	STATE OF MICHIGAN:					
6	MI INCOME 2017	-1,609,328		601,063		
7	MI INCOME 2018			1,853,072		
8	MI SBT					
9	MI CITIES	-1,261				
10	UNEMPLOYMENT - 2018	168,654		389,862	382,516	
11	PUBL SERV COMM'S-2017		165,225	605,233	4,400,008	
12	PUBL SERV COMM'S-2018			254,775	476,337	
13	USE TAX-2017	295,948	90,374	5,931	211,505	
14	USE TAX - 2018			1,594,807	1,454,176	
15	USE TAX - REFUNDS			-131,301	-131,301	
16	SALES TAX - 2017		502,812		-502,812	
17	SALES TAX - 2018				576,960	
18	FUEL REFUNDS - 2018			-10,393	-10,393	
19	REAL & PERS PROP-2012					
20	REAL & PERS PROP-2015			483	483	
21	REAL & PERS PROP-2016	11,726,419		-141,402	11,585,017	
22	REAL & PERS PROP-2017	45,351,975		-1,594,823	31,791,817	
23	REAL & PERS PROP-2018			47,122,700		
24						
25	PERS PROP LEASED-2016	19,443		-11,515	7,928	
26	PERS PROP LEASED-2017	59,967			29,367	
27	PERS PROP LEASED-2018			50,199		
28						
29	REAL PROP LEASED-2016	30,772		-1,953	28,819	
30	REAL PROP LEASED-2017			196,000	169,665	
31						
32	SUBTOTAL Michigan	56,042,589	758,411	50,782,738	50,470,092	
33						
34	DE License Tax			300	300	
35	SUBTOTAL DELAWARE			300	300	
36						
37						
38						
39						
40						
41	TOTAL	21,741,646	1,192,599	186,897,935	143,923,558	-2,110,011

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 2018/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)	
9,767		1,884			7,883	1
-147,238		13,202			-2,707	2
87,492		88,410			-918	3
-49,979		103,496			4,258	4
						5
-1,008,265		639,325			-38,262	6
1,853,072		1,872,161			-19,089	7
						8
-1,261						9
176,000		318,338			71,524	10
	3,960,000	605,233				11
	221,562	254,775				12
		8,403			-2,472	13
216,029	75,398	113,610			1,481,197	14
		-7,840			-123,461	15
						16
	576,960					17
					-10,393	18
		7,005			-7,005	19
		-181,373			181,856	20
		21,174			-162,576	21
11,965,335		41,104,618			-42,699,441	22
47,122,700		65,333			47,057,367	23
						24
		-11,515				25
30,600		59,967			-59,967	26
50,199					50,199	27
						28
		-1,953				29
26,335		196,000				30
						31
60,430,744	4,833,920	45,063,261			5,719,477	32
						33
		300				34
		300				35
						36
						37
						38
						39
						40
66,634,648	5,221,195	176,802,977			10,094,958	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 2018/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						
3						
4	STATE OF WEST VIRGINIA:			26	26	
5	LICENSE TAX					
6	WV FRANCHISE-2013					
7	WV FRANCHISE-2014					
8	WEST VA INC TAX-2014					
9	WEST VA INC TAX-2014					
10	WEST VA INC TAX-2016					
11	WEST VA INC TAX-2017	981,502		-414,039	-770,000	
12	WEST VA INC TAX-2018			257,890	130,000	
13						
14						
15	REAL & PERS PROP-2016					
16	REAL & PERS PROP-2017	13,000		-4,403	8,597	
17						
18	WV USE TAX - 2017	1,398			1,398	
19	WV USE TAX - 2018			46,141	42,372	
20	WV EXCISE TAX - 2017	41,271		7	41,278	
21	WV EXCISE TAX - 2018			216,469	164,152	
22						
23	UNEMPLOYMENT - 2018	729		40,721	41,120	
24	SUBTOTAL West Virginia	1,037,900		142,812	-341,057	
25						
26	STATE OF OHIO:					
27	OHIO FRANCH TAX - 2008					
28	OHIO CITY INCOME TAX -				500	
29	OHIO CAT TAX - 2017	26,100		-30,866	-4,766	
30	OHIO CAT TAX - 2018			69,319	67,519	
31						
32	State Unemployment 2018	151		-151		
33	SUBTOTAL Ohio	26,251		38,302	63,253	
34	STATE OF ILLINOIS:					
35	IL INCOME TAX - 2012					
36	IL INCOME TAX - 2016	-62,615		62,615		
37	IL INCOME TAX - 2017	-241,706		43,321		
38	IL INCOME TAX - 2018			375,107		
39	SUBTOTAL Illinois	-304,321		481,043		
40	STATE OF LOUISIANA:					
41	TOTAL	21,741,646	1,192,599	186,897,935	143,923,558	-2,110,011

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 2018/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
		26				5
						6
						7
						8
						9
		-153			153	10
1,337,463		-281,679			-132,360	11
127,890		260,541			-2,651	12
						13
						14
		3,428			-3,428	15
		6,570			-10,973	16
						17
						18
3,769					46,141	19
					7	20
52,317					216,469	21
						22
370		-7,549			48,270	23
1,521,809		-18,816			161,628	24
						25
						26
						27
-500						28
		-30,866				29
1,800		69,319				30
						31
		-151				32
1,300		38,302				33
						34
		14,936			-14,936	35
					62,615	36
-198,385		46,357			-3,036	37
375,107		379,094			-3,987	38
176,722		440,387			40,656	39
						40
66,634,648	5,221,195	176,802,977			10,094,958	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 2018/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	LA Franchise Tax					
2						
3	SUBTOTAL Louisiana					
4						
5	STATE OF PA:					
6	PA Gross Receipts Audit	239,325				
7						
8	SUBTOTAL Pennsylvania	239,325				
9						
10	RAILCAR PROP TAX:					
11	Misc States - 2017			15,446	15,446	
12	Misc States - 2018			28,781	28,781	
13	SUBTOTAL Railcar Prop Tax			44,227	44,227	
14						
15	STATE OF MISSOURI					
16	UNEMPLOYMENT - 2017					
17	MO INCOME TAX - 2017	-847		-317		
18	MO INCOME TAX - 2018			255		
19	MO FRANCHISE					
20	SUBTOTAL Missouri	-847		-62		
21						
22	MISC RTD PROP TX-2016	274,246		-274,246		
23	MISC RTD PROP TX-2017	1,147,552		-39,544		
24						
25	STATE INCOME TAX FIN-48	3,158,795			648,306	
26						
27	MICHIGAN LICENSE TAX			25	25	
28	VARIOUS LICENSE TAX			20	20	
29						
30	VARIOUS FRANCHISE TAX					
31						
32	SIT LONG TERM					
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	21,741,646	1,192,599	186,897,935	143,923,558	-2,110,011

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 2018/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
239,325						6
						7
239,325						8
						9
						10
					15,446	11
					28,781	12
					44,227	13
						14
						15
						16
-1,164		-305			-12	17
255		258			-3	18
						19
-909		-47			-15	20
						21
					-274,246	22
1,108,008					-39,544	23
						24
2,510,489						25
						26
		25				27
		20				28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
66,634,648	5,221,195	176,802,977			10,094,958	41

Schedule Page: 262   Line No.: 4   Column: f

This adjustment is for FIN 48 deferred taxes in the payables account that had an offset to accounts 410.1 and 411.1 in the amount of ($2,110,011).

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.

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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 2018/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%	24,136,393			4114	4,686,927	
6	30%	9,939,234					
7							
8	TOTAL	34,075,627				4,686,927	
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							
23							
24							
25							
26							
27							
28							
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32							
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42							
43							
44							
45							
46							
47							
48							

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
19,449,466			5
9,939,234			6
			7
29,388,700			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

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

Remaining amortization period is 20 years.

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

MISCELLANEOUS CURRENT AND ACCRUED LIABILITIES (Account 242)

1. Give description and amount of other current and accrued liabilities as of the end of year.
2. Minor items may be grouped by classes, showing number of items in each class.

Line No.	Item (a)	Balance End of Year (b)
1	Accrued Incentive Plans	38,501,748
2	Accrued Vacation, Holiday, and Other Non-Productive	20,102,143
3	Accrued Payroll	9,019,414
4	Payroll Deductions	614,740
5	Miscellaneous Employee Benefits (2 Items)	1,790,245
6	Accrued Workers Compensation	352,663
7	Accrued Lease/Rents	19,152,389
8	Accrued Revenue Refunds	255,841
9	Control Cash Disbursements	4,101,751
10	Accrued Civil Penalties	751,034
11	Miscellaneous Current & Accrued Liabilities (9 Items)	675,431
12	Environmental Accruals	88,381
13	IN Comm Action & Neighbor to Neighbor Programs	175,000
14		
15		
16		
17		
18		
19		
20	TOTAL	95,580,780

CUSTOMER ADVANCES FOR CONSTRUCTION (Account 252)

Line No.	List Advances by department (a)	Balance End of Year (b)
21	None	
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39	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 2018/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	18,284,501	507	3,706,716		14,577,785
2	Amtz Period 12/1989-12/2022					
3						
4	Pole Attachment Rentals	591,679	454	1,829,304	1,851,717	614,092
5						
6	IPP-System Upgrade Credits	3,329,542			155,635	3,485,177
7						
8	Defd Gain-Fiber Optics Agrmt	3,700,485	411.6	324,108		3,376,377
9	In Kind Service-Amrtz thru 2025					
10						
11	Deferred Revenues-Verizon	249,059	451	47,439		201,620
12	Amortized thru March 2023					
13						
14	Deferred Revenues-KDL	42,270	451	9,348		32,922
15	Amortized thru Dec 2022					
16						
17	Customer Advance Receipts	6,176,200	142	6,176,200	5,806,046	5,806,046
18						
19	Federal Mitigation Deferral (NSR)	2,052,907				2,052,907
20						
21	Deferred Revenue	37,279	451	37,279	505,712	505,712
22						
23	Contract Settlement Reserves	43,259	186	137,304	502,252	408,207
24						
25	Asbestos Accrual		925	33,335	349,208	315,873
26						
27	Minor Items	343,668	Various	626,345	592,679	310,002
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	34,850,849		12,927,378	9,763,249	31,686,720

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 2018/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	29,431,106	12,516,230	12,490,883
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	29,431,106	12,516,230	12,490,883
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	-11,772,442		
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	17,658,664	12,516,230	12,490,883
18	Classification of TOTAL			
19	Federal Income Tax	17,658,664	12,516,230	12,490,883
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 2018/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.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
						29,456,453	4
							5
							6
							7
						29,456,453	8
							9
							10
							11
							12
							13
							14
							15
				Various	79,999	-11,692,443	16
					79,999	17,764,010	17
							18
					79,999	17,764,010	19
							20
							21

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 2018/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 (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 282			
2	Electric	1,379,310,544	1,504,670,071	1,470,416,556
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,379,310,544	1,504,670,071	1,470,416,556
6	Non-Utility	338,543	373,846	428,119
7	SFAS 109/FIN 48	-493,145,740		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	886,503,347	1,505,043,917	1,470,844,675
10	Classification of TOTAL			
11	Federal Income Tax	886,503,347	1,505,043,917	1,470,844,675
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 2018/Q4

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

3. 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
						1,413,564,059	2
							3
							4
						1,413,564,059	5
						284,270	6
		Various	1,337,351,461	Various	1,392,436,454	-438,060,747	7
							8
			1,337,351,461		1,392,436,454	975,787,582	9
							10
			1,337,351,461		1,392,436,454	975,787,582	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 2018/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	27,230,697	6,303,406	15,705,359
4	Reg Asset - SFAS 143 - ARO	775,948,403	33,988,863	356,501,875
5	Deferred Cook O&M Restart Cost	23,331,520	6,356,994	21,818,705
6	Nuclear Fuel	5,201,356	197,955,746	207,663,363
7	Mark To Market	-2,147,400	8,798,681	5,767,545
8	Other	86,679,328	100,116,380	129,816,859
9	TOTAL Electric (Total of lines 3 thru 8)	916,243,904	353,520,070	737,273,706
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	230,027,028		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	1,146,270,932	353,520,070	737,273,706
20	Classification of TOTAL			
21	Federal Income Tax	965,916,191	362,435,470	750,428,367
22	State Income Tax	180,354,741		
23	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 2018/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						
		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
							2
						17,828,744	3
						453,435,391	4
						7,869,809	5
						-4,506,261	6
						883,736	7
5,432,040	9,764,104					52,646,785	8
5,432,040	9,764,104					528,158,204	9
							10
							11
							12
							13
							14
							15
							16
							17
3,483,360	3,390,557	Various	322,629,279	Various	292,749,497	200,240,049	18
8,915,400	13,154,661		322,629,279		292,749,497	728,398,253	19
							20
			309,304,151		275,270,212	543,889,355	21
			13,325,128		17,479,285	184,508,898	22
							23

NOTES (Continued)

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

	Balance at Beginning of Year	Balance at End of Year
NON-UTILITY	973,289	1,066,093
SFAS 109	229,053,739	199,173,956
Total Line 18	230,027,028	200,240,049

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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 2018/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	(5,437,238)	456	3,932,496	6,732,866	-2,636,868
2						
3	Netting of Trading Activities Related to	5,437,238	182	6,673,119	7,432,136	6,196,255
4	Unrealized Gains/Losses on Forward Commitments					
5	Between Regulated Assets/Liabilities					
6						
7	Asset Retirement Oblig-Excess Provision SFAS 143	945,026,447	228	261,454,191	144,919,062	828,491,318
8						
9	SNF Trust Funds - Pre 4/83	43,157,302	Various	9,231,351	8,967,882	42,893,833
10						
11	Gains on Foreign Currency Derivatives	67,854	403	11,309		56,545
12	Amortz 1/2009 - 12/2023					
13						
14	SFAS 109 Deferred FIT	738,930,833	Various	1,615,499,369	1,600,252,635	723,684,099
15						
16	DSI Federal Mandate Rider - Indiana	386,558	Various	478,328	2,258,354	2,166,584
17	Per IURC Cause No. 44331					
18						
19	Cook Life Cycle Management - Indiana	2,396,734	Various	9,762,319	7,365,585	
20	Per IURC Cause No. 44182					
21						
22	Indiana Clean Coal Technology Rider	486,021	Various	2,630	1,120,001	1,603,392
23	Per IURC Cause No. 44523					
24						
25	Distribution Storm Expense	3,969,136	593	2,303,039	4,047,529	5,713,626
26	Per IURC Cause No. 44075					
27						
28	Over Recovered Fuel Costs - Indiana	2,655,795	182.3	2,655,795	22,852,752	22,852,752
29						
30	Michigan Renewable Energy Surcharge	2,732,127	Various	2,724,053	6,200,433	6,208,507
31						
32	Capacity Settlement - IN Portion	1,401,549	447	7,972	1,935,706	3,329,283
33	Per IURC Cause No. 44075					
34						
35	Other Comprehensive Inc - Excess Def FIT	(2,300,609)			2,300,609	
36						
37	PJM Trans Enhancement		565	15,080,146	44,156,705	29,076,559
38						
39	Michigan Over Recovered Fuel Costs				4,548,450	4,548,450
40						
41	TOTAL	1,738,909,747		1,930,883,094	1,867,475,890	1,675,502,543

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 2018/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Indiana RAR Over Recovery		555	1,066,977	2,385,185	1,318,208
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
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31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	1,738,909,747		1,930,883,094	1,867,475,890	1,675,502,543

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2018

GAIN OR LOSS ON DISPOSITION OF PROPERTY (Account 421.1 and 421. 2)

1. Give a brief description of property creating the gain or loss. Include name of party acquiring the property (when acquired by another utility or associated company) and the date transaction was completed. Identify property by type: Leased, Held for Future Use, or Nonutility.
2. Individual gains or losses relating to property with an original cost of less than $100,000 may be grouped with the number of such transactions disclosed in column (a).
3. Give the date of Commission approval of journal entries in column (b), when approval is required. Where approval is required but has not been received, give explanation following the item in column (a). (See account 102, Utility Plant Purchased or Sold.)

Line No.	Description of Property (a)	Original Cost of Related Property (b)	Date Journal Entry Approved (When Required) (c)	Account 421.1 (d)	Account 421.2 (e)
1	Gain on disposition of property:				
2					
3	Sale of Utility Property				
4					
5	Two (2) properties with original cost	79,741		256,869	
6	less than $100,000				
7					
8	Sale of Non-Utility Property				
9					
10	Two (2) properties with original cost	2		685,000	
11	less than $100,000				
12					
13					
14	Sale of Other Property				
15					
16					
17					
18	Sale of Miscellaneous Equipment				
19					
20					
21	Total Gain	79,743		941,869	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2018

GAIN OR LOSS ON DISPOSITION OF PROPERTY (Account 421.1 and 421.2) (Continued)

Line No.	Description of Property (a)	Original Cost of Related Property (b)	Date Journal Entry Approved (When Required) (c)	Account 421.1 (d)	Account 421.2 (e)
28	Loss on disposition of property:				
29					
30	Sale of Utility Property				
31					
32					
33					
34					
35	Sale of Non-Utility Property				
36	Eighteen (18) properties each with original	177,806			76,361
37	cost less than $100,000				
38					
39					
40					
41					
42					
43	Total Loss	177,806			76,361

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

PARTICULARS CONCERNING CERTAIN OTHER INCOME ACCOUNTS

1. Report in this schedule the information specified in the instructions below for the respective other income accounts. Provide a conspicuous subheading for each account and show a total for the account. Additional columns may be added for any account if deemed necessary.
2. Merchandising, Jobbing and Contract Work (Accounts 415 and 416) - Describe the general nature of merchandising, jobbing and contract activities. Show revenues by class of activity, operating expenses classified as to operation, maintenance, depreciation, rents and net income before taxes. Give the bases of any allocations of expenses between utility and merchandising, jobbing and contract work activities.
3. Nonutility Operations (Accounts 417 and 417.1) - Describe each nonutility operation and show revenues, operating expenses classified as to operation, maintenance, depreciation, rents, amortization, and net income before taxes, from the operation. Give the bases of any allocations of expenses between utility and nonutility operations. The book cost of property classified as nonutility operations should be included in Account 121.
4. Nonoperating Rental Income (Account 418) - For each major item of miscellaneous property included in Account 121, Nonutility Property, which is not used in operations for which income is included in Account 417, but which is leased or rented to others, give name of lessee, brief description of property, effective date and expiration date of lease, amount of rent revenues, operating expenses classified as to operation, maintenance, depreciation, rents, amortization, and net income, before taxes, from the rentals. If the property is leased on a basis other than that of a fixed annual rental, state the method of determining the rental. Minor items may be grouped by classes, but the number of items so grouped should be shown. Designate any lessees which are associated companies.
5. Equity in earnings of subsidiary companies (Account 418.1) - Report the utility's equity in the earnings or losses of each subsidiary company for the year.
6. Interest and Dividend Income (Account 419) - Report interest and dividend income, before taxes, identified as to the asset account or group of accounts in which are included the assets from which the interest or dividend income was derived. Income derived from investments, Accounts 123, 124 and 136 may be shown in total. Income from sinking and other funds should be identified with the related special funds. Show also expenses included in Account 419 as required by the Uniform System of Accounts.
7. Miscellaneous Nonoperating Income (Account 421) - Give the nature and source of each miscellaneous nonoperating income, and expense and the amount for the year. Minor items may be grouped by classes.

Line No.	Item (a)	Amount (b)
1	Accounts 415 & 416 - Other Income - Merchandising,	
2	Jobbing, and Contract Work	
3	- Income	0
4	- Costs and Expenses	0
5	Total Accounts 415 & 416	0
6		
7	Account 417 - Nonutility Operations	
8	Water Transportation	
9	-Revenues	72,961,712
10	-Expenses - Operation	(60,390,121)
11	-Maintenance	(5,810,428)
12	-Depreciation, Depletion, and Amortization	(908,401)
13	-Other	0
14	Total Account 417	5,852,762
15		
16	Account 418 - Nonoperating Rental Income	
17	-Rent Revenue	294,723
18	-Expense	(7,058)
19	-Other	0
20	Total Account 418	287,665
21		
22	Account 418.1 - Equity in Earnings of Subsidiary Companies	255,753
23		
24	Account 419 - Interest and Dividend Income	
25	- Communications Leases	506,651
26	- Margin Interest	64,911
27	- Use Tax Refund MI Industrial Proc Exemption	3,410
28		

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/18

PARTICULARS CONCERNING CERTAIN OTHER INCOME ACCOUNTS

Line No.	Item (a)	Amount (b)
1	- Other	119,192
2	- Income Taxes	392,928
3	- Associated Companies	1,991,540
4	- Dedicated East Sales	50,263
5		
6	Total Account 419	3,128,895
7		
8		
9	Account 419.1 - Allowance for Funds Used During Contruction	11,901,253
10		
11	Account 421 - Miscellaneous Nonoperating Income	
12		
13		
14	- Michigan Energy Optimization Carry Charge	22,406
15	- Indiana Base Case Amortization	(421,713)
16	- Indiana Turbine Replacement Carrying Charge	1,101,103
17	- Michigan Turbine Replacement Carrying Charge	147,113
18	- Regional Transmission Organization Carrying Charges	55,462
19	- Michigan Base Case Amortization	(1,152,723)
20	- Rents	26,121
21	- Indiana Life Cycle Management Carry Charge	1,883,581
22	- Indiana Rockport Dry Sorbent Injection	554,126
23	- Michigan Life Cycle Management Carry Charge	1,756,998
24	- Michigan Renewable Energy Purchase Agreement	(787)
25	- Other	134,878
26		
27		
28		
29	Total Account 421	4,106,565
30		
31	Account 421.1 - Gain on Disposition of Property	941,869
32		
33	Account 421.2 - Loss on Disposition of Property	(76,361)
34		
35		
36		
37		
38		
39		
40	Total Other Income	26,398,401
41		
42		
43		
44		
45		

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account.
2. 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.
3. If increases or decreases from pervious year (columns (c), (e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES Amount for Year (b)	 Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	153,777,745	129,581,703
3	(442) Commercial and Industrial Sales		
4	Small (or Commercial)	89,633,487	82,697,677
5	Large (or Industrial)	72,892,103	69,812,708
6	(444) Public Street and Highway Lighting	1,214,349	1,316,387
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	(449) Other Sales		
11			
12	TOTAL Sales to Ultimate Consumers	317,517,684	283,408,475
13			
14	(447) Sales for Resale	50,030,761	44,070,176
15	TOTAL Sales of Electricity	367,548,445 *	327,478,651
16			
17	(Less) (449.1) Provision for Rate Refunds	10,116,021	1,085,910
18	TOTAL Revenue Net of Provision for Refunds	**357,432,424**	**326,392,741**
19	Other Operating Revenues		
20	(450) Forfeited discounts	875,684	712,924
21	(451) Miscellaneous Service Revenues	763,830	702,284
22	(453) Sales of Water and Water Power		
23	(454) Rent from Electric Property	1,078,146	1,049,088
24	(455) Interdepartmental Rents		
25	(456) Other Electric Revenues	5,317,936	4,296,211
26			
27			
28			
29			
30	TOTAL Other Operating Revenues	8,035,596	6,760,507
31			
32	TOTAL Electric Operating Revenues	**365,468,020**	**333,153,248**

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/18

ELECTRIC OPERATING REVENUES (Account 400) (Continued)

4. 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 footnote.)
5. See Page 108, Important Changes During Year, for important new territory added and important rate increases or decreases.
6. For line 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by account.
7. Include unmetered sales. Provide details of such sales in a footnote.

MEGAWATT HOURS SOLD		AVERAGE NUMBER OF CUSTOMERS PER MONTH		
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number or Previous Year (g)	Line No.
				1
1,220,950	1,145,585	110,179	109,725	2
[redacted]				3
814,097	810,742	17,969	17,629	4
813,899	813,521	921	934	5
10,564	10,649	349	344	6
				7
				8
				9
				10
				11
2,859,510	2,780,497	129,418	128,632	12
				13
612,866	598,731	5	5	14
3,472,376 **	3,379,228	129,423	128,637	15
				16
				17
3,472,376	3,379,228	129,423	128,637	18

* Includes ($930,640) unbilled revenues.

** Includes (13,793) MWH relating to unbilled revenues.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

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 customers, average KWh per customer, and average revenue per KWh, excluding data 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 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)	Avg. No. of Customers (d)	KWh of Sales per Customer (e)	Revenue per KWh Sold (f)
1	440 Residential Sales					
2	RESIDENTIAL SERVICE	1,117,739	149,084,321	103,281	10,822	0.1334
3	RESIDENTIAL SERVICE TOD	82,793	9,994,235	4,824	17,163	0.1207
4	RESIDENTIAL OFF PEAK ENERGY	14,055	1,503,348	596	23,582	0.1070
5	RESIDENTIAL SVC OPT SENIOR	8,479	1,055,385	1,478	5,737	0.1245
6	OUTDOOR LIGHTING	3,681	750,972			0.2040
7	UNBILLED	(5,797)	(239,650)			0.0413
8	UNRECOVERED FUEL		(8,370,866)			
9	Total Residential Sales	1,220,950	153,777,745	110,179	11,082	0.1259
10						
11	442 Commercial Sales					
12	SMALL GENERAL SERVICE	44,642	7,357,766	6,740	6,623	0.1648
13	SMALL GENERAL SERVICE TOD	477	75,604	53	9,000	0.1585
14	MEDIUM GENERAL SERVICE	450,273	56,892,461	9,836	45,778	0.1264
15	MEDIUM GENERAL SERVICE TOD	12,893	1,498,302	227	56,797	0.1162
16	LARGE GENERAL SERVICE	127,826	12,573,689	87	1,469,264	0.0984
17	LARGE POWER	110,590	9,332,705	5	22,118,000	0.0844
18	ELECTRIC HEATING GENERAL	1,093	125,809	14	78,071	0.1151
19	ELECTRIC HEATING SCHOOLS	5,565	546,468	15	371,000	0.0982
20	MUNICIPAL & SCHOOL SERVICE	24,677	2,698,162	168	146,887	0.1093
21	IRRIGATION SERVICE	7,776	1,145,789	579	13,430	0.1473
22	WATER & SEWAGE SERVICE	25,402	2,416,087	243	104,535	0.0951
23	STREETLIGHTING SERVICE	17	2,057	2	8,500	0.1210
24	OUTDOOR LIGHTING	6,053	1,054,201			0.1742
25	ESTIMATED	1,906	158,527			0.0832
26	UNBILLED	(5,093)	(469,105)			0.0921
27	UNRECOVERED FUEL		(5,775,035)			
28	Total Commercial Sales	814,097	89,633,487	17,969	45,306	0.1101
29						
30						
31						
32						
33						
34						
35						
36						

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

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 customers, average KWh per customer, and average revenue per KWh, excluding data 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 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)	Avg. No. of Customers (d)	KWh of Sales per Customer (e)	Revenue per KWh Sold (f)
1	442 Industrial Sales					
2	SMALL GENERAL SERVICE	1,633	253,581	194	8,418	0.1553
3	MEDIUM GENERAL SERVICE	178,406	21,741,270	664	268,684	0.1219
4	MEDIUM GENERAL SERVICE TOD	113	13,600	4	28,250	0.1204
5	LARGE GENERAL SERVICE	48,385	4,887,620	13	3,721,923	0.1010
6	LARGE POWER	587,989	51,767,228	45	13,066,422	0.0880
7	ELECTRIC HEATING GENERAL	161	18,434	1	161,000	0.1145
8	OUTDOOR LIGHTING	816	132,564			0.1625
9	UNBILLED	(2,895)	(220,122)			0.0760
10	ESTIMATED	(709)	(83,811)			0.1182
11	UNRECOVERED FUEL		(5,618,261)			
12	Total Industrial Sales	813,899	72,892,103	921	883,712	0.0896
13						
14	444 Public Street & Highway Light					
15	SMALL GENERAL SERVICE	201	52,936	86	2,337	0.2634
16	MEDIUM GENERAL SERVICE	218	44,669	83	2,627	0.2049
17	SL CUST OWNED SYS	523	36,293	7	74,714	0.0694
18	SL CUST OWNED SYS METERED	328	29,481	30	10,933	0.0899
19	MUNICIPAL & SCHOOL	56	7,798	2	28,000	0.1393
20	ENERGY CONSERV LIGHTING	5,155	636,673	94	54,840	0.1235
21	STREETLIGHTING SERVICE	3,985	457,155	47	84,787	0.1147
22	OUTDOOR LIGHTING	106	18,467			0.1742
23	UNBILLED	(8)	(1,763)			0.2204
24	UNRECOVERED FUEL		(67,360)			
25	Total Public Street & Highway Light	10,564	1,214,349	349	30,269	0.1150
26						
27	Fuel Clause (see footnote)					
28						
29						
30						
31						
32						
33						
34						
35	Total Billed	2,873,303	318,448,324	129,418	22,202	0.1108
36	Total Unbilled Rev. (See Instr. 6)	(13,793)	(930,640)			0.0675
37	**TOTAL**	**2,859,510**	**317,517,684**	**129,418**	**22,202**	0.1110

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2018

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)	
305.0	27	a	440 Residential Sales	
			RESIDENTIAL SERVICE	8,988,337
			RESIDENTIAL SERVICE TOD	735,794
			OUTDOOR LIGHTING	28,333
			RESIDENTIAL OFF PEAK ENERGY STORAGE	135,865
			RESIDENTIAL SVC OPT SENIOR CITIZEN	64,016
			RESIDENTIAL TOTAL	9,952,345
			442 Commercial Sales	
			SMALL GENERAL SERVICE	620,330
			SMALL GENERAL SERVICE TOD	4,053
			MEDIUM GENERAL SERVICE	3,222,899
			MEDIUM GENERAL SERVICE TOD	95,875
			LARGE GENERAL SERVICE	891,324
			LARGE POWER	781,173
			ELECTRIC HEATING GENERAL	19,640
			ELECTRIC HEATING SCHOOLS	54,849
			MUNICIPAL & SCHOOL SERVICE	196,310
			IRRIGATION SERVICE	31,397
			WATER & SEWAGE SERVICE	212,451
			OUTDOOR AND STREET LIGHTING	45,972
			COMMERCIAL TOTAL	6,176,273
			442 Industrial Sales	
			SMALL GENERAL SERVICE	23,374
			MEDIUM GENERAL SERVICE	1,402,533
			MEDIUM GENERAL SERVICE TOD	828
			LARGE GENERAL SERVICE	350,471
			LARGE POWER	4,196,386
			ELECTRIC HEATING GENERAL	2,898
			OUTDOOR AND STREET LIGHTING	6,281
			INDUSTRIAL TOTAL	5,982,771
			444 Public Street & Highway Light	
			SMALL GENERAL SERVICE	2,755
			MEDIUM GENERAL SERVICE	512
			SL CUST OWNED SYS	3,694
			SL CUST OWNED SYS METERED	2,810
			MUNICIPAL & SCHOOL SERVICE	500
			OUTDOOR AND STREET LIGHTING	28,906
			ENERGY CONSERVE LIGHTING	36,313
			PUBLIC STREET & HIGHWAY LIGHT TOTAL	75,490
			GRAND TOTAL	**22,186,879**

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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 2018/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)	Actual Demand (MW): 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	TOWN OF AVILA	RQ	Note 1			
11	TOWN OF NEW CARLISLE	RQ	Note 1			
12	TOWN OF WARREN	RQ	Note 1			
13	VILLAGE OF PAW PAW	RQ	Note 1			
14	WABASH VALLEY POWER ASSN INC.	RQ	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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.
452,866	22,087,867	12,334,660		34,422,527	1
288,842	13,175,071	7,839,855		21,014,926	2
67,101	3,569,126	1,874,599		5,443,725	3
91,879	4,852,571	2,609,312		7,461,883	4
618,874	30,785,232	18,313,894		49,099,126	5
128,382	6,502,654	3,666,555		10,169,209	6
151,647	7,092,926	4,337,166		11,430,092	7
220,771	11,238,197	6,450,544		17,688,741	8
1,645,836	63,353,816	39,576,478		102,930,294	9
38,753	1,973,478	1,080,393		3,053,871	10
11,237	590,954	396,956		987,910	11
19,187	1,017,143	583,066		1,600,209	12
44,965	2,337,979	1,457,234		3,795,213	13
827,141	39,335,177	21,759,218		61,094,395	14
4,607,481	210,658,492	122,279,930	-42,118,026	290,820,396	
7,007,305	-1,615,003	197,606,361	0	195,991,358	
11,614,786	**209,043,489**	**319,886,291**	**-42,118,026**	**486,811,754**	

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)	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	WOLVERINE POWER SUPPLY COOP	RQ	Note 1			
2	PJM TRANSMISSION FOR RQ	RQ	Various			
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	COMMONWEALTH EDISON COMPANY	OS	Note 1			
8	DP&L POWER SERVICES	OS	Note 1			
9	DUKE ENERGY OHIO, INC	OS	Note 1			
10	DUQUESNE LIGHT COMPANY	OS	Note 1			
11	EVOLUTION MARKETS FUTURES, LLC	OS	Note 1			
12	FIRSTENERGY TRADING SERVICES	OS	Note 1			
13	ICAP ENERGY LLC	OS	Note 1			
14	ICE TRADE VAULT LLC	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 2018/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.
	2,746,301			2,746,301	1
			-42,118,026	-42,118,026	2
4,992		173,977		173,977	3
		-1,085		-1,085	4
		-30,781		-30,781	5
		-6,347		-6,347	6
105,366		3,508,506		3,508,506	7
52,292		2,669,904		2,669,904	8
122,966		6,096,411		6,096,411	9
332,930		17,202,293		17,202,293	10
		-22,096		-22,096	11
126,893		6,385,700		6,385,700	12
		-41,144		-41,144	13
		-32,379		-32,379	14
4,607,481	210,658,492	122,279,930	-42,118,026	290,820,396	
7,007,305	-1,615,003	197,606,361	0	195,991,358	
11,614,786	**209,043,489**	**319,886,291**	**-42,118,026**	**486,811,754**	

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 2018/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:
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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	IVG ENERGY, LTD	OS	Note 1			
2	MIDWEST ISO	OS	Note 1			
3	MIZUHO SECURITIES USA INC	OS	Note 1			
4	OHIO POWER COMPANY (AUCTION)	OS	Note 1			
5	OVER/UNDER CAPACITY TRACKER	OS	Note 1			
6	OVER/UNDER PJM TRACKER	OS	Note 1			
7	PJM INTERCONNECTION	OS	Note 1			
8	PPL ELECTRIC UTILITIES CORP	OS	Note 1			
9	RBC CAPITAL MARKET, LLC	OS	Note 1			
10	SPSR2 - MAREX SPECTRON	OS	Note 1			
11	TFS ENERGY FUTURES, LLC	OS	Note 1			
12	TRIDENT BROKERAGE SERVICES, LLC	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
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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.
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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.
		-54,257		-54,257	1
		-15		-15	2
		929,505		929,505	3
141,082		7,062,283		7,062,283	4
	-1,927,734			-1,927,734	5
		-8,098,173		-8,098,173	6
6,084,068	312,731	175,549,106		175,861,837	7
28,489		1,388,884		1,388,884	8
		-15,142,781		-15,142,781	9
		-909		-909	10
		-7,934		-7,934	11
		-3,413		-3,413	12
		-43,314		-43,314	13
-3,517		-102,628		-102,628	14
4,607,481	210,658,492	122,279,930	-42,118,026	290,820,396	
7,007,305	-1,615,003	197,606,361	0	195,991,358	
11,614,786	**209,043,489**	**319,886,291**	**-42,118,026**	**486,811,754**	

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).
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	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	UGI UTILITIES	OS	Note 1			
2	WABASH VALLEY POWER ASSN INC.	OS	Note 1			
3	WELLS FARGO SECURITIES, LLC	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.
11,744		516,033		516,033	1
		-237,591		-237,591	2
		-51,394		-51,394	3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
4,607,481	210,658,492	122,279,930	-42,118,026	290,820,396	
7,007,305	-1,615,003	197,606,361	0	195,991,358	
11,614,786	**209,043,489**	**319,886,291**	**-42,118,026**	**486,811,754**	

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: 310.1 Line No.: 2 Column: j

PJM transmission expenses related to wholesale customers.

Schedule Page: 310.2 Line No.: 4 Column: a

An affiliated company.

Schedule Page: 310.2 Line No.: 4 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: 310.2 Line No.: 5 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: 310.2 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.

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amt. For Current Year (b)	Amt. For Previous Year (c)
1	**1. POWER PRODUCTION EXPENSES**		
2	**A. Steam Power Generation**		
3	Operation		
4	(500) Operation Supervision and Engineering	5,116,368	4,116,795
5	(501) Fuel	149,279,658	137,375,658
6	(502) Steam Expenses	17,224,726	15,350,914
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred - **CR**.		
9	(505) Electric Expenses	1,694,828	1,873,898
10	(506) Miscellaneous Steam Power Expenses	4,580,033	3,268,991
11	(507) Rents	70,170,734	70,159,078
12	Allowances	1,224,320	1,038,606
13	TOTAL Operation *(Enter Total of Lines 4 thru 12)*	249,290,667	233,183,940
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,689,971	2,286,011
16	(511) Maintenance of Structures	1,316,489	1,358,884
17	(512) Maintenance of Boiler Plant	11,914,323	8,411,145
18	(513) Maintenance of Electric Plant	4,233,322	2,594,303
19	(514) Maintenance of Miscellaneous Steam Plant	1,134,369	1,149,705
20	TOTAL Maintenance *(Enter Total of Lines 15 thru 19)*	21,288,474	15,800,048
21	TOTAL Power Production Expenses-Steam Power (*Total of lines 13 & 20*)	270,579,141	248,983,988
22	**B. Nuclear Power Generation**		
23	Operation		
24	(517) Operation Supervision and Engineering	22,132,027	17,374,231
25	(518) Fuel	117,690,451	132,994,595
26	(519) Coolants and Water	7,331,878	8,370,744
27	(520) Steam Expenses	14,183,623	15,684,414
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred - **CR**		
30	(523) Electric Expenses	4,724,834	4,361,456
31	(524) Miscellaneous Nuclear Power Expenses	73,331,732	67,639,472
32	(525) Rents		
33	TOTAL Operation *(Enter Total of lines 24 thru 32)*	239,394,545	246,424,912
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	10,362,195	11,072,533
36	(529) Maintenance of Structures	4,733,634	3,758,221
37	(530) Maintenance of Reactor Plant Equipment	81,885,406	76,952,653
38	(531) Maintenance of Electric Plant	19,213,918	19,227,738
39	(532) Maintenance of Miscellaneous Nuclear Plant	19,377,398	19,707,637
40	TOTAL Maintenance *(Enter Total of Lines 35 thru 39)*	135,572,551	130,718,782
41	TOTAL Power Production Expenses-Nuclear Power *(Total of lines 33 & 40)*	374,967,096	377,143,694
42	**C. Hydraulic Power Generation**		
43	Operation		
44	(535) Operation Supervision and Engineering	565,043	473,685
45	(536) Water for Power	29,109	
46	(537) Hydraulic Expenses	91,006	117,119
47	(538) Electric Expenses	9,868	1,319
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,345,681	1,182,397
49	(540) Rents		
50	TOTAL Operation *(Enter Total of Lines 44 thru 49)*	2,040,707	1,774,520

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (cont'd)

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

Line No.	Account (a)	Amt. For Current Year (b)	Amt. For Previous Year (c)
51	**C. Hydraulic Power Generation (Continued)**		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	142,877	187,530
54	(542) Maintenance of Structures	1,519,255	787,318
55	(543) Maintenance of Reservoirs, Dams, and Waterways	512,963	871,492
56	(544) Maintenance of Electric Plant	621,777	407,255
57	(545) Maintenance of Miscellaneous Hydraulic Plant	180,192	105,568
58	TOTAL Maintenance *(Total of Lines 53 thru 57)*	2,977,064	2,359,163
59	TOTAL Pwr. Production Expenses-Hydraulic Pwr.*(Total of lines 50 & 58)*	5,017,771	4,133,683
60	**D. Other Power Generation**		
61	Operation		
62	(546) Operation Supervision and Engineering	95,302	21,314
63	(547) Fuel		
64	(548) Generation Expenses	0	6
65	(549) Miscellaneous Other Power Generation Expenses	414,651	483,704
66	(550) Rents		
67	TOTAL Operation *(Total of Lines 62 thru 66)*	509,953	505,024
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant	5	(232)
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance *(Total of Lines 69 thru 72)*	5	(232)
74	TOTAL Power Production Expenses-Other Power *(Total of Lines 67 & 73)*	509,958	504,792
75	**E. Other Power Supply Expenses**		
76	(555) Purchased Power	486,466,043	394,347,396
77	(556) System Control and Load Dispatching	2,294,161	2,114,994
78	(557) Other Expenses	4,133,685	3,970,176
79	Total Other Power Supply Expenses *(Total of Lines 76 thru 78)*	492,893,889	400,432,566
80	Total Pwr. Production Expenses *(Total of lines 21, 41, 59, 74 & 79)*	1,143,967,855	1,031,198,723
81	**2. TRANSMISSION EXPENSES**		
82	Operation		
83	(560) Operation Supervision and Engineering	6,780,163	4,818,719
84	(561) Load Dispatching	7,073,510	6,506,185
85	(562) Station Expenses	467,483	473,729
86	(563) Overhead Lines Expenses	336,712	268,878
87	(564) Underground Lines Expenses	3,666	
88	(565) Transmission of Electricity by Others	86,265,470	117,445,782
89	(566) Miscellaneous Transmission Expenses	3,332,277	1,766,992
90	(567) Rents	48,111	46,466
91	TOTAL Operation *(Total of Lines 83 thru 90)*	104,307,392	131,326,751
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	78,193	82,744
94	(569) Maintenance of Structures	545,234	618,078
95	(570) Maintenance of Station Equipment	2,471,069	1,963,607
96	(571) Maintenance of Overhead Lines	12,717,507	6,776,955
97	(572) Maintenance of Underground Lines	6,576	2,417
98	(573) Maintenance of Miscellaneous Transmission Plant	97,324	109,862
99	TOTAL Maintenance *(Total of Lines 93 thru 98)*	15,915,903	9,553,663
100	TOTAL Transmission Expenses (Total of Lines 91 & 99)	120,223,295	140,880,414
101	**3. REGIONAL MARKET EXPENSES**		
102	Operation		
103	(575) Market Facilitation, Monitoring and Compliance Services	4,958,232	4,948,588

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (cont'd)

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

Line No.	Account (a)	Amt. For Current Year (b)	Amt. For Previous Year (c)
104	**3. DISTRIBUTION EXPENSES**		
105	(580) Operation and Supervison	3,226,046	3,727,629
106	(581) Load Dispatching	687,960	982,245
107	(582) Station Expenses	944,279	678,365
108	(583) Overhead Line Expenses	1,764,253	1,022,924
109	(584) Underground Line Expenses	2,188,818	1,769,488
110	(585) Street Lighting and Signal System Expenses	100,174	109,862
111	(586) Meter Expenses	2,643,288	2,484,258
112	(587) Customer Installations Expenses	339,010	392,812
113	(588) Miscellaneous Expenses	16,373,928	13,323,599
114	(589) Rents	1,720,638	1,669,824
115	TOTAL Operation *(Total of Lines 103 thru 113)*	29,988,394	26,161,006
116	Maintenance		
117	(590) Maintenance Supervision and Engineering	64,989	83,251
118	(591) Maintenance of Structures	31,302	42,016
119	(592) Maintenance of Station Equipment	1,711,168	1,424,578
120	(593) Maintenance of Overhead Lines	45,559,892	35,829,313
121	(594) Maintenance of Underground Lines	2,993,361	2,557,349
122	(595) Maintenance of Line Transformers	123,990	136,349
123	(596) Maintenance of Street Lighting and Signal Systems	325,954	318,338
124	(597) Maintenance of Meters	316,408	232,095
125	(598) Maintenance of Miscellaneous Distribution Plant	285,071	455,116
126	TOTAL Maintenance *(Total of Lines 116 thru 124)*	51,412,135	41,078,405
127	TOTAL Distribution Expenses *(Total of Lines 114 & 125)*	81,400,529	67,239,411
128	**4. CUSTOMER ACCOUNTS EXPENSES**		
129	Operation		
130	(901) Supervision	1,217,999	1,132,839
131	(902) Meter Reading Expenses	995,053	867,290
132	(903) Customer Records and Collection Expenses	13,394,003	12,792,694
133	(904) Uncollectible Accounts	55,988	165,772
134	(905) Miscellaneous Customer Accounts Expenses	61,800	65,601
135	TOTAL Customer Accounts Expenses *(Total of Lines 129 thru 133)*	15,724,843	15,024,196
136	**5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES**		
137	Operation		
138	(907) Supervision	1,028,225	931,246
139	(908) Customer Assistance Expenses	26,445,511	24,313,371
140	(909) Informational and Instructional Expenses	417	
141	(910) Miscellaneous Customer Service and Informational Expenses	14,163	139,435
142	TOTAL Customer Service and Informational Exp. *(Total of Lines 137 thru 140)*	27,488,316	25,384,052
143	**6. SALES EXPENSE**		
144	Operation		
145	(911) Supervision	10	1,290
146	(912) Demonstrating and Selling Expenses	215,292	208,524
147	(913) Advertising Expenses	0	1,354
148	(916) Miscellaneous Sales Expenses		
149	Total Sales Expenses *(Total of Lines 144 thru 147)*	215,302	211,168
150	**7. ADMINISTRATIVE AND GENERAL EXPENSES**		
151	Operation		
152	(920) Administrative and General Salaries	36,307,294	33,826,147
153	(921) Office Supplies and Expenses	3,457,617	3,198,866
154	(Less) (922) Administrative Expenses Transferred - **CR**	4,721,008	3,482,860

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (cont'd)

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

Line No.	Account (a)	Amt. For Current Year (b)	Amt. For Previous Year (c)
154	**7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)**		
155	(923) Outside Services Employed	9,226,502	7,626,203
156	(924) Property Insurance	(4,010,867)	4,235,382
157	(925) Injuries and Damages	7,665,705	6,334,185
158	(926) Employee Pensions and Benefits	16,246,868	26,450,155
159	(927) Franchise Requirements		
160	(928) Regulatory Commission Expenses	13,239,872	13,763,059
161	(929) Duplicate Charges - **CR**.	793,220	946,508
162	(930.1) General Advertising Expenses	307,016	480,267
163	(930.2) Miscellaneous General Expenses	4,620,958	4,505,198
164	(931) Rents	2,675,384	2,754,974
165	TOTAL Operation (*Total of Lines 151 thru 164)*	84,222,121	98,745,068
166	Maintenance		
167	(935) Maintenance of General Plant	10,921,382	8,885,926
168	TOTAL Administrative and General Expenses *(Total of Lines 165 & 167)*	95,143,503	107,630,994
169	TOTAL Electric Operation and Maintenance Expenses *(Enter total*	1,489,121,875	1,392,517,546
	of lines 80, 100, 126, 134, 141, 148, and 168)		

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.

2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.

3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1. Payroll Period Ended (Date)	12/31/2018	12/31/2017
2. Total Regular Full-Time Employees	2,385	2,404
3. Total Part-Time and Temporary Employees	9	11
4. Total Employees	2,394	2,415

Name of Respondent Indiana Michigan Power Company		Date of Report (Mo, Da, Yr)	Year of Report 12/31/18

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)
320	5	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.
320	25	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.
320	31	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 Indian Utility Regulatory Commission.
320	85	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 and 353 multiplied by the balance in O&M accounts 562, 569,and 570.
320	94	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.
320	156	b	The insurance expenses for generation included in I&M's generation formula rate are identified by a query from the general ledger.

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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)	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	OVEC POWER SCHEDULING	OS				
10	OVER/UNDER PJM EXP TRACKER	OS				
11	OVER/UNDER RESOURCE ADEQUACY	OS				
12	PJM INTERCONNECTION	OS				
13	RANDOLPH SCHOOLS	OS				
14	WILDCAT WIND FARM	OS				
	Total					

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)	
4,162,940			133,411,432	104,496,745		237,908,177	1
				144,774		144,774	2
118,832				10,832,568		10,832,568	3
209,512				14,226,557		14,226,557	4
1,190				32,210		32,210	5
1				31		31	6
650,380				28,695,579		28,695,579	7
				11,875		11,875	8
959,125			26,555,612	23,684,683		50,240,295	9
				28,782,903		28,782,903	10
			1,318,208			1,318,208	11
1,846,868				95,625,043		95,625,043	12
				16,741		16,741	13
309,127				18,631,027		18,631,027	14
8,257,977			161,285,252	325,180,791		486,466,043	

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 2018/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	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		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)	
2				55		55	1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
8,257,977			161,285,252	325,180,791		486,466,043	

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

Affiliated Company.

Schedule Page: 326 Line No.: 10 Column: a

Per the IURC's Order in Cause No. 44967, 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.

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

Over-/Under-recovery accounting to track incremental changes in the Company's purchased power costs, per the IURC's Order in Cause No. 44967.

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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 2018/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	FNO
6	PJM Network Integ Rev - Affil	Various	Various	FNO
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				
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 2018/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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
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
						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	

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.
5,054,571			5,054,571	1
14,157,136			14,157,136	2
3,096,784			3,096,784	3
154,104			154,104	4
-3,136			-3,136	5
8,754,951			8,754,951	6
1,449,386			1,449,386	7
	205,592		205,592	8
	62,921		62,921	9
		108,664	108,664	10
		512,182	512,182	11
128,394			128,394	12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
32,792,190	**268,513**	**620,846**	**33,681,549**	

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

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

SALES TO RAILROADS AND RAILWAYS AND INTERDEPARTMENTAL SALES (Accounts 446, 448)

1. Report particulars concerning sales included in Accounts 446 and 448.
2. For Sales to Railroads and Railways, Account 446, give name of railroad or railway in addition to other required information. If contract covers several points of delivery and small amounts of electricity are delivered at each point, such sales may be grouped.
3. For Interdepartmental Sales, Account 448, give name of other department and basis of charge to other department in addition to other required information.
4. Designate associated companies.
5. Provide subheading and total for each account.

Line No.	Item (a)	Point of Delivery (b)	Kilowatt-hours (c)	Revenue (d)	Revenue per kwh (in cents) (e)
1	None				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					

RENT FROM ELECTRICITY PROPERTY AND INTERDEPARTMENTAL RENTS (Accounts 454, 455)

1. Report particulars concerning rents received included in Accounts 454 and 455.
2. Minor rents may be grouped by classes.
3. If rents are included which were arrived at under an arrangement for apportioning expenses of a joint facility, whereby the amount included in this account represents profit or return on property, depreciation and taxes, give particulars and the basis of apportionment of such charges to Accounts 454 and 455.
4. Designate is lessee is an associated company.
5. Provide a subheading and total for each account.

Line No.	Name of Lessee or Department (a)	Description of Property (b)	Amount of Revenue for Year (c)
16	Account 454 - Rents from Electric Property - Michigan		
17	Miscellaneous Lessees	Pole Contact Rental	963,963
18	American Electric Power Service Corporation**	Benton Harbor Service Center	9,695
19	Miscellaneous Lessees	Agriculture, Commercial, Residential	104,488
20			
21	Total Account 454		1,078,146
22			
23			
24	Account 455		
25	None		
26			
27	**Affiliated Entity		
28			
29			

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A resubmission	(Mo, Da, Yr)	12/31/18

SALES OF WATER AND WATER POWER (Account 453)

1. Report below the information called for concerning revenues derived during the year from sales to others of water or water power.
2. In column (c) show the name of the power development of the respondent supplying the water or waer power sold.
3. Designate associated companies.

Line No.	Name of Purchaser (a)	Purpose for Which Water Was Used (b)	Power Plant Development Supplying Water or Water Power (c)	Amount of Revenue for Year (e)
1	None			
2				
3				
4				
5				
6				
7				
8				
9				
10	TOTAL			

MISCELLANEOUS SERVICE REVENUES AND OTHER ELECTRIC REVENUES (Accounts 451, 456)

1. Report particulars concerning miscellaneous service revenues and other electric revenues derived from electric utility operations during year. Report separately in this schedule the total revenues from operation of fish and wildlife and recreation facilities, regardless of whether such facilities are operated by company or by contract concessionaires. Provide a subheading and total for each account. For Account 456, list first revenues realized through Research and Development ventures, see Account 456.
2. Designate associated companies.
3. Minor items may be grouped by classes.

Line No.	Name of Company and Description of Service (a)	Amount of Revenue for Year (b)
11	Account 451 - Miscellaneous Service Revenues - Michigan	
12	Other	763,830
13		
14	Account 456 - Other Electric Revenues - Michigan	
15		
16	Associated Business Development	15,989
17	PJM/RTO Cost Recovery Items	4,869,762
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30	TOTAL	5,649,581

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 2018/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)	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					12,517,210	12,517,210
2	PJM NITS	OS					73,079,733	73,079,733
3	PJM-Trans Owner	OS					668,527	668,527
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						86,265,470	86,265,470

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

Transmission Enhancement Charges and Credits (PJM OATT Schedule 12)

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

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

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

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

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 4/12/2018	Year of Report 12/31/2018

LEASE RENTALS CHARGED

1. For purposes of this schedule a "lease" is defined as a contract or other agreement by which one party (lessor conveys an intangible right or land or other tangible property and equipment to another lessee) for a specified period of one year or more for rent.

2. Report below, for leases with annual charges of $25,000 or more, but less than $250,000, the data called for in columns a, b (description only), f, g, and j.

3. For leases having annual charges of $250,000 or more, report the data called for in all the columns below.

4. The annual charges referred to in instruction 1 and 2 include the basic lease payment and other payments to or in behalf of the lessor such as taxes, depreciation, assumed interest or dividends on the lesser Securities, cost of property replacements ** and other expenditures with respect to leased property except the expenses paid by lessee are to be itemized in column f below.

5. Leases of construction equipment in connection with construction work in progress are not required to be reported herein. Continuous, master or open-end leases fof EDP or office equipment, automobile fleets and other equipment that is short-lived and replaced under terms of the lease or for pole rentals shall report only the data called for in columns a, b (description only), f, g and j. unless the lessee has the option to purchase the property.

6. In column a report the name of the

A. LEASE RENTAL CHARGED TO ELECTRIC OPERATING EXPENSES

Name of Lessor (a)	Basic Details of Lease (b)	Terminal Dates of Lease, Primary (P) or Rental (R) (c)
Wells Fargo Equipment Finance (Formerly GE Capital Commercial Inc)	Office Furniture and Equipment and Transportation Equipment (2) (Leases 4425,4426,4427)	
Huntington Bank	Office Furniture and Equipment and Transportation Equipment (2) (Leases 4196, 4228, 4565)	
Citizens Asset Finance (Formerly RBS Asset Finance)	Office Furniture and Equipment and Transportation Equipment (2) (Leases 4200, 4224, 4320)	
Banc of America Leasing	Office Furniture and Equipment and Transportation Equipment (2) (Leases 4773, 4774)	

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 4/12/2018	Year of Report 12/31/2018

LEASE RENTALS CHARGED (Continued)

lessor. List lessors that are associated companies * (describing association) first, followed by non-associated lessors. * See definition on page 226 (B)

7. In column (b) for each leasing arrangement, report in order, classified by generating station, transmission line, distribution system, large substation, or other operating unit or system, followed by any other leasing arrangements not covered under the preceding classifications: Description of the property, whether the lease is a sale and leaseback, whether leasee has option to purchase and conditions of purchase, whether lease is cancellable by either party and the cancellation conditions, state the tax treatment used and the accounting treatment of the lease payments (levelized charges to expense or other treatment), the basis of any charges apportioned between the lessor and lessee, and the responsibility of the respondent for operation and maintenance expences and replacement of property.

The above information is to be reported with initiation of the lease and thereafter when changed or every five years, which ever occurs first.

8. Report in column (d), as of the date of the current lease term, the original cost of the property leased, estimate if not known, or the fair market value of the property if greater than the original cost and indicate as shown. If the leased property is part of a large unit, such as part of a building, indicate without associating any cost or value with it.

9. Report in column (k) below the estimated remaining annual charges under the current term of the lease. Do not apply a present value to the estimate. Assume that cancellable leases will not be cancelled when estimating the remaining charges.

A. LEASE RENTAL CHARGED TO ELECTRIC OPERATING EXPENSES (Continued)

Orginal Cost (O) or Fair Market Value (D) of Property	Expense to be Paid By Lessee Itemize	Amount of Rent - Current Term				Account Charged	Remaining Annual Charges Under Lease Est. If Not Known
		Current Year		Accumulated To Date			
		Lessor	Other	Lessor	Other		
(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		-				506	
		12,870				588	
		-				931	
		89,232				501	
		19,357				506	
		-				514	
		994,763				524	
		13,606				539	
		8,522				566	
		9,092				580	
		224,223				588	
		349,519				931	
		5,302				935	
		181,596				501	
		84,281				524	
		105,725				931	
		2,484				506	
		11,437				524	
		3,700				588	
		34,736				931	

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 4/12/2018	Year of Report 12/31/2018

A. LEASE RENTAL CHARGED TO ELECTRIC OPERATING EXPENSES (Continued)

Name of Lessor (a)	Basic Details of Lease (b)	Terminal Dates of Lease, Primary (P) or Rental (R) (c)
Blue Jay Associates	Fort Wayne General Service Center BLDG225 (1) LPM1853 Date of Lease: 5-1-71 1. This is a sale and leaseback 2. Lessee has option to purchase under varying conditions depending on the status of the premises 3. Lease may be cancelled by either party in event of change of status of the premises 4. Respondent is responsible for all operation and maintenance expenses.	04/30/2021
SS Properties Associates	Muncie Service Building BLDG218 LPM1863 (1) Date of Lease: 5-26-72 1. This is a sale and leaseback 2. Lessee has option to purchase under varying conditions depending on the status of the premises 3. Lease may be cancelled by either party in event of change of status of the premises 4. Respondent is responsible for all operation and maintenance expenses.	12/31/2017

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 4/12/2018	Year of Report 12/31/2018

A. LEASE RENTAL CHARGED TO ELECTRIC OPERATING EXPENSES (Continued)

Orginal Cost (O) or Fair Market Value (D) of Property (d)	Expense to be Paid By Lessee Itemize (e)	Amount of Rent - Current Term: Current Year: Lessor (f)	Current Year: Other (g)	Accumulated To Date: Lessor (h)	Accumulated To Date: Other (i)	Account Charged (j)	Remaining Annual Charges Under Lease Est. If Not Known (k)
	Real Estate taxes, assessments, maintenance, alterations, replacements and additions, insurance, and utilities.	86,352				931	
	Real Estate taxes, assessments, maintenance, alterations, replacements and additions, insurance, and utilities.	73,750				931	

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 4/12/2018	Year of Report 12/31/2018

A. LEASE RENTAL CHARGED TO ELECTRIC OPERATING EXPENSES (Continued)

Name of Lessor (a)	Basic Details of Lease (b)	Terminal Dates of Lease, Primary (P) or Rental (R) (c)
Slater Associates	South Bend Service Building BLDG235 Ls# 558 (1) LPM2389 Date of Lease: 10-1-79 1. This is a sale and leaseback 2. Lessee has option to purchase under varying conditions depending on the status of the premises 3. Lease may be cancelled by either party in event of change of status of the premises 4. Respondent is responsible for all operation and maintenance expenses.	12/31/2024
One Summit II LLC	Indiana Michigan Power Center - BLDG227 - LPM10722 Replaced LPM2688 - effective 10/1/2014	10/31/2031
West Ohio II, LLC	State President Office - Indiana, LPM2448 Date of Lease: 1/17/2000 1. This is not a sale and leaseback 2. Lease does not have an option to purchase 3. Lease may be cancelled under certain conditions	02/28/2019
U.S. Bank Trust N.A. (Formerly First Chicago Leasing Corp)	Rockport Generating Plant Unit 2 Date of Lease: 12/7/89 1. This is a sale and leaseback 2. No purchase option 3. Lease may be cancelled under certain conditions 4. Respondent is responsible for all operation and maintenance expenses.	12/07/22 (P)

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 4/12/2018	Year of Report 12/31/2018

A. LEASE RENTAL CHARGED TO ELECTRIC OPERATING EXPENSES (Continued)

Orginal Cost (O) or Fair Market Value (D) of Property	Expense to be Paid By Lessee Itemize	Amount of Rent - Current Term				Account Charged	Remaining Annual Charges Under Lease Est. If Not Known
		Current Year		Accumulated To Date			
		Lessor	Other	Lessor	Other		
(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
5,225,000	Real Estate taxes,	0		0		184	
	assessments, maintenance,	81,655		351,884		408	
	alterations, replacements	0		0		567	
	and additions, insurance,	523,876		1,949,141		588	
	and utilities.	0		0		589	
		0		0		921	
		2,012		17,490		924	
		480,000		1,920,000		931	2,880,000
11,000,000	Real Estate taxes,						
	assessments, maintenance,	0		134,840		408	
	alterations, replacements	453,016		1,451,465		588	
	and additions, insurance,	2,306		64,693		924	
	and utilities.	1,072,050		10,931,762		931	13,757,975
	Maintenance,						
	alterations, replacements,						
	additions and insurance	61,727				931	
850,000,000	All expenses necessary to						
	operate, maintain,						
	preserve and keep the	73,853,988		2,145,121,522	26,654,952	507	295,415,952
	leased property in good						
	working order. Also						
	responsible for taxes and						
	insurance.						

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A. LEASE RENTAL CHARGED TO ELECTRIC OPERATING EXPENSES (Continued)

Name of Lessor (a)	Basic Details of Lease (b)	Terminal Dates of Lease, Primary (P) or Rental (R) (c)
Benton Associates	Benton Harbor Service Building BLDG237 LPM1864 (1) Date of Lease: 7-15-72 (formerly St Joe Serv Ctr) 1. This is a sale and leaseback 2. Lessee has option to purchase under varying conditions depending on the status of the premises 3. Lease may be cancelled by either party in event of change of status of the premises 4. Respondent is responsible for all operation and maintenance expenses.	12/31/2022
American Tower, LP	Milan Telecom Site - (9124) - (TRI1000151)	
American Tower, LP	Butler Telecom - (9125) - (TRI1000152)	
Capital Tower LLC	Lansing Office LPM9010	01/31/2019
Hoosier AM FM LLC	TRI1000251	7/31/2021
Midland LLC	TRI1000131	7/31/2020
SBA Structures Inc	TRI1000143	7/31/2021
WSJM Inc	TRI1000474	11/30/2021
WSJM Inc	TRI1000244	12/31/2031
	NOTES: (1) Apportionment based on percentage of floor space occupied. (2) Apportionment based on percentage of equipment usage. (3) Charged directly to operating expense of barging operation. Tax treatment: Treated as lease, rental payments are deducted for federal income tax purposes. Accounting treatment: Leasing rentals distributed to benefiting accounts as incurred based on accrual method.	

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A. LEASE RENTAL CHARGED TO ELECTRIC OPERATING EXPENSES (Continued)

Orginal Cost (O) or Fair Market Value (D) of Property	Expense to be Paid By Lessee Itemize	Amount of Rent - Current Term				Account Charged	Remaining Annual Charges Under Lease Est. If Not Known
		Current Year		Accumulated To Date			
		Lessor	Other	Lessor	Other		
(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
						408	
						588	
						924	
		90,000				931	
		46,750				935	
		53,354				935	
		0				588	
		0				924	
		33,441				931	
		26,246				935	
		16,529				935	
		37,949				935	
		19,776				935	
		26,611				935	
	Total Section A	79,191,831					

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B. OTHER LEASE RENTALS CHARGED (Such as to Deferred Debits, etc.)

Name of Lessor (a)	Basic Details of Lease (b)	Terminal Dates of Lease, Primary (P) or Rental (R) (c)
Wells Fargo Equipment Finance (Formerly GE Capital Commercial Inc)	Office Furniture and Equipment and Transportation Equipment (2) (Leases 4425,4426,4427)	
Huntington Bank	Office Furniture and Equipment and Transportation Equipment (2) (Leases 4196, 4228, 4565)	
Citizens Asset Finance (Formerly RBS Operating Co)	Transportation Equipment (Leases 4200, 4224, 4320)	
Banc of America Leasing	Office Furniture and Equipment and Transportation Equipment (2) (Leases 4773, 4774)	
BTMU Capital	Railcar Lease formally with AEP Transportation Wilmington Trust as Security Trustee (Lease 4084)	06/30/2023
Wilmington Trust Co.	Railcars Trust 2004-A (Lease 3616) - Renewal 2016	12/15/2024
Progress Rail formerly US Bank	Railcars Trust 91-3 (Lease 4906) - Renewal of 00735 formerly leases 4461/4462	09/30/2020
Francis G Halstead Trust	Meadow Lake Laydown (LPM10832)	

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B. OTHER LEASE RENTALS CHARGED (Such as to Deferred Debits, etc.) (Continued)

Orginal Cost (O) or Fair Market Value (D) of Property (d)	Expense to be Paid By Lessee Itemize (e)	Amount of Rent - Current Term: Current Year: Lessor (f)	Other (g)	Accumulated To Date: Lessor (h)	Other (i)	Account Charged (j)	Remaining Annual Charges Under Lease Est. If Not Known (k)
		14,636				107	
		-1,331,688				121	
		1,148,133				122	
		161,355				152	
		169,418				184	
		187,986				417	
		376,971				107	
		-5,321				121	
		17,189				122	
		141,129				152	
		0				163	
		7,384				184	
		7,986				417	
		85,498				107	
		-1,145				121	
		1,001				122	
		147,171				152	
		5,999				163	
		2,668,860				184	
		69,840				417	
		15,151				107	
		14,756				121	
		-5,888				122	
		4,563,416				184	
		28,432				417	
		1,290,821				186	28,297,218
		15,409				242	
		54,541				253	
12,271,945		1,796,537				186	19,257,533
		32,416				253	
4,379,951		817,860				186	1,908,818
		162,728				253	
		56,000				107	
		-56,000				165	

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 4/12/2018	Year of Report 12/31/2018

B. OTHER LEASE RENTALS CHARGED (Such as to Deferred Debits, etc.)

Name of Lessor (a)	Basic Details of Lease (b)	Terminal Dates of Lease, Primary (P) or Rental (R) (c)
Citizens Asset Finance	Water Transporation Equipment (Lease 4991)	06/30/2023
Citizens Asset Finance	Water Transporation Equipment (Lease 4992)	12/31/2022
Citizens Asset Finance	Water Transporation Equipment (Lease 5048)	10/31/2025
Fifth Third Bank	Water Transporation Equipment (Lease 4993)	02/28/2021
Manufacturers and Traders Trust Co	Water Transporation Equipment (Lease 4990)	10/31/2019
PNC Equipment Financing	Water Transporation Equipment (Lease 4995)	07/31/2020
RBS Asset Finance Master Owner Trust	Water Transporation Equipment (Lease 4951)	01/31/2021
Regions Equipment Finance Corp	Water Transporation Equipment (Lease 4949)	12/31/2030
Sun Trust Equipment	Water Transporation Equipment (Lease 4950)	12/31/2030
Wells Fargo Equipment Finance	Water Transportation Equipment (Leases 4988, 4989)	03/31/2019
Delta Marine	Water Transportation Equipment	12/31/2016
Consolidation Coal Company	Water Transporation Equipment	08/31/2017

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 4/12/2018	Year of Report 12/31/2018

B. OTHER LEASE RENTALS CHARGED (Such as to Deferred Debits, etc.) (Continued)

Orginal Cost (O) or Fair Market Value (D) of Property	Expense to be Paid By Lessee Itemize	Amount of Rent - Current Term				Account Charged	Remaining Annual Charges Under Lease Est. If Not Known
		Current Year		Accumulated To Date			
		Lessor	Other	Lessor	Other		
(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		293,752				417	
		2,154,118				417	
		1,034,000				417	
		2,080,800				417	
		1,113,285				417	
		1,108,100				417	
		882,643				417	
		1,328,256				417	
		929,234				417	
		946,213				417	
		65,130				417	
		36,000				417	
	Total Section B	24,630,114					

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 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	3,165,519
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	3,565
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	649,580
7	American Electric Power Service Corp Billings	392,233
8	Corporate Money Pool Allocations	71,764
9	Corporate Legal and Financing	85,428
10	Corporate Contributions and Memberships	384,509
11	Intercompany Billings	-142,627
12	Minor Items	10,987
13		
14		
15		
16		
17		
18		
19		
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46	TOTAL	4,620,958

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 2018/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			25,494,246		25,494,246
2	Steam Production Plant	63,859,582	491,593	8,502,842		72,854,017
3	Nuclear Production Plant	85,875,841	1,512,627			87,388,468
4	Hydraulic Production Plant-Conventional	1,280,602	12,559			1,293,161
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	2,581,598				2,581,598
7	Transmission Plant	27,945,744				27,945,744
8	Distribution Plant	69,753,588				69,753,588
9	Regional Transmission and Market Operation					
10	General Plant	4,975,608	1,177	773,757		5,750,542
11	Common Plant-Electric					
12	TOTAL	256,272,563	2,017,956	34,770,845		293,061,364

B. Basis for Amortization Charges

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

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 2018/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	97,719	44.00	9.00	7.29		
14	311 - Rockport U2	4,145	33.00	1.00	3.26		
15	311 - Rkpt DSI U1	2,905	44.00	9.00	8.03		
16	311 - Rkpt DSI U2	503	33.00	1.00	9.61		
17	312 - Rockport ACI	11,822	44.00	9.00	6.69		
18	312 - Rockport U1	406,572	44.00	9.00	8.16		
19	312 - Rockport U2	19,357	33.00	1.00	3.53		
20	312 - Rockport U1 -SCR	133,190	44.00	9.00	8.16		
21	312 - Rkpt DSI U1	51,720	44.00	9.00	8.96		
22	312 - Rkpt DSI U1 -Pre	24,807	44.00	9.00	8.16		
23	312 - Rkpt DSI U2	51,143	33.00	1.00	9.84		
24	314 - Rockport U1	105,969	44.00	9.00	7.81		
25	314 - Rockport U2	867	33.00	1.00	3.72		
26	315 - Rockport U1	58,913	44.00	9.00	7.35		
27	315 - Rockport U2	2,082	33.00	1.00	3.43		
28	316 - Rockport U1	16,440	44.00	9.00	7.75		
29	316 - Rockport U2	6,843	33.00	1.00	3.22		
30	TOTAL STEAM	994,997					
31							
32	NUCLEAR						
33	321 - Cook U1	78,921	59.00	21.00	2.23		
34	321 - Cook U2	349,416	59.00	21.00	2.55		
35	322 - Cook U1	673,773	59.00	19.00	3.24		
36	322 - Cook U2	912,673	59.00	19.00	3.01		
37	323 - Cook U1	271,979	59.00	5.00	4.00		
38	323 - Cook U2	405,191	59.00	5.00	4.11		
39	324 - Cook U1	109,892	59.00	-5.00	2.77		
40	324 - Cook U2	157,552	59.00	-5.00	2.93		
41	325 - Cook U1	34,387	59.00		3.58		
42	325 - Cook U2	223,330	59.00		3.14		
43	TOTAL NUCLEAR	3,217,114					
44							
45	HYDRO						
46	331 - Berrien Springs	587	128.00	4.00	2.41		
47	331 - Buchanan	610	117.00	4.00	2.71		
48	331 - Constantine	344	132.00	26.00	1.80		
49	331 - Crew Service Cen	417		4.00	0.89		
50	331 - Elkhart	1,049	117.00	2.00	3.25		

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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	754	110.00	4.00	1.94		
13	331 - Twin Branch	781	132.00	4.00	1.77		
14	332 - Berrien Springs	5,109	128.00	4.00	1.69		
15	332 - Buchanan	4,695	117.00	4.00	1.50		
16	332 - Constantine	1,228	132.00	26.00	1.80		
17	332 - Elkhart	7,085	117.00	2.00	3.07		
18	332 - Mottville	2,188	110.00	4.00	1.97		
19	332 - Twin Branch	5,097	132.00	4.00	1.66		
20	333 - Berrien Springs	7,176	128.00	4.00	2.23		
21	333 - Buchanan	1,296	117.00	4.00	1.49		
22	333 - Constantine	737	132.00	26.00	1.70		
23	333 - Elkhart	562	117.00	2.00	2.74		
24	333 - Mottville	605	110.00	4.00	1.62		
25	333 - Twin Branch	5,998	132.00	4.00	1.99		
26	334 - Berrien Springs	1,213	128.00	4.00	1.96		
27	334 - Buchanan	1,024	117.00	4.00	1.81		
28	334 - Constantine	463	132.00	26.00	2.03		
29	334 - Elkhart	461	117.00	2.00	2.90		
30	334 - Mottville	713	110.00	4.00	1.91		
31	334 - Twin Branch	1,660	132.00	4.00	1.75		
32	335 - Berrien Springs	790	128.00	4.00	2.52		
33	335 - Buchanan	288	117.00	4.00	2.43		
34	335 - Constantine	353	132.00	26.00	2.56		
35	335 - Crew Service Cen	127		4.00	0.86		
36	335 - Elkhart	220	117.00	2.00	4.43		
37	335 - Mottville	383	110.00	4.00	3.89		
38	335 - Twin Branch	604	132.00	4.00	2.92		
39	336 - Mottville	1	110.00	4.00	0.67		
40	TOTAL HYDRO	54,618					
41							
42	OTHER GENERATION						
43	341 - Olive Solar	377	20.00	4.00	5.28		
44	341 - Watervliet Solar	358	20.00	3.00	5.23		
45	344 - Deer Creek Solar	6,127	20.00	3.00	5.35		
46	344 - Olive Solar	11,185	20.00	4.00	5.27		
47	344 - Twin Branch Sola	6,955	20.00	4.00	5.27		
48	344 - Watervliet Solar	11,113	20.00	3.00	5.21		
49	345 - Olive Solar	269	20.00	4.00	5.25		
50	346 - Deer Creek Solar	5	20.00	3.00	5.35		

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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 - Olive Solar	215	20.00	4.00	5.29		
13	346 - Watervliet Solar	344	20.00	3.00	5.24		
14	TOTAL SOLAR	36,948					
15							
16	TRANSMISSION						
17	350 (Rights)	60,647	65.00		1.47	R5	
18	352	29,862	73.00	18.00	1.53	R3.5	
19	353	760,124	51.00	-3.00	1.85	L0.5	
20	353.16	2,107	51.00	-3.00	1.85	L0.5	
21	354	232,914	64.00	20.00	1.65	R5	
22	355	188,692	53.00	53.00	2.84	L0.5	
23	356	267,873	64.00	34.00	1.94	R4	
24	356.16	2	64.00	34.00	1.94	R4	
25	357	2,312	50.00		1.83	L5	
26	358	6,187	65.00	30.00	1.69	L2.5	
27	359	91	65.00		1.49	R5	
28	TOTAL TRANSMISSION	1,550,811					
29							
30	DISTRIBUTION						
31	360 (Rights) - IN	9,420	65.00		1.50	R5	
32	360 (Rights) - MI	5,384	65.00		1.50	R5	
33	361 - IN	25,151	75.00	10.00	1.44	R2	
34	361 - MI	3,220	75.00	10.00	1.44	R2	
35	362 - IN	298,184	50.00	3.00	2.03	L0	
36	362 - MI	68,815	50.00	3.00	2.02	L0	
37	362.16 - IN	541	50.00	3.00	2.03	L0	
38	362.16 - MI	108	50.00	3.00	2.02	L0	
39	363 - IN	5,608	15.00		6.08	SQ	
40	364 - IN	216,639	33.00	78.00	5.25	L0	
41	364 - MI	69,243	33.00	78.00	5.22	L0	
42	365 - IN	339,599	33.00	10.00	3.27	L0	
43	365 - MI	126,818	33.00	10.00	3.26	L0	
44	366 - IN	110,430	53.00		1.84	R2	
45	366 - MI	11,299	53.00		1.83	R2	
46	367 - IN	225,714	50.00		1.96	R1	
47	367 - MI	36,100	50.00		1.95	R1	
48	368 - IN	286,258	20.00	6.00	5.00	R0.5	
49	368 - MI	48,763	20.00	6.00	4.95	R0.5	
50	369 - IN	153,437	38.00	20.00	3.05	R0.5	

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	369 - MI	31,207	38.00	20.00	3.03	R0.5	
13	370 - IN	77,147	15.00	22.00	6.78	SQ	
14	370 - MI	17,218	9.00	22.00	13.22		
15	370.16	3,715			10.00		
16	371 - IN	19,124	13.00	23.00	9.04	L0	
17	371 - MI	8,257	13.00	23.00	8.96	L0	
18	373 - IN	16,601	18.00	12.00	5.57	R0.5	
19	373 - MI	4,990	18.00	12.00	5.44	R0.5	
20	TOTAL DISTRIBUTION	2,218,990					
21							
22	GENERAL PLANT						
23	390	52,234	50.00	-1.00	2.04	L0.5	
24	391	6,031	22.00	-5.00	4.69	SQ	
25	393	916	14.00		4.11	SQ	
26	394	15,487	16.00		6.70	SQ	
27	395	241	20.00	-1.00	5.47	SQ	
28	396	544	25.00		4.35	SQ	
29	397	52,465	27.00		3.83	SQ	
30	397.16	344	10.00		10.00		
31	398	10,359	30.00	-9.00	3.15	SQ	
32	TOTAL GENERAL PLANT	138,621					
33							
34	DEPRECIABLE SUM	8,212,099					
35							
36							
37							
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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.: 34   Column: b

The Depreciable plant base is the November 30, 2018 total company deprciable plant.

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) *Miscellaneous Amortization* (Account 425)-Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) *Miscellaneous Income Deductions* -- Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) *Interest on Debt to Associated Companies* (Account 430) -- For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) *Other Interest Expense* (Account 431) -- Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1	425 MISCELLANEOUS AMORTIZATION	
2	None	0
3		
4	426 Other Income Deductions	
5		
6	426.1 DONATIONS	
7	Community Chest	857,367
8	Service Organization	860,098
9	School, Colleges, and Universities	109,518
10	Other minor items.	107,709
11		
12		
13	Subtotal 426.1 Items	1,934,692
14		
15	426.3 PENALTIES	
16	NERC	80,049
17	Other minor items.	1,347
18		
19		
20		
21	Subtotal 426.3 Items	81,396
22		
23	426.4 EXPENDITURES FOR CERTAIN CIVIC, POLITICAL, AND RELATED ACTIVITY	
24	AEP Service Corporation Expenses	934,140
25	Legislative and Lobbying Services	162,323
26	Business and Meeting Expenses	87,837
27	Labor Overheads	87,549
28	Nuclear Energy Institute	23,868
29	Nuclear Waste Strategy	10,000
30	Other minor items	26,177
31		
32	Subtotal 426.4 Items	1,331,894
33		
34		
35		

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) *Miscellaneous Amortization* (Account 425)-Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) *Miscellaneous Income Deductions* -- Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) *Interest on Debt to Associated Companies* (Account 430) -- For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) *Other Interest Expense* (Account 431) -- Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1	426.5 OTHER DEDUCTIONS	
2	Factored Customer Accounts Receivable Expense	9,178,277
3	Indiana Program Contributions	670,000
4	Blackhawk Coal Shutdown Costs	84,423
5	AEP Service Corporation Expenses	83,328
6	Other minor items	148,864
7		
8	Subtotal 426.5 Items	10,164,892
9		
10	TOTAL ACCOUNT 426	13,512,874
11		
12	430 MONEY POOL INTEREST	
13	Money Pool Interest	1,921,471
14		
15	431 OTHER INTEREST EXPENSE	
16	Indiana Life Cycle Management Carrying Charges	1,615,933
17	Interest on Customer Deposits	1,533,078
18	Lines of Credit	817,429
19	Fort Wayne Settlement	821,762
20	Indiana Dry Sorbent Injection Carrying Charges	(12,859)
21	Indiana Clean Coal Technology Carrying Charges	(93,290)
22	Fuel Recovery	214,709
23	Dedicated Muni/Co-Op Formula Rate True Ups	173,169
24	IPP Projects	155,635
25	ROE Interest Reserve	(174,450)
26	Issuance Expenses	63,598
27	Trans Refund Interest	7,283
28	Michigan Energy Optimization Carrying Charges	3,426
29	Interest related to FIN-48 tax adjustments	97,944
30		
31	TOTAL ACCOUNT 431	5,223,367

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

EXPENDITURES FOR CERTAIN CIVIC, POLITICAL AND RELATED ACTIVITIES
(Account 426.4)

1. Report below all expenditures incurred by the respondent during the year for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation or ordinances (either with respect to the possible adoption of new referenda, legislation or ordinances or repeal or modification of existing referenda, legislation or ordinances); approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials which are accounted for as Other Income Deductions, Expenditures for Certain Civic, Political and Related Activities, Account 426.4.
2. Advertising expenditures in this Account shall be classified according to subheadings, as follows: (a) radio, television, and motion picture advertising; (b) newspaper, magazine, and pamphlet advertising; (c) letters or inserts in customer's bills; (d) inserts in reports to stockholders; (e) newspaper and magazine editorial services; and (f) other advertising.
3. Expenditures within the definition of paragraph (1), other than advertising shall be reported according to captions or descriptions clearly indicating the nature and purpose of the activity.
4. If respondent has not incurred any expenditures contemplated by the instruction of Account 426.4, so state.
5. Minor amount may be grouped by classes if the number of items so grouped is shown.

NOTE: The classification of expenses as nonoperating and their inclusion in this amount is for accounting purposes. It does not preclude Commission consideration of proof to the contrary for ratemaking or other purposes.

Line No.	Item (a)	Amount (b)
1	Lobbying Expenses - Company Employees	$ 7,232
2	Lobbying Expenses - Third Party	37,500
3		
4		
5		
6		
7		
8		
9		
10	Total Acct 426.4	44,732
11		
12		
13		
14		
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

EXTRAORDINARY ITEMS (Accounts 434 and 435)

1. Give below a brief description of each item included in Accounts 434, Extraordinary Income and 435, Extraordinary Deductions.
2. List date of Commission approval for extraordinary treatment of any item which amounts to less than 5% on income. (See General Instruction 7 of the Uniform System of Accounts).
3. Income tax effects relating to each extraordinary item should be listed in Column (c).
4. For additional space use an additional page.

Line No.	Description of Items (a)	Gross Amount (b)	Related Income Taxes (c)
1	Extraordinary Income (Account 434):		
2	None		
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19	Total Extraordinary Income	0	0
20	Extraordinary Deductions (Account 435):		
21	None		
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39	Total Extraordinary Deductions	0	0
40	Net Extraordinary Items	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 2018/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	2,176,276		2,176,276	
3	- Annual Fees	9,079,500		9,079,500	
4					
5					
6	Hydro License Fee		36,657	36,657	
7					
8	Indiana Rate Case		723,674	723,674	1,086,689
9					
10	Michigan Rate Case		434,503	434,503	540,272
11					
12	5 Yr Dist Filing - Michigan		155,725	155,725	
13					
14	IN Perf Metric Collaboration		47,704	47,704	
15					
16	Integrated Resource Plan Filing		491,473	491,473	
17					
18	Minor Items < $25,000		94,360	94,360	
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
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42					
43					
44					
45					
46	TOTAL	11,255,776	1,984,096	13,239,872	1,626,961

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	2,176,276					2
	928	9,079,500					3
							4
							5
	928	36,657					6
							7
	928	723,674	394,113	928	245,116	1,235,685	8
							9
	928	434,503	40,654	928	92,782		10
							11
	928	155,725					12
							13
	928	47,704					14
							15
	928	491,473					16
							17
	928	94,360					18
							19
							20
							21
							22
							23
							24
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							45
		13,239,872	434,767		337,898	1,235,685	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 2018/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	2 items < $50,000
2		Generation Asset Management
3	A(1)e: Generation: Unconventional	1 item <$50,000
4	A(2): Transmission	1 item <$50,000
5	A(3): Distribution	2 items <$50,000
6	A(5): Environment (other than equipment)	1 item <$50,000
7	A(6): Other	3 items <$50,000
8	A(6)a:	1 item <$50,000
9	A(6)f: Other: Metering	1 item <$50,000
10	A(6)g: Research-General	1 item <$50,000
11	A(7) TOTAL COSTS INCURRED INTERNALLY	
12	B: Electric R&D External	6 items <$50,000
13	B(1): Research Support to Electric Research	EPRI Environmental Science
14		EPRI Environmental Controls
15		EPRI Research Portfolio
16		EPRI Nuclear Annual Research
17		IT - EPRI Annual Research Port
18		17 items <$50,000
19	(B4): Steam Power	6 items <$50,000
20		2 items <$50,000
21	B(5) TOTAL COSTS INCURRED EXTERNALLY	
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
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37		
38		

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.
32,642		506,524	32,642		1
71,217		506	71,217		2
392		506	392		3
11,946		566	11,946		4
7,073		588	7,073		5
103		506	103		6
23,514		various	23,514		7
7,359		506	7,359		8
3,896		588	3,896		9
5,210		566,588	5,210		10
163,352			163,352		11
	47,471	various	47,471		12
	584,986	506	584,986		13
	171,487	506	171,487		14
	381,644	various	381,644		15
	1,443,395	524	1,443,395		16
	114,585	various	114,585		17
	29,014	various	29,014		18
	49,508	506	49,507		19
	2,576	566	2,576		20
	2,824,666		2,824,665		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 2018/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	85,531,363		
4	Transmission	2,415,492		
5	Regional Market			
6	Distribution	9,693,926		
7	Customer Accounts	3,408,538		
8	Customer Service and Informational	3,892,280		
9	Sales	935		
10	Administrative and General	3,194,865		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	108,137,399		
12	Maintenance			
13	Production	52,833,494		
14	Transmission	2,278,887		
15	Regional Market			
16	Distribution	9,071,875		
17	Administrative and General	1,704,560		
18	TOTAL Maintenance (Total of lines 13 thru 17)	65,888,816		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	138,364,857		
21	Transmission (Enter Total of lines 4 and 14)	4,694,379		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	18,765,801		
24	Customer Accounts (Transcribe from line 7)	3,408,538		
25	Customer Service and Informational (Transcribe from line 8)	3,892,280		
26	Sales (Transcribe from line 9)	935		
27	Administrative and General (Enter Total of lines 10 and 17)	4,899,425		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	174,026,215	8,129,507	182,155,722
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			

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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)	174,026,215	8,129,507	182,155,722
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	45,748,624	2,137,114	47,885,738
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	45,748,624	2,137,114	47,885,738
72	Plant Removal (By Utility Departments)			
73	Electric Plant	6,475,666	302,506	6,778,172
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	6,475,666	302,506	6,778,172
77	Other Accounts (Specify, provide details in footnote):			
78	120 - Nuclr Fuel in Proc of Refinmnt	453,991		453,991
79	124 - Other Assets	3,031		3,031
80	152 - Fuel Stock Undistributed	2,925,606		2,925,606
81	163 - Stores Expense Undistributed	7,481,757	-7,481,757	
82	183 - Prelim Survey	-267,206	267,206	
83	184 - Clearing Accounts	3,354,576	-3,354,576	
84	185 - ODD Temporary Facilities	109,895		109,895
85	186 - Misc Deferred Debits	2,257,381		2,257,381
86	188 - Research & Development	-2,006		-2,006
87	228 - RAD Waste Accrual	64,949		64,949
88	401 - Operation Expense - Nonassociated	427		427
89	417 - Misc Exp	17,209,585		17,209,585
90	426 - Political Activities	90,054		90,054
91				
92				
93				
94				
95	TOTAL Other Accounts	33,682,040	-10,569,127	23,112,913
96	TOTAL SALARIES AND WAGES	259,932,545		259,932,545

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.

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2018

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES

1. Report the information specified below for all charges made during the year included in any account (including plant accounts) for outside consultative and other professional services. (These services include rate, management, construction, engineering research, financial, valuation, legal, accounting, purchasing, advertising, labor relations, and public relations, rendered the respondent under written or oral arrangement, for which aggregate payments were made during the year to any corporation, partnership, organization of any kind, or individual (other than for services as an employee or for payments made for medical and related services) amounting to more than $250,000, including payments for legislative services, except those which should be reported in Account 426.4, Expenditures for Certain Civic, Political and Related Activities.)
   (a) Name and address of person or organization rendering services,
   (b) description of services received during year and project or case to which services relate,
   (c) basis of charges,
   (d) total charges for the year, detailing utility department and account charged.
2. For any services which are of a continuing nature, give the date and term of contract and date of Commission authorization, if contract received Commission approval.
3. Designate with an asterisk associated companies.

1 a. American Electric Power Service Corporation - * (Associated Company)
1 Riverside Plaza
Columbus, Ohio 43215-2373

b. American Electric Power Service Corporation renders management and advisory services to American Electric Power Company, Inc. (Parent) and its subsidiary companies. Such services furnished include, but are not limited to: administrative, planning & engineering, financial and accounting management, legal, fuel & material procurement, pension & employee benefits administration, and other technical services.

c. The services are provided on a non-profit basis. Under a work order system, costs are identified and billed directly to the company benefiting from the service rendered to the extent practical. Other costs that cannot be directly attributed to particular companies are collected on work orders which are allocated to the companies based on the appropriate factor.

2. Date of Contract - June 15,2000 (supercedes contract dated January 1, 1980)
Term of Contract - Indeterminate
AEPSC activities are authorized by the FERC under the Public Utility Holding Company Act of 2005
Date of SEC Authorization - June 14, 2000

Total charges for the year and Utility Department and account charged

			ACCOUNT	AMOUNT
Electric	Construction Work in Progress		107	71,040,789
	Retirement Work in Progress		108	545,761
	Nuclr Fuel in Proc of Refinmnt		120	11,807
	Nonutility Property		121	241,449
	Other Investments		124	3,983
	Fuel Stock Undistributed		152	1,770,193
	Clearing Accounts		163	4,887,300
	Preliminary Survey & Investig. Charges		183	125,200
	Misc Deferred Debits		186	109,206
	Deferred Debits-R&D		188	1,536,632
	Current & Accrued Liabilities		242	127
	Non-Utility Operations Revenue		417	1,613,606
	Non-Operating Rental Income		418	880
	Misc Non-Operating Revenues		421	25,314
	Other Income Deductions		426	1,084,071
Electric	Account 401	Operating Expense	500	7,246,477
			501	133,596
			502	60,458
			505	4,223
			506	88,541
			517	33,903
			519	(2,717)
			520	(1)
			524	828,603
			535	558,596
			536	29,109
			537	31,570
			538	9,618
			539	734,248
			546	95,302
			547	5
			549	85,199
			555	(6)
			556	2,332,482
			557	3,882,055
			560	4,622,443

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Electric	Account 401	Operating Expense (contd.)	561	485,422
			562	14,886
			563	45,563
			566	1,232,475
			580	1,254,796
			582	105,708
			583	43
			584	16,740
			586	252,046
			588	1,616,628
			589	509
			598	1,202
			901	52,198
			902	159,985
			903	8,471,831
			905	29,837
			907	193,292
			908	130,290
			909	417
			910	13,636
			911	9
			912	193,658
			920	32,034,059
			921	2,269,981
			923	6,805,020
			924	811
			925	29,224
			926	112,385
			928	1,253,231
			930	696,307
			931	34,214
Electric	Account 401	Total Operating Expense		78,280,107
Electric	Account 402	Maintenance Expense	510	755,179
			511	31,309
			512	743,255
			513	1,514,191
			514	27,583
			528	176,355
			530	1,058,242
			531	23,892
			532	0
			541	7,601
			542	92,829
			543	61,344
			544	341,624
			545	12,298
			548	0
			553	6
			568	77,247
			569	252,242
			570	218,914
			571	222,733
			572	794
			573	20,178
			590	15,887
			591	1,710
			592	118,798
			593	44,384
			594	(46)
			595	0
			597	653
			935	5,060,821
Electric	Account 402	Total Maintenance Expense		10,880,023
		Total O&M		$ 89,160,130
		Total AEP Service Corp charges		172,156,448

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Charges for Outside Professional & Other Consulting Services - Payments of $250,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
ADM ASSOCIATES INC 3239 RAMOS CIR SACRAMENTO CA 95827-2501	environmental consulting services	Invoice Cost	908	892,686
ALDRIDGE ELECTRIC INC. 844 E. ROCKLAND AVENUE LIBERTYVILLE, IL 60048	power & utility services	Invoice Cost	107, 186	9,641,765
ALSTOM POWER INC PO BOX 73729 CHICAGO IL 60673-7729	inspection & measurement services	Invoice Cost	107	1,088,829
AMPP CONSTRUCTION INC PO BOX 65 WINCHESTER IN 47394	construction services	Invoice Cost	186	364,030
APPLIANCE RECYCLING CTRS OF AMER PO BOX 31001-1526 PASADENA CA 91110-1526	appliance recycling services	Invoice Cost	908	485,407
APTIM SERVICES LLC 150 ROYALL ST CANTON MA 02021	nuclear services	Invoice Cost	107, 108, 163, 517, 520, 524, 529, 530, 531, 532	2,549,427
ARC AMERICAN INC PO BOX 599 WAKARUSA IN 46573	contracting services	Invoice Cost	107, 186, 588	4,970,194
AREA WIDE PROTECTIVE PO BOX 92362 CLEVELAND OH 44193	traffic control services	Invoice Cost	107, 108, 186, 571, 583, 584, 586, 588, 593, 594	2,336,579
ASPLUNDH CONSTRUCTION CORP 481 SCHROCK RD COLUMBUS OH 43229	construction contracting services	Invoice Cost	107, 108, 185, 186, 588, 593, 594, 930	15,615,097
ASPLUNDH TREE EXPERT 950 TAYLOR STATION RD COLUMBUS, OH 43230	tree trimming services	Invoice Cost	107, 186, 593	14,567,056
BLACK & VEATCH CORPORATION PO BOX 803823 KANSAS CITY MO 64180-3823	engineering services	Invoice Cost	107, 108, 566	7,457,338
BMWC CONSTRUCTORS INC PO BOX 22210 INDIANAPOLIS IN 46222	environmental construction services	Invoice Cost	107	3,522,711
BROWN SERVICES CO LLC P.O. BOX 64 WHEELERSBURG, OH 45694	occupational safety services	Invoice Cost	107, 183, 500, 510	313,700
BRUCE & MERRILEES ELECTRIC CO INC 930 CASS ST NEW CASTLE PA 16101	electrical services	Invoice Cost	107, 108	668,164
BURNS & MCDONNELL PO BOX 411883 KANSAS CITY MO 64141-1883	engineering services	Invoice Cost	107, 108	2,530,711
CIANBRO CORPORATION PO BOX 983122 BOSTON MA 02298-3122	engineering consulting services	Invoice Cost	107, 108	2,798,529
CLEARESULT CONSULTING INC 4301 WESTBANK DRIVE AUSTIN, TX 78746	energy management services	Invoice Cost	908	593,843

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NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
COMMONWEALTH ASSOCIATES INC 2700 W ARGYLE ST JACKSON MI 49202	electrical engineering & design services	Invoice Cost	107, 108, 566	879,929
CONTRACT LAND STAFF LLC 2245 TEXAS DR STE 200 SUGAR LAND TX 77479	staffing services	Invoice Cost	107, 108	2,976,264
DAVEY RESOURCE GROUP P O BOX 5193 KENT OH 44240-5193	tree trimming services	Invoice Cost	107, 108, 571, 593	3,311,771
DAVIS H ELLIOT COMPANY INC PO BOX 37251 BALTIMORE MD 21297-3251	electrical contractor services	Invoice Cost	186	426,662
DLZ INDUSTRIAL LLC 6121 HUNTLEY RD COLUMBUS, OH 43229	network rebuild services	Invoice Cost	107, 186	1,047,064
DUE NORTH AVIATION LLC 3380 OLD COLUMBUS RD NW CARROLL, OH 43112	commercial helicopter services	Invoice Cost	563, 571	266,729
EASI LLC PO BOX 198531 ATLANTA GA 30384-8531	employment services	Invoice Cost	107, 108, 563, 566, 588	619,471
EC SOURCE SERVICES LLC 16055 SPACE CENTER BLVD STE 700 HOUSTON TX 77062	substation electrical services	Invoice Cost	107, 108	1,564,263
ECSL 181 MONTOUR RUN ROAD CORAPOLIS, PA 15108	marketing services	Invoice Cost	107, 108	3,491,332
EDKO LLC PO BOX 7241 SHREVEPORT LA 71137	perimeter security services	Invoice Cost	107, 549, 593	2,212,205
EDWARDS MOVING & RIGGING INC 200 EVERETT HALL RD SHELBYVILLE KY 40065	rigging services	Invoice Cost	107, 108	293,300
ELECTRIC POWER SYSTEMS 15 MILLPARK COURT MARYLAND HEIGHTS MO 63043	construction services	Invoice Cost	107, 108	798,445
ELECTRICAL CONSULTANTS INC 3521 GABEL ROAD BILLINGS, MT 59102	planning services	Invoice Cost	107, 108	3,545,008
EPC SERVICES COMPANY 1241 S 31ST ST W BILLINGS, MT 59102	planning services	Invoice Cost	107, 108	1,911,736
FIRST CLASS SERVICES INC PO BOX 478 LEWISPORT KY 42351	trucking services	Invoice Cost	506	396,801
FISHER CONTRACTING COMPANY 3401 CONTRACTOR DR MIDLAND MI 48641-1787	gate replacement services	Invoice Cost	107, 108, 542, 543	552,385
FRAMATOME INC 29988 NETWORK PL CHICAGO, IL 60673-1299	motor refurbishment services	Invoice Cost	165, 524, 530	500,434

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NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
G & L CORPORATION 3101 BROOKLYN AVE FORT WAYNE, IN 46809	equipment moving services	Invoice Cost	107, 108, 520, 570 588	853,971
GAYLOR GROUP INC 5750 CASTLE CREEK PKWY N DRIVE INDIANAPOLIS, IN 46250	electrical contracting services	Invoice Cost	107, 108	2,481,270
GE GRID SOLUTIONS LLC PO BOX 743504 ATLANTA GA 30374-3504	grid consulting services	Invoice Cost	107, 560, 566	379,400
GE INTERNATIONAL INC 12505 COLLECTIONS CENTER CHICAGO IL 60693	electrical services	Invoice Cost	107, 108, 523, 530, 531, 532	1,008,549
GEOFORCE UTILITY TECHNOLOGIES 1202 NORTH INGLESIDE FARM ROAD IRON STATION, NC 28080	utility consulting services	Invoice Cost	186, 583	1,100,131
GRIBBINS INSULATION COMPANY 1400 E. COLUMBUA STREET EVANSVILLE, IN 47711	insulation contracting services	Invoice Cost	107, 108, 186, 511 512, 513	592,288
HELICOPTER MINIT-MEN INC PO BOX 21758 COLUMBUS OH 43221-0758	right-of-way maintenance services	Invoice Cost	571	827,822
HOLTEC INTERNATIONAL 1 HOLTEC BLVD CAMDEN NJ 08104	nuclear & engineering services	Invoice Cost	107, 520	8,670,713
HONEYWELL INTERNATIONAL INC 101 COLUMBIA ROAD MORRISTOWN, NJ 07962	industrial & security system supplies	Invoice Cost	908	496,864
IJUS LLC 690 TAYLOR RD STE 100 GAHANNA OH 43230	engineering services	Invoice Cost	107, 108, 186, 580	2,237,042
INDUSTRIAL CONTRACTORS SKANSKA IN(PO BOX 208 EVANSVILLE IN 47702-0208	equipment repairs	Invoice Cost	107, 108, 183, 511, 512, 513, 514, 560	12,867,766
INSERV INC 514 E MARION ST MISHAWAKA IN 46545	building maintenance services	Invoice Cost	107, 108, 186, 570, 580, 588, 592, 593	1,219,685
INTEGRITY TREE SERVICES LLC 2300 SANFORD AVE SW GRANDVILLE, MI 49418	tree trimming services	Invoice Cost	107, 571	1,115,342
KENT POWER INC PO BOX 327 KENT CITY MI 49330	power line relocation	Invoice Cost	107, 108	5,763,355
KOKOSING INDUSTRIAL INC 6235 WESTERVILLE RD STE 200 WESTERVILLE OH 43081-4074	construction services	Invoice Cost	107, 108, 571	1,526,423
KWEST GROUP LLC 8305 FREMONT PIKE PERRYSBURG OH 43551	excavation & site preparation	Invoice Cost	107, 108	1,586,738
LEWIS TREE SERVICE INC. 1500 BROMMER STREET SANTA CRUZ, CA 95062	tree trimming services	Invoice Cost	107, 186, 593	4,749,883

Charges for Outside Professional & Other Consulting Services - Payments of $250,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
LOCKHEED MARTIN 5600 SAND LAKE RD MP 264 ORLANDO FL 32819-8907	engineering services	Invoice Cost	908	1,832,700
M J ELECTRIC INC. 1190 ERIE COURT CROWN POINT, IN 46307	electrical contracting services	Invoice Cost	107, 108, 571	12,953,246
MICHIANA LAND SERVICES INC 505 PLEASANT ST ST JOSEPH, MI 49085	land right of way services	Invoice Cost	107, 108	1,703,995
MOFFITT RE-HAB SERVICE INC PO BOX 488 HAWESVILLE KY 42348	excavation & site preparation	Invoice Cost	501, 506	1,430,687
MPW ENVIRONMENTAL SERVICES 9711 LANCASTER RD SE HEBRON, OH 43025	plant equipment maintenance & cleaning	Invoice Cost	107, 152, 501, 502 511, 512, 513	1,373,752
NELSON TREE SERVICE INC 350 E DEVON AVE #774489 ITASCA IL 60143	tree trimming services	Invoice Cost	107, 108, 571, 582 593	4,816,738
NEW RIVER ELECTRICAL CORP PO BOX 70 CLOVERDALE VA 24077-0070	storm restoration services	Invoice Cost	107, 108	3,227,241
NEWKIRK ELECTRIC ASSOCIATES 1875 ROBERTS STREET MUSKEGON, MI 49442	electrical construction services	Invoice Cost	107, 108, 571, 930	10,595,912
NILES INDUSTRIAL LLC 201 S ALLOY DR FENTON, MI 48430	industrial coating services	Invoice Cost	542	430,000
NORTH AMERICAN PROTECTION & CONTROL PO BOX 102606 ATLANTA, GA 30368	substation engineering services	Invoice Cost	107, 108	452,575
ORC UTILITY & INFRASTRUCTURE LAND SVCS 7005 SHANNON WILLOW RD STE 100 CHARLOTTE NC 28226	land & utility services	Invoice Cost	107	1,002,527
OSMOSE UTILITIES SERVICES INC PO BOX 8000560 BUFFALO NY 14267	energy utility services	Invoice Cost	186, 583, 584, 593 594	520,878
POWER ENGINEERS INC P O BOX 1066 HAILEY ID 83333	engineering consulting services	Invoice Cost	107, 108	559,990
POWER GRID ENGINEERING LLC 100 COLONIAL CENTER PKWY STE 400 LAKE MARY FL 32746	engineering services	Invoice Cost	107, 108	409,131
PREMIER POWER MAINTENANCE CORP. 6525 GUION ROAD INDIANAPOLIS, IN 46268	electrical engineering services	Invoice Cost	107, 108	508,415
PULVERIZER SERVICES, INC 200 PARK LOOP CALHOUN, KY 42327	plant equipment rebuilding services	Invoice Cost	107, 108, 512	264,059
QUALITY NUCLEAR SERVICES INC PO BOX 329 DARDANELLE AR 72834	nuclear services	Invoice Cost	107, 108, 520	816,097

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RCM TECHNOLOGIES INC PO BOX 536342 PITTSBURGH PA 15253-5905	site testing services	Invoice Cost	107	348,401
ROBERT HENRY CORPORATION PO BOX 1407 SOUTH BEND IN 46624-1407	construction services	Invoice Cost	107, 108, 186, 542 571, 588, 593, 594 930, 935	20,984,127
SABER POWER SERVICES LLC 9841 SABER POWER LN ROSHARON TX 77583	substation maintenance services	Invoice Cost	107, 108	336,958
SAFE POWER PARTNERS LLC 7915 SOUTH EMERSON AVENUE INDIANAPOLIS, IN 46237	safety consulting services	Invoice Cost	152, 501, 506	385,397
SAM INC/ SURVEYING & MAPPING INC PO BOX 732449 DALLAS, TX 75373-2449	surveying services	Invoice Cost	107	483,103
SAP AMERICA INC PO BOX 7780-824024 PHILADELPHIA PA 19182-4024	business software services	Invoice Cost	107, 108, 163, 186, 506, 510, 514, 580, 588, 930, 935	1,100,686
SARGENT & LUNDY LLC 8070 SOLUTIONS CENTER CHICAGO IL 60677-8000	nuclear engineering services	Invoice Cost	107, 108, 529	254,707
SARGENT ELECTRIC COMPANY PO BOX 6083 HERMITAGE PA 16148-1083	electrical services	Invoice Cost	107, 108	979,566
SENTIENT ENERGY INC 880 MITTEN RD STE 105 BURLINGAME CA 94010	electrical services	Invoice Cost	588	345,670
SERVICE ELECTRIC COMPANY PO BOX 277790 ATLANTA GA 30384-7790	power line services	Invoice Cost	107, 108	465,846
STRUCTURAL STEEL SERVICES INC P O BOX 2929 MERIDIAN MS 39302	engineering & design services	Invoice Cost	107	257,500
SUN TECHNICAL SERVICES INC PO BOX 405304 ATLANTA GA 30384-5304	engineering services	Invoice Cost	107, 108, 183, 184 500, 517, 520, 524 529, 530, 532, 926	1,508,937
SYSTEMS CONTROL PO BOX 808 IRON MOUNTAIN MI 49801	substation control services	Invoice Cost	107, 560	393,377
TCI OF ALABAMA LLC. 101 PARKWAY EAST PELL CITY, AL 35125	disposal services	Invoice Cost	107, 108	439,451
TENDRIL NETWORKS INC PO BOX 731655 DALLAS TX 75373-5373	business consulting services	Invoice Cost	588, 908	1,853,348
TERRACON CONSULTANTS INC PO BOX 959673 ST LOUIS MO 63195-9673	environmental consulting services	Invoice Cost	107, 183, 186	398,657
TOWNSEND TREE PO BOX 128 PARKER CITY IN 47368-0128	tree trimming services	Invoice Cost	107, 593	1,463,082

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TRC COMPANIES INC PO BOX 536282 PITTSBURGH PA 15253-5904	environmental engineering services	Invoice Cost	107, 108	1,161,021
TREMCO INC PO BOX 200390 PITTSBURGH, PA 1523-0390	general contractor services	Invoice Cost	107	634,833
UNDERWATER CONSTRUCTION CORP PO BOX 699 ESSEX CT 06426-0699	underwater construction services	Invoice Cost	530, 532, 542, 543	277,728
UNITED CONSTRUCTION COMPANY INC 3120 NORTHWESTERN PIKE PARKERSBURG WV 26104	construction contracting services	Invoice Cost	107, 183, 500, 501 545	2,740,335
USIC LOCATING SERVICES LLC 6879 PAYSPHERE CIRCLE CHICAGO IL 60674	power line construction services	Invoice Cost	107, 584	1,827,147
VARO ENGINEERS INC 2751 TULLER PARKWAY, SUITE 100 DUBLIN, OH 43017	engineering services	Invoice Cost	107	586,290
VAUGHN INDUSTRIES 1201 E. FINDLAY STREET CAREY, OH 43316	substation electrical work services	Invoice Cost	107, 108, 186	2,237,499
VENTURE SUM CORP 4350 MAIN ST STE 207 HARRISBURG NC 28075	field data acquisition services	Invoice Cost	186	463,982
WESTINGHOUSE ELECTRIC CO LLC PO BOX 534774 ATLANTA GA 30353-4774	nuclear support services	Invoice Cost	107, 530	311,465
WHAYNE SUPPLY CO 1400 CECIL AVENUE LOUISVILLE, KY 40211	equipment repair services	Invoice Cost	107, 108, 501, 506 512, 514	798,135
WIGHTMAN & ASSOCIATES INC 2303 PIPESTONE RD BENTON HARBOR MI 49022	topographic surveying services	Invoice Cost	107, 108	900,794
WOOD ENVIRONMENT & INFRASTRUCTURE PO BOX 74008618 CHICAGO, IL 60674-8618	environmental services	Invoice Cost	183	251,577
WOOLPERT INC PO BOX 641998 CINCINNATI OH 45264	station rebuild services	Invoice Cost	107	283,853
WORLEYPARSONS GROUP INC 1411 BROADWAY NEW YORK NY 10018	engineering services	Invoice Cost	107	3,057,044
WRIGHT TREE SERVICE INC 2943 PAYSPHERE CIRCLE CHICAGO IL 60674	tree trimming services	Invoice Cost	107, 108, 186, 511 571, 592, 593	11,242,106

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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)	18,488,640
3	Steam	5,947,057			
4	Nuclear	17,610,814	23	Requirements Sales for Resale (See instruction 4, page 311.)	4,607,481
5	Hydro-Conventional	115,150			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	7,007,305
7	Other	20,748			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	69
9	Net Generation (Enter Total of lines 3 through 8)	23,693,769	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	8,257,977	27	Total Energy Losses	1,848,251
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	31,951,746
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)	31,951,746			

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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	3,536,592	1,295,113	3,723	16	1000
30	February	2,473,710	534,723	3,538	8	800
31	March	2,389,256	310,323	3,317	12	1100
32	April	2,081,599	200,759	3,264	17	1100
33	May	2,430,943	396,999	4,103	29	1500
34	June	2,920,079	831,164	4,369	18	1600
35	July	2,727,073	467,321	4,221	10	1400
36	August	2,843,869	552,934	4,257	28	1700
37	September	2,556,504	535,754	4,286	4	1800
38	October	2,737,714	814,282	3,608	9	1600
39	November	2,577,826	615,587	3,360	15	1000
40	December	2,676,581	632,154	3,407	10	1100
41	TOTAL	31,951,746	7,187,113			

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Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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)	664			659		
7	Plant Hours Connected to Load	6117			6268		
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	3086952000			2860105000		
13	Cost of Plant: Land and Land Rights	6477506			67771		
14	Structures and Improvements	98543833			7284899		
15	Equipment Costs	798221450			181273488		
16	Asset Retirement Costs	7210837			7431228		
17	Total Cost	910453626			196057386		
18	Cost per KW of Installed Capacity (line 17/5) Including	1379.4752			301.6267		
19	Production Expenses: Oper, Supv, & Engr	2368725			2421880		
20	Fuel	75964134			73315524		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	8692559			8532167		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	914694			780134		
26	Misc Steam (or Nuclear) Power Expenses	2328744			2178104		
27	Rents	0			70147250		
28	Allowances	612160			612160		
29	Maintenance Supervision and Engineering	1299574			1298207		
30	Maintenance of Structures	785575			328571		
31	Maintenance of Boiler (or reactor) Plant	6128955			5785543		
32	Maintenance of Electric Plant	1423735			2801492		
33	Maintenance of Misc Steam (or Nuclear) Plant	630184			504201		
34	Total Production Expenses	101149039			168705233		
35	Expenses per Net KWh	0.0328			0.0590		
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 2018/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	2327	6
8549	8549	8760	7
0	0	0	8
1310	2620	2288	9
1308	2615	2154	10
0	239	1138	11
5947057000	11894114000	17610814000	12
6545277	13061228	1879588	13
105828732	213403697	428510877	14
979494938	1949609211	2787602486	15
14642065	29266049	439029648	16
1106511012	2205340185	3657022599	17
844.6649	841.7329	1600.4475	18
4790605	9464535	22131985	19
149279658	298560723	117690451	20
0	0	7331878	21
17224726	33462299	14183623	22
0	0	0	23
0	0	0	24
1694828	3389667	4724834	25
4506848	8040006	73313509	26
70147250	138430267	0	27
1224320	1224320	0	28
2597781	5173540	10358614	29
1114146	2228310	4733633	30
11914498	23833050	81885369	31
4225227	8450374	19192287	32
1134385	2268825	19377398	33
269854272	534525916	374923581	34
0.0454	0.0449	0.0213	35

(d)			(e)			(f)			Line No.
Coal	Oil		Coal	Oil		Nuclear			36
Tons	Barrels		Tons	Barrels					37
3386119	14781	0	6772238	29563	0	0	0	0	38
8656	136780	0	8656	136780	0	0	0	0	39
43.723	88.958	0.000	43.723	88.958	0.000	0.000	0.000	0.000	40
43.740	79.096	0.000	43.741	79.096	0.000	0.000	0.000	0.000	41
2.527	13.768	0.000	2.527	13.768	0.000	0.650	0.000	0.000	42
0.025	0.000	0.000	0.025	0.000	0.000	0.007	0.000	0.000	43
10101.000	0.000	0.000	10101.000	0.000	0.000	10274.000	0.000	0.000	44

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.

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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 2018/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	6.2	37,907	15,055,267
3	Buchanan	1919	4.10	2.6	15,997	7,998,932
4	Constantine	1921	1.00	0.8	4,327	3,242,560
5	Elkhart	1913	3.44	2.9	17,858	9,826,606
6	Mottville	1923	1.68	1.4	7,681	4,731,837
7	Twin Branch	1904	4.80	4.3	31,380	14,263,862
8						
9						
10						
11	Solar electric					
12	Deer Creek	2015	2.50	2.5	1,419	6,144,393
13	Olive	2016	5.00	5.5	8,067	12,062,064
14	Twin Branch	2016	2.60	2.8	3,892	6,958,803
15	Watervliet	2016	4.60	4.9	7,370	11,965,896
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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 2018/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 Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
2,091,009	560,651		346,619			2
1,950,959	350,700		978,724			3
3,242,560	138,784		225,865			4
2,856,572	308,281		382,876			5
2,816,570	183,466		230,236			6
2,971,638	498,825		812,744			7
						8
						9
						10
						11
2,457,757	167,551		1			12
2,412,413	128,377		2			13
2,676,463	83,093		1			14
2,601,282	130,932		1			15
						16
						17
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

CHANGES MADE OR SCHEDULED TO BE MADE IN GENERATING PLANT CAPACITIES

Give below the information called for concerning changes in electric generating plant capacities during the year.

A. Generating Plants or Units Dismantled, Remove from Service, Sold, or Leased to Others During Year

1. State in column (b) whether dismantled, removed from service, sold, or leased to another. Plants removed from service include those not maintained for regular or emergency service.

2. In column (f), give date dismantled, removed from service, sold, or leased to another. Designate complete plants as such.

Line No.	Name of Plant (a)	Disposition (b)	Installed Capacity (in megawatts) Hydro (c)	Steam (d)	(Other) (e)	Date (f)	If Sold or Leased, Give Name and Address of Purchaser or Lessee (g)
1	None						
2							
3							
4							
5							
6							
7							

B. Generating Units Scheduled for or Undergoing Major Modifications

Line No.	Name of Plant (a)	Character of Modification (b)	Installed Plant Capacity After Modification (in MW) (c)	Estimated Dates of Construction Start (d)	Completion (e)
8	Rockport Plant Unit 2	Selective Catalytic Reduction	1,300	Jun-18	Jun-20
9					
10					
11					
12					
13					
14					

C. New Generating Plants Scheduled for or Under Construction

Line No.	Plant Name & Location (a)	TYPE (Hydro, pumped storage, steam, internal comb., gas-turbine, nuclear, wind, solar, biomass, etc. (b)	Installed Capacity (in megawatts) Initial (c)	Ultimate (d)	Estimated Dates of Construction Start (e)	Completion (f)
15	None					
16						
17						
18						
19						
20						
21						

D. New Units in Existing Plants Scheduled for or Under Construction

Line No.	Plant Name & Location (a)	TYPE (Hydro, pumped storage, steam, internal comb., gas-turbine, nuclear, wind, solar, biomass, etc. (b)	Unit (c)	Size of Unit (in megawatts) (d)	Estimated Dates of Construction Start (e)	Completion (f)
22	None					
23						
24						
25						
26						
27						
28						

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) #REF!	12/31/18

STEAM ELECTRIC GENERATING PLANTS

1. Include on this page steam-electric plants of 25,000 Kw (name plate rating) or more of installed capacity.
2. Report the information called for concerning generating plants and equipment at year end. Show unit type Installation, boiler, and turbine-generator on same line.
3. Exclude plant, the book cost of which is located in Account 121, *Nonutility Property.*
4. Designate any generating plant 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 term of lease, and annual rent. For any generating plant, other than a leased plant or portion thereof for which the respondent is not the sole owner but which the respondent operates or share in the of, furnish a succinct statement explaining the arrangement and giving details as to such matters as percent ownership by respondent, name of co-owner, basis of sharing output, expenses or revenues, and how expenses and/or revenues are accounted for and accounts affected. Specify if lessor, co-owner, or other party is an associated company.
5. Designate any generating plant or portion thereof leased to another company and give name of lessee, date and term of lease and annual rent, and how determined. Specify whether lessee is an associated company.
6. Designate any plant or equipment owned, not

Line No.	Name of Plant	Location of Plant	BOILERS *(Include both ratings for the boiler and the turbine-generator or dual-rated installations)*				
			Number and Year Installed	Kind of Fuel And Method of Firing	Rated Pressure (In psig)	Rated Steam Temp. *(Indicate reheat boilers as 1050/1000)*	Rated Max. Continuous M lbs. Steam per Hour
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Donald C. Cook Plant	Bridgman, MI	1 - 1975	Nuclear	2485	600	15,600
2			2 - 1978	Nuclear	2485	600	14,740
3							
4							
5							
6							
7	Rockport Plant*	Rockport, IN	1 - 1984	Pulv. Coal	3650	1000/1000	9,775
8							
9			2 - 1989	Pulv. Coal	3650	1000/1000	9,775
10							
11							
12							
13	* Figures shown are the totals for the plant which is shared one-half by respondent and one-half by AEP Generating						
14	Company (an associated company). Both companies are subsidiaries of American Electric Power Company.						
15	Operating expenses are shared on the basis of ownership percentage. Unit 1 is owned 50% by each and						
16	Unit 2 is leased 50% by each from a consortium of financial institutions.						
17							
18							
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) #REF!	12/31/18

STEAM ELECTRIC GENERATING PLANTS (cont'd)

operated, and not leased to another company. If such plant or equipment was not operated within the past year, explain whether it has been retired in the books of account or what disposition of the plant or equipment and its book cost are contemplated.

7. Report gas-turbines operated in a combined cycle with a conventional steam unit with its associated steam unit.

Turbine-Generators

(Report cross-compound turbine generator units on two lines-H.P. section and I.P. section. Designate units with shaft connected boiler feed pumps. Give capacity rating of pumps in terms of full load requirements.)

	TURBINES (*Include both ratings for boiler and turbine-generator of dual-rated installations*)				GENERATORS							
					NAME PLATE Rating in Kw		Hydrogen Pressure (*Designate air cooled generators*)					
Year Installed	Max. Rating Mega-Watt	Type (Indicate tandem-compound (TC); cross compound (CC) single casing (SC); topping unit (T); and non-condensing (NC) Show back pressures)	Steam Pressure at Throttle psia.	RPM	At Minimum Hydrogen Pressure	At Max. Hydrogen Pressure (Include both ratings for the boiler and the turbine-generator of dual-rated installations)	Min.	Max.	Power Factor	Voltage (in MV) (If other than 3 phase, 60 cycle indicate other characteristic)	Plant Capacity Maximum Generator Name Plate Rating (Should agree with column (n))	Line No.
(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	
1975	1149	TC	728	1,800	771,840	1,152,000	30	75	0.90	26	1,152,000	1
1978	1255	TC	808	1,800	1,225,000	1,225,000	60	60	0.90	26	1,225,000	2
											2,377,000	3
												4
												5
												6
1984	650	CC	600	3,600	600,000	650,000	45	65	0.90	26	1,300,000	7
1984	650	CC	3,650	3,600	600,000	650,000	45	65	0.90	26		8
1989	650	CC	600	3,600	600,000	650,000	45	65	0.90	26	1,300,000	9
1989	650	CC	3,650	3,600	600,000	650,000	45	65	0.90	26		10
											2,600,000	11
												12
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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 2018/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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (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	92.22		2
15	0677 BREED	DEQUINE EAST	345.00	345.00	1	0.18		2
16	0677 BREED	DEQUINE EAST	345.00	345.00	1	3.77		2
17	0677 BREED	DEQUINE EAST	345.00	345.00	1	0.08		2
18	0678 DEQUINE	OLIVE	345.00	345.00	3	13.31		2
19	0678 DEQUINE	OLIVE	345.00	345.00	3	67.90		2
20	0678 DEQUINE	OLIVE	345.00	345.00	1	0.50		2
21	0678 DEQUINE	OLIVE	345.00	345.00	1	0.14		2
22	0679 SORENSON	OLIVE	345.00	345.00	3	78.00		2
23	0680 OLIVE	GOODINGS GROVE	345.00	345.00	3	41.00		2
24	0683 DESOTO	JCT TOWER (MAR. CO)	345.00	345.00	3	53.00	6.00	1
25	0684 TANNERS CREEK	JUNCTION TOWER	345.00	345.00	3	80.00		1
26	0685 HANNA	JUNCTION TOWER	345.00	345.00	3	5.63		
27	0687 TANNERS CREEK	MIAMI FORT	345.00	345.00	3			2
28	0688 EUGENE	SIDNEY	345.00	345.00	1	0.20		1
29	0689 SORENSON-OLIVE	TWIN BRANCH	345.00	345.00	3	11.00		2
30	0690 BREED	CIPSCO	345.00	345.00	3	0.94		1
31	0690 BREED	CIPSCO	345.00	345.00	3	0.02		1
32	0691 BREED	PETERSBURG	345.00	345.00	3	0.70		1
33	0691 BREED	PETERSBURG	345.00	345.00	1	0.15		1
34	6118 ROBISON PARK	SORENSON-EAST LIMA	345.00	345.00	3	22.66		2
35	6118 ROBISON PARK	SORENSON-EAST LIMA	345.00	345.00	1	0.34		1
36					TOTAL	3,758.80	112.28	271

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 2018/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
1414 KCM								15
2303 KCM								16
2-2303 KCM								17
2303 KCM								18
1,414KCM								19
2156 KCM								20
2,303 KCM								21
1414 KCM								22
1414 KCM								23
2-954 KCM								24
2-954 KCM								25
2-954 KCM								26
2-954 KCM								27
1414 KCM								28
1563 KCM								29
2-1024 KCM								30
2-1351.5 KCM								31
2-954 KCM								32
2-1351.5 KCM								33
1414 KCM								34
1414 KCM								35
	69,585,869	693,760,138	763,346,007	340,378	12,724,083		13,064,461	36

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	6119 COOK	OLIVE	345.00	345.00	3	4.00		2
2	6122 DUMONT	OLIVE	345.00	345.00	3	14.52		2
3	6122 DUMONT	OLIVE	345.00	345.00	1	0.60		1
4	6123 DUMONT	TWIN BRANCH	345.00	345.00	3	17.00		2
5	6125 ROBISON PARK	EAST	345.00	345.00				
6	6133 DUMONT	BABCOCK	345.00	345.00	3	9.00		1
7	6145 TWIN BRANCH	COOK-ROB PARK JCT	345.00	345.00	3	6.00		2
8	6147 COOK	ROBISON PARK	345.00	345.00	3	67.41		2
9	6147 COOK	ROBISON PARK	345.00	345.00	1	0.41		
10	6148 JACKSON ROAD	SORENSON-OLIVE	345.00	345.00	3	4.00		2
11	6213 COOK-ROB-PARK JCT	ARGENTA	345.00	345.00	3	2.00		2
12	6237 JACKSON ROAD	WEST	345.00	345.00				
13	6240 TWIN BRANCH	SUBSTATION CORRIDOR	345.00	345.00				
14	6256 BREED	SULLIVAN	345.00	345.00	3	0.48		2
15	6256 BREED	SULLIVAN	345.00	345.00	3	0.75		1
16	6256 BREED	SULLIVAN	345.00	345.00	1	0.29		1
17	6259 COLLINGWOOD	SOUTH BUTLER	345.00	345.00	1	12.00		1
18	6232 GODMAN TAP		34.00	138.00				
19	0602 TWIN BRANCH	RIVERSIDE	138.00	138.00	3	6.00		2
20	0603 TWIN BRANCH	SOUTH BEND	138.00	138.00	3	5.00		1
21	0604 TWIN BRANCH	ROBISON PARK	138.00	138.00	3	42.70		2
22	0604 TWIN BRANCH	ROBISON PARK	138.00	138.00	1	0.28		2
23	0605 SOUTH BEND	MICHIGAN CITY	138.00	138.00	3			1
24	0606 ROBISON PARK	HAVILAND	138.00	138.00	3	12.01		2
25	0606 ROBISON PARK	HAVILAND	138.00	138.00	1	0.05		
26	0607 ROBISON PARK	DEER CREEK	138.00	138.00	3	28.52		2
27	0607 ROBISON PARK	DEER CREEK	138.00	138.00	1	0.12		2
28	0607 ROBISON PARK	DEER CREEK	69.00	138.00	1		0.65	1
29	0608 DEER CREEK	KOKOMO	138.00	138.00	3	1.56		1
30	0608 DEER CREEK	KOKOMO	138.00	138.00	3	5.96		1
31	0608 DEER CREEK	KOKOMO	138.00	138.00	1	0.17		1
32	0609 CONCORD TAP		138.00	138.00	3	4.00		2
33	0613 TWIN BRANCH	JACKSON ROAD	138.00	138.00	3	8.00		2
34	0614 LINCOLN TAP		138.00	138.00	3	4.00		2
35	0615 TWIN BRANCH	ROBISON PARK	138.00	138.00	3	65.83		1
36					TOTAL	3,758.80	112.28	271

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 2018/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)			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)	
2-954 KCM								1
2-954 KCM								2
2-954 KCM								3
2-954 KCM								4
								5
2-954 KCM								6
2-954 KCM								7
2-954 KCM								8
2-954 KCM								9
2303 KCM								10
2-954 KCM								11
								12
								13
1351.5 KCM								14
1351.5 KCM								15
1351.5 KCM								16
2-954 KCM								17
								18
397.5 KCM								19
397.5 KCM								20
397.5 KCM								21
1233.6 KCM								22
397.5 KCM								23
397.5 KCM								24
1233.6 KCM								25
397.5 KCM								26
1590 KCM								27
1033.5 KCM								28
336.4 KCM								29
636 KCM								30
336.4 KCM								31
397.5 KCM								32
447 KCM								33
397.5 KCM								34
477 KCM								35
	69,585,869	693,760,138	763,346,007	340,378	12,724,083		13,064,461	36

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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.
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	0616 DEER CREEK	DELAWARE	138.00	138.00	3	24.15		2
2	0617 DELAWARE	MADISON	138.00	138.00	3	18.81		2
3	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	3	55.31		2
4	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	4	0.84		2
5	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	2	0.11		2
6	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	1	0.45		2
7	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	1	0.08		
8	0725 DELAWARE	TRENTON	138.00	138.00	3,4			
9	0619 MADISON	NEW CASTLE	138.00	138.00	3	6.00	1.00	1
10	0620 TANNERS CREEK	MADISON	138.00	138.00	3	82.00		2
11	0622 JACKSON ROAD	OLIVE	138.00	138.00	3	16.29	1.00	1
12	0622 JACKSON ROAD	OLIVE	138.00	138.00	1	0.47		1
13	0623 MADISON	PENDLETON	138.00	138.00	2	5.00		1
14	0624 DRAGOON TAP		138.00	138.00	3	2.00		1
15	0625 TANNERS CREEK	COLLEGE CORNER	138.00	138.00	3	51.90		2
16	0625 TANNERS CREEK	COLLEGE CORNER	138.00	138.00	1	0.37		2
17	0626 COLLEGE CORNER	RANDOLPH	138.00	138.00	2	34.58		1
18	0626 COLLEGE CORNER	RANDOLPH	138.00	138.00	1	1.07		1
19	0626 COLLEGE CORNER	RANDOLPH	138.00	138.00	2	3.34		
20	0627 RANDOLPH	JAY	138.00	138.00	2	23.69		1
21	0627 RANDOLPH	JAY	138.00	138.00	1	0.32		
22	0628 MCKINLEY TAP		138.00	138.00	3	1.00		2
23	0629 JAY	LINCOLN	138.00	138.00	2	46.18		1
24	0629 JAY	LINCOLN	138.00	138.00	3	3.11		1
25	0630 NEW CARLISLE	MAPLE	138.00	138.00	2	1.00		1
26	6104 SORENSON	TWIN BRANCH	138.00	138.00	3	61.17		1
27	6104 SORENSON	TWIN BRANCH	138.00	138.00	1	0.31		1
28	6104 SORENSON	TWIN BRANCH	138.00	138.00	1	3.32		1
29	0632 SORENSON	DEVILS HOLLOW	138.00	138.00	3			
30	0634 DEER CREEK	MULLIN	138.00	138.00	2	15.70		1
31	0635 PENDLETON	MULLIN	138.00	138.00	2	14.10		1
32	0635 PENDLETON	MULLIN	138.00	138.00	3	0.40		1
33	0635 PENDLETON	MULLIN	138.00	138.00	1	0.72		1
34	0636 DEER CREEK	FISHER BODY	138.00	138.00	3	5.04		2
35	0637 TWIN BRANCH	EAST ELKHART	138.00	138.00	3	17.00	1.00	2
36					TOTAL	3,758.80	112.28	271

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TRANSMISSION LINE STATISTICS (Continued)

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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)	
397.5 KCM								1
397.5 KCM								2
397.5 KCM								3
2,000KCM								4
397.5 KCM								5
397.5 KCM								6
795 KCM								7
397.5 KCM								8
795 KCM								9
636 KCM								10
556.5 KCM								11
556.5 KCM								12
477 KCM								13
795 KCM								14
636 KCM								15
636 KCM								16
556.5 KCM								17
556.5 KCM								18
556.5 KCM								19
556.5 KCM								20
556.5 KCM								21
300 KCM CU								22
556.5 KCM								23
1033.5 KCM								24
397.5 KCM								25
447 KCM								26
556.5 KCM								27
556.5 KCM								28
556.5 KCM								29
556.5 KCM								30
556.5 KCM								31
556.5 KCM								32
556.5 KCM								33
397.5 KCM								34
556.5 KCM								35
	69,585,869	693,760,138	763,346,007	340,378	12,724,083		13,064,461	36

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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	0638 GRANT	FISHER BODY	138.00	138.00	3		1.00	1
2	0639 ROBISON PARK	AUBURN	138.00	138.00	1			1
3	0641 DESOTO	MEDFORD	138.00	138.00	3	7.00		2
4	0642 OLIVE	HICKORY CREEK	138.00	138.00	3	2.99	2.00	1
5	0645 COREY TAP		138.00	138.00	2	4.00		1
6	0646 OLIVE	NEW CARLISLE	138.00	138.00	3	2.00		1
7	0647 OLIVE	SOUTH BEND	138.00	138.00	3	15.97		2
8	0647 OLIVE	SOUTH BEND	138.00	138.00	3	1.00		2
9	0648 MEDFORD TAP		138.00	138.00	3	8.00		2
10	0723 SPY RUN STATION		138.00	138.00	4			1
11	6101 WESTINGHOUSE TAP		138.00	138.00	3	2.00		2
12	6102 MILAN TAP		138.00	138.00	3	6.00		2
13	6103 MILAN	GOODRICH	138.00	138.00	3	1.00		2
14	6105 DESOTO	JAY	138.00	138.00	2	10.31		1
15	6105 DESOTO	JAY	138.00	138.00	3	2.25		1
16	6106 DESOTO	DEER CREEK-DELAWARE	138.00	138.00	3	7.52		2
17	6106 DESOTO	DEER CREEK-DELAWARE	138.00	138.00	1	0.48		
18	6107 DARDEN TAP		138.00	138.00	2	1.00		1
19	6109 ROBISON PARK	RICHLAND	138.00	138.00	2	13.76		1
20	6109 ROBISON PARK	RICHLAND	138.00	138.00	1	0.05		
21	6109 ROBISON PARK	RICHLAND	138.00	138.00	3	4.49		
22	6110 WESTINGHOUSE	23RD STREET	138.00	138.00	3			2
23	6111 KANKAKEE	WEST SIDE	138.00	138.00	1	2.00		1
24	6113 INDUSTRIAL PARK		138.00	138.00	3	3.00		2
25	6114 OLIVE	MICHIGAN CITY	138.00	138.00	3	2.00	1.00	1
26	6115 HUMMEL CREEK	VAN BUREN	138.00	138.00	3	6.00		2
27	6130 HUMMEL CREEK	TOWER 70, GREENTOWN	138.00	138.00				
28	6116 SOUTH ELWOOD TAP		138.00	138.00	1	3.07		1
29	6117 PENDLETON	FALL CREEK	138.00	138.00	3	10.70		2
30	6117 PENDLETON	FALL CREEK	138.00	138.00	1	0.07		2
31	6121 ROBISON PARK	LINCOLN	138.00	138.00	3	7.84		1
32	6121 ROBISON PARK	LINCOLN	138.00	138.00	1	0.02		
33	6126 CONCORD	EAST ELKHART	138.00	138.00	3	11.00		1
34	6129 GREENTOWN-GRANT	HUMMEL CREEK	138.00	138.00	3	21.00		1
35	6131 INDUSTRIAL PARK	MC KINLEY	138.00	138.00	1	5.00		1
36					TOTAL	3,758.80	112.28	271

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397.5 KCM								1
556.5 KCM								2
556.5 KCM								3
556.5 KCM								4
477 KCM								5
556.5 KCM								6
397.5 KCM								7
556.5 KCM								8
556.5 KCM								9
3.5IN OD								10
556.5 KCM								11
397.5 KCM								12
397.5 KCM								13
2-556.5 KCM								14
2-556.5 KCM								15
636 KCM								16
636 KCM								17
336.4 KCM								18
636 KCM								19
1233.6 KCM								20
636 KCM								21
556.5 KCM								22
636 KCM								23
745 KCM								24
636 KCM								25
795 KCM								26
								27
556.5 KCM								28
795 KCM								29
795 KCM								30
795 KCM								31
1233.6 KCM								32
795 KCM								33
795 KCM								34
795 KCM								35
	69,585,869	693,760,138	763,346,007	340,378	12,724,083		13,064,461	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 2018/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	6132 CROSS STREET TAP	JUNCTION TOWER #88	138.00	138.00	1	4.00		1
2	6134 LINCOLN	ANTHONY	138.00	138.00	1	3.00		1
3	6135 WAYNEDALE TAP		138.00	138.00	3			2
4	6138 JACKSON ROAD	SOUTH SIDE	138.00	138.00	1	2.00		1
5	6142 ALBION	KENDALLVILLE	138.00	138.00	1	10.00		1
6	6150 SOUTHSIDE	SOUTH BEND	138.00	138.00	1	6.07		1
7	6219 DELCO BATTERY TAP		138.00	138.00	1	1.00		2
8	6220 FALL CREEK	MADISON-NEW CASTLE	138.00	138.00	3	1.10		2
9	6220 FALL CREEK	MADISON-NEW CASTLE	138.00	138.00	1	0.15		2
10	6225 INDUSTRIAL PARK	SPY RUN	138.00	138.00	1	4.00		1
11	6266 WALLEN		138.00	138.00	1	0.22		1
12	6234 CABOT TAP/CR 4	EAST ELKHART	138.00	138.00	1	0.13		1
13	6238 SORENSON	MCKINLEYTOWER	138.00	138.00	3	2.82		2
14	6238 SORENSON	MCKINLEYTOWER	138.00	138.00	1	0.26		2
15	6241 KENDALLVILLE TAP	CITY OF AUBURN #5	138.00	138.00	1,2	14.00		1
16	6242 AUBURN	CITY OF AUBURN #5	138.00	138.00	1	2.00		1
17	6245 LAPORTE JCT	LIQUID CARBONICS	138.00	138.00	1	4.76		1
18	6245 LAPORTE JCT	LIQUID CARBONICS	138.00	138.00	1	0.23		
19	6246 LAPORTE JCT	AIRCO	138.00	138.00	1	0.72		1
20	6248 ELCONA TAP	CONC-DUN-E-ELK	138.00	138.00	1	2.00		1
21	6249 ALLEN	LINCOLN	138.00	138.00	3	4.90		2
22	6249 ALLEN	LINCOLN	138.00	138.00	1	0.09		2
23	6250 ALLEN	ADAMS/HILLCREST	138.00	138.00	3	4.92		2
24	6250 ALLEN	ADAMS/HILLCREST	138.00	138.00	1	0.07		2
25	6251 OLIVE	EDISON	138.00	138.00	3	1.00		2
26	6253 TRIER RD TAP		138.00	138.00	1			1
27	6258 KENZIE CREEK	TWIN BRANCH	138.00	138.00	3			2
28	6260 WILMINGTON TAP		138.00	138.00	1	1.00	9.00	1
29	6229 DUNLAP NORTH TAP		34.00	138.00	1	2.00		2
30	6140 INDIANA-PURDUE		34.00	138.00	1			2
31	6217 HILLCREST	KINNERK	69.00	138.00	1	3.92		1
32	6217 HILLCREST	KINNERK	69.00	138.00	2	0.03		1
33	6252 KENDALLVILLE	BIXLER	138.00	138.00	1	2.91		1
34	6254 ALLEN/LINCOLN	ALLEN/HILLCREST	138.00	138.00				
35	6265 CONCORD	WOLF	138.00	138.00	1	0.56	0.54	1
36					TOTAL	3,758.80	112.28	271

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)			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)	
795 KCM								1
795 KCM								2
795 KCM								3
795 KCM								4
795 KCM								5
795 KCM								6
795 KCM AA								7
795 KCM								8
795 KCM								9
1033 KCM								10
1033.5 KCM								11
556.5 KCM								12
795 KCM								13
795 KCM								14
795 KCM								15
795 KCM								16
795 KCM								17
1033.5 KCM								18
795 KCM								19
795 KCM								20
1033 KCM								21
1233.6 KCM								22
1033 KCM								23
1233.6 KCM								24
795 KCM								25
795 KCM								26
1033 KCM								27
2-954 KCM								28
795 KCM								29
1033 KCM								30
795 KCM								31
795 KCM								32
795 KCM								33
								34
336.4 ACSR KCM								35
	69,585,869	693,760,138	763,346,007	340,378	12,724,083		13,064,461	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 2018/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	6271 INDALEX TAP/CR 4	EAST ELKHART	138.00	138.00	1	1.09		
2	6267 STUDEBAKER	WEST SIDE	138.00	138.00	1	2.57		1
3	6270 JONES CREEK	HOGAN	138.00	138.00		5.62		
4	6273 DAWKINS SWITCH	HERBERT MONROE (WVPA)	138.00	138.00	1	0.50		1
5								
6	LINES<132 KV	SYSTEM	69.00		Various	757.31	72.00	1
7								
8	STATE OF MICHIGAN							
9	6216 D.C. COOK	DUMONT	765.00	765.00	3	16.00		1
10	6120 COOK	PALISADES	345.00	345.00	3	41.78		2
11	6120 COOK	PALISADES	345.00	345.00	1	0.23		
12	6120 COOK	PALISADES	345.00	345.00	1	0.21		
13	6143 D.C. COOK	OLIVE-PALISADES	345.00	345.00	3	5.00		2
14	6144 TWIN BRANCH	COOK-ROB PARK JCT	345.00	345.00	3			2
15	6151 COOK	OLIVE	345.00	345.00				
16	6152 COOK	ROBISON PARK	345.00	345.00				
17	6146 D.C. COOK	ROBISON PARK	345.00	345.00	3	37.00		2
18	6146 D.C. COOK	ROBISON PARK	345.00	345.00	3	0.09		
19	6214 COOK-ROB PARK	ARGENTA	345.00	345.00	3	28.78		2
20	6214 COOK-ROB PARK	ARGENTA	345.00	345.00	1	0.22		2
21	6221 D.C. COOK	OLIVE-PALISADES	345.00	345.00	3	5.00		2
22	6263 BARODA TAP		138.00	138.00				
23	0601 TWIN BRANCH	RIVERSIDE	138.00	138.00	3	33.90		2
24	0601 TWIN BRANCH	RIVERSIDE	138.00	138.00	1	0.10		2
25	0610 AUTO SPECIALTIES		138.00	138.00				
26	0621 TWIN BRANCH - R	HICKORY CREEK	138.00	138.00	3	5.00		2
27	0644 RIVERSIDE	HARTFORD	138.00	138.00	2	14.22		1
28	0644 RIVERSIDE	HARTFORD	138.00	138.00	3	2.11		
29	0649 COREY TAP		138.00	138.00	2	12.12		1
30	0649 COREY TAP		138.00	138.00	1	0.13		1
31	6108 RIVERSIDE	OLIVE-HICKORY CREEK	138.00	138.00	1	6.00		1
32	6124 BENTON HARBOR	RIVERSIDE-HARTFORD	138.00	138.00	3	1.00		2
33	6137 EDGEWATER TAP		138.00	138.00	1	0.76		1
34	6139 BENTON HARBOR	TWIN BRANCH-R SIDE	138.00	138.00	3	6.00		2
35	6149 HARTFORD	COREY	138.00	138.00	1	18.97		1
36					TOTAL	3,758.80	112.28	271

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 2018/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
954 KCM								2
								3
4/0								4
								5
VARIOUS								6
								7
								8
4-954 KCM								9
2-954 KCM								10
2-954 KCM								11
2-1158.4 KCM								12
2-954 KCM								13
2-954 KCM								14
								15
								16
2-954 KCM								17
954 KCM								18
2-954 KCM								19
2-954 KCM								20
2-954 KCM								21
								22
397.5KCM & 1033.5								23
397.5KCM & 1033.5								24
								25
397.5 KCM								26
397.5 KCM								27
397.5 KCM								28
477 KCM								29
477 KCM								30
636 KCM								31
795 KCM								32
556.5 KCM								33
795 KCM								34
795 KCM								35
	69,585,869	693,760,138	763,346,007	340,378	12,724,083		13,064,461	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 2018/Q4

TRANSMISSION LINE STATISTICS

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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	6149 HARTFORD	COREY	138.00	138.00			2.11	1
2	6149 HARTFORD	COREY	138.00	138.00	2	12.88		1
3	6149 HARTFORD	COREY	138.00	138.00			0.98	1
4	6149 HARTFORD	COREY	138.00	138.00	1	1.34		1
5	6149 HARTFORD	COREY	138.00	138.00	1	0.53		2
6	6218 MOTTVILLE TAP		138.00	138.00	1	1.00		1
7	6255 KENZIE CREEK	VALLEY	138.00	138.00	1	20.00		1
8	6257 KENZIE CREEK	T B/R'SIDE/HICK CR	138.00	138.00	3			
9	6261 FLATBUSH TAP		138.00	138.00		1.00		1
10	6262 WEST ST TAP		138.00	138.00		1.00		2
11	6700 GM HYDRAMATIC		138.00	138.00	3	2.00		2
12	6227 NICKERSON	TOWER #13A	138.00	138.00				
13	0643 OLIVE	HICKORY CREEK	138.00	138.00	3	22.80	2.00	1
14	6268 SAUK TRAIL		138.00	138.00	1	1.60		
15								
16	LESS THAN 132 KV LINES		69.00		Various	401.00	12.00	
17								
18	Line cost and expense are	not available by individual						
19	transmission line.	Total shown in column j-p						
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	3,758.80	112.28	271

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 2018/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.
795 KCM								1
795 KCM								2
1033.5 KCM								3
1033.5 KCM								4
1033.5 KCM								5
795 AA								6
1033 KCM								7
795 KCM								8
								9
								10
795 KCM								11
								12
556.5 KCM								13
1033.5KCM								14
								15
VARIOUS								16
								17
	69,585,869	693,760,138	763,346,007	340,378	12,724,083		13,064,461	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	69,585,869	693,760,138	763,346,007	340,378	12,724,083		13,064,461	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 2018/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							
16							
17							
18							
19							
20							
21							
22							
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26							
27							
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30							
31							
32							
33							
34							
35							
36							
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
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		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
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
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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 2018/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	69.00	34.00
2	ADAMS (IM) - IN	T	138.00	13.00	
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	ALLEN (IM) - IN	T	345.00	137.50	13.80
9	AM GENERAL #1 - IN	D	34.50	4.00	
10	ANACONDA - IN	D	34.50	4.00	
11	ANCHOR HOCKING (IM) - IN	D	69.00	13.09	
12	ANCHOR HOCKING (IM) - IN	D	69.00	2.40	
13	ANTHONY - IN	T	138.00	34.00	
14	ANTHONY - IN	T	34.50	12.00	
15	ANTIVILLE - IN	D	69.00	12.00	
16	ARMSTRONG CORK - IN	D	69.00	4.00	
17	ARNOLD HOGAN - IN	T	138.00	13.09	
18	ARNOLD HOGAN - IN	T	34.50		
19	AUBURN - IN	T	138.00		
20	AUBURN - IN	T	138.00	70.50	36.20
21	BARLEY - IN	D	34.50	13.00	
22	BEECH ROAD - IN	D	138.00	13.09	
23	BERNE - IN	D	69.00	12.00	
24	BERNE - IN	D	69.00		
25	BETHEL - IN	D	34.50	13.00	
26	BIG RUN - IN	T	69.00	0.48	
27	BIXLER - IN	D	138.00	13.09	
28	BLAINE STREET - IN	D	34.50	13.00	
29	BLUFF POINT - IN	T	69.00	13.00	
30	BLUFF POINT - IN	T	69.00		
31	BLUFFTON (IM) - IN	T	69.00		
32	BOSMAN - IN	D	34.50	13.00	
33	BUTLER (IM) - IN	D	69.00	13.00	
34	BUTLER (IM) - IN	D	69.00		
35	CALVERT - IN	D	138.00	13.09	
36	CAPITAL AVENUE - IN	T	138.00	13.09	
37	CARROLL - IN	D	34.50	13.00	
38	CHARLES - IN	D	34.50	13.00	
39	CHURUBUSCO - IN	D	34.50	13.00	
40	CHURUBUSCO - IN	D	34.50		

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 2018/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.
115	1					1
13	1					2
9	1					3
8	1					4
90	1					5
			STATCAP	1	53	6
			STATCAP	1	14	7
450	1					8
7	2					9
4	1					10
20	1					11
14	2					12
112	1					13
29	2					14
4	1					15
20	2					16
22	1					17
			STATCAP	1	14	18
			STATCAP	2	106	19
130	1					20
2	1					21
20	1					22
20	1					23
			STATCAP	1	16	24
11	1					25
3	1					26
20	1					27
29	2					28
6	1					29
			STATCAP	1	16	30
			STATCAP	1	16	31
9	1					32
20	1					33
			STATCAP	2	30	34
20	1					35
12	1					36
2	3					37
2	1					38
11	1					39
			STATCAP	1	5	40

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	CLEVELAND - IN	D	138.00	13.09	
2	CLIPPER - IN	D	69.00	13.09	
3	COLFAX - IN	D	34.50	12.00	
4	COLONY BAY - IN	D	69.00	12.00	
5	COLONY BAY - IN	D	69.00	13.00	
6	COLUMBIA(IM) - IN	T	138.00	69.00	34.00
7	CONANT - IN	D	34.50	12.00	
8	CONCORD - IN	T	138.00	13.09	
9	CONCORD - IN	T	138.00	13.09	
10	CONCORD - IN	T	138.00		
11	COUNTRYSIDE - IN	D	138.00	12.47	
12	COUNTY LINE (IM) - IN	D	138.00	13.09	
13	COUNTY ROAD 4 - IN	D	138.00	13.09	
14	CROSS STREET - IN	D	138.00	13.09	
15	DALEVILLE - IN	D	138.00	13.09	
16	DARDEN ROAD - IN	D	138.00	13.09	
17	DECATUR (FTW) - IN	T	69.00	4.00	
18	DECATUR (FTW) - IN	T	69.00	13.00	
19	DECATUR (FTW) - IN	T	69.00		
20	DEER CREEK - IN	T	138.00		
21	DEER CREEK - IN	T	34.50		
22	DEER CREEK - IN	T	138.00	13.09	
23	DEER CREEK - IN	T	138.00	34.50	
24	DEER CREEK - IN	T	138.00	69.00	34.00
25	DEER CREEK - IN	T	34.50	13.09	
26	DELAWARE (IM) - IN	T	138.00	34.00	
27	DELAWARE (IM) - IN	T	138.00		
28	DELAWARE (IM) - IN	T	34.50		
29	DESOTO - IN	T	345.00	138.00	34.50
30	DIEBOLD ROAD - IN	D	69.00	13.00	
31	DOOVILLE - IN	D	138.00	13.09	
32	DRAGOON - IN	T	138.00	69.00	34.00
33	DRAGOON - IN	T	34.50		
34	DREWRYS - IN	D	34.50	12.00	
35	DREWRYS - IN	D	34.50	13.09	
36	DUMONT - IN	T	765.00		
37	DUNLAP - IN	T	138.00	13.09	
38	DUNLAP - IN	T	138.00	69.00	34.00
39	DUNLAP - IN	T	138.00	13.09	
40	EAST ELKHART - IN	T	138.00	69.00	34.00

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
6	1					2
22	1					3
20	1					4
22	1					5
50	1					6
22	1					7
22	1					8
22	1					9
			STATCAP	1	53	10
20	1					11
20	1					12
20	1					13
20	1					14
20	1					15
42	2					16
5	1					17
20	1					18
			STATCAP	1	13	19
			STATCAP	1	58	20
			STATCAP	2	30	21
20	1					22
75	1					23
90	1					24
4	1					25
125	2					26
			STATCAP	1	53	27
			STATCAP	1	5	28
675	1					29
20	1					30
12	1					31
84	1					32
			STATCAP	1	12	33
8	1					34
8	1					35
			REACTOR	2	200	36
20	1					37
130	1					38
20	1					39
84	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 2018/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	EAST ELKHART - IN	T	345.00	137.50	13.80
2	EAST ELKHART - IN	T	34.50	7.20	
3	EAST SIDE (IM) - IN	D	138.00	13.09	
4	EGE - IN	D	138.00	34.50	13.00
5	ELCONA - IN	D	138.00	13.09	
6	ELKHART HYDRO STAT - IN	T	34.50	13.00	
7	ELKHART HYDRO STAT - IN	T	34.50		
8	ELLISON ROAD - IN	T	138.00	13.09	
9	ELMRIDGE - IN	D	34.50	13.00	
10	ELWOOD (IM) - IN	D	34.50	13.00	
11	ELWOOD (IM) - IN	D	34.50		
12	FAIRMOUNT - IN	D	34.50	7.20	
13	FARMLAND - IN	D	69.00	13.09	
14	FERGUSON - IN	D	69.00	13.00	
15	FISHER BODY - IN	D	138.00	13.80	
16	FULTON (IM) - IN	D	34.50	13.00	
17	GAS CITY - IN	D	34.50	13.00	
18	GAS CITY - IN	D	34.50		
19	GASTON - IN	D	138.00	13.09	
20	GATEWAY (IM) - IN	T	69.00	34.00	
21	GATEWAY (IM) - IN	T	69.00		
22	GERMAN - IN	D	138.00	13.09	
23	GLENBROOK - IN	D	34.50	13.00	
24	GRABILL - IN	D	138.00	13.09	
25	GRANGER - IN	D	138.00	12.47	
26	GRANGER - IN	D	138.00	13.09	
27	GRANT - IN	T	138.00	13.09	
28	GRANT - IN	T	138.00	34.50	
29	GREENLEAF - IN	D	34.50	13.09	
30	GREENTOWN - IN	T	765.00		
31	HACIENDA - IN	D	138.00	13.09	
32	HACIENDA - IN	D	138.00	13.09	
33	HADLEY - IN	D	69.00	13.00	
34	HAMILTON - IN	D	69.00	13.00	
35	HARLAN - IN	D	69.00	13.09	
36	HARPER - IN	D	138.00	13.09	
37	HARRISON STREET - IN	D	34.50	4.00	
38	HARTFORD CITY - IN	T	69.00	13.00	
39	HARTFORD CITY - IN	T	69.00	34.00	
40	HARVEST PARK - IN	D	34.50	13.00	

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 2018/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.
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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)	
450	1					1
1		1				2
37	2					3
8	1					4
22	1					5
8	1					6
			STATCAP	1	14	7
20	1					8
9	1					9
19	2					10
			STATCAP	1	5	11
11	1					12
20	1					13
20	1					14
100	2					15
20	1					16
20	1					17
			STATCAP	1	10	18
20	1					19
20	1					20
			STATCAP	1	13	21
47	2					22
40	2					23
20	1					24
20	1					25
20	1					26
20	1					27
30	1					28
20	1					29
			REACTOR	1	100	30
20	1					31
25	1					32
40	2					33
11	1					34
13	1					35
20	1					36
4	1					37
20	1					38
20	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 2018/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	HILLCREST - IN	T	138.00	13.09	
2	HILLCREST - IN	T	138.00		
3	HUMMEL CREEK - IN	T	138.00	13.09	
4	HUMMEL CREEK - IN	T	138.00	69.00	34.00
5	ILLINOIS ROAD - IN	T	138.00	69.00	13.00
6	ILLINOIS ROAD - IN	T	138.00	13.09	
7	INDUSTRIAL PARK - IN	T	138.00	13.09	
8	INDUSTRIAL PARK - IN	T	34.50	13.00	
9	INDUSTRIAL PARK - IN	T	138.00	69.00	34.00
10	INDUSTRIAL PARK - IN	T	138.00		
11	IRELAND ROAD - IN	D	138.00	13.09	
12	IU PURDUE - IN	D	13.80	4.00	
13	JACKSON ROAD - IN	T	138.00	13.09	
14	JACKSON ROAD - IN	T	138.00	34.00	
15	JACKSON ROAD - IN	T	345.00	138.00	34.00
16	JAY (IM) - IN	T	138.00	69.00	34.00
17	JAY (IM) - IN	T	138.00	13.09	
18	JAY (IM) - IN	T	138.00		
19	JEFFERSON (IM) - IN	T	138.00		
20	JEFFERSON (IM) - IN	T	765.00		
21	JOBES - IN	D	34.50	4.00	
22	JONES CREEK - IN	D	138.00	12.47	
23	KANKAKEE - IN	T	138.00	13.09	
24	KENDALLVILLE - IN	T	69.00	12.00	
25	KENDALLVILLE - IN	T	69.00	13.00	
26	KENDALLVILLE - IN	T	138.00	69.00	13.00
27	KENDALLVILLE - IN	T	138.00		
28	KINGSLAND - IN	D	69.00	13.00	
29	KLINE - IN	T	138.00	34.00	
30	KLINE - IN	T	34.50		
31	LANTERN PARK - IN	D	138.00	13.09	
32	LAPAZ - IN	D	34.50	13.00	
33	LAPORTE JUNCTION - IN	T	138.00	69.00	34.00
34	LIGONIER - IN	D	138.00	13.09	
35	LINCOLN - IN	T	138.00	36.20	
36	LINCOLN - IN	T	138.00	70.50	36.20
37	LINCOLN - IN	T	138.00	13.09	
38	LINCOLN - IN	T	138.00		
39	LINWOOD (IM) - IN	D	138.00	13.09	
40	LOBDELL - IN	D	69.00	0.48	

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.
22	1					1
			STATCAP	1	53	2
20	1					3
75	1					4
84	1					5
20	1					6
22	1					7
22	1					8
75	1					9
			STATCAP	1	50	10
20	1					11
5	1					12
32	2					13
30	1					14
672	1					15
115	1					16
9	1					17
			STATCAP	1	58	18
			REACTOR	1	20	19
			REACTOR	7	550	20
9	1					21
20	1					22
22	1					23
11	1					24
8	1					25
75	1					26
			STATCAP	1	43	27
5	1					28
100	1					29
			STATCAP	1	14	30
20	1					31
5	1					32
84	1					33
29	2					34
75	1					35
200	1					36
20	1					37
			STATCAP	1	53	38
11	1					39
3	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 2018/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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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	LYDICK - IN	D	34.50	13.09	
2	LYNN - IN	D	69.00	13.00	
3	MADISON (IM) - IN	T	34.50	13.09	
4	MADISON (IM) - IN	T	138.00	35.00	
5	MAGLEY - IN	T	138.00	69.00	13.00
6	MAGLEY - IN	T	69.00	13.00	
7	MARION ETHANOL - IN	D	34.50	4.00	
8	MARION PLANT - IN	D	34.50	4.00	
9	MARION PLANT - IN	D	34.50	13.00	
10	MARION PLANT - IN	D	34.50		
11	MAYFIELD - IN	D	138.00	13.09	
12	MCCLURE - IN	D	34.50	4.00	
13	MCGALLIARD ROAD - IN	D	34.50	13.00	
14	MCKINLEY - IN	T	138.00	13.09	
15	MCKINLEY - IN	T	138.00	34.00	
16	MCKINLEY - IN	T	138.00	70.50	36.20
17	MCKINLEY - IN	T	138.00		
18	MCKINLEY - IN	T	69.00		
19	MEADOW LAKE SW - IN	T	345.00		
20	MEADOWBROOK - IN	T	34.50		
21	MEADOWBROOK - IN	T	138.00	35.00	
22	MEDFORD - IN	T	138.00	69.00	34.00
23	MEDFORD - IN	T	34.50		
24	MIDDLEBURY - IN	D	34.50	0.48	
25	MIER - IN	D	138.00	13.09	
26	MILLER AVENUE - IN	D	34.50	4.00	
27	MISSISSINEWA - IN	D	138.00	13.09	
28	MOCK AVENUE - IN	D	34.50	4.00	
29	MODOC - IN	T	69.00	13.00	
30	MODOC - IN	T	138.00	69.00	13.00
31	MONROE (IM) - IN	D	69.00	13.00	
32	MURRAY - IN	D	69.00	13.00	
33	NEW CARLISLE - IN	T	138.00	34.50	
34	NORTH KENDALLVILLE - IN	D	69.00	12.00	
35	NORTH PORTLAND - IN	D	69.00	13.00	
36	NORTHLAND - IN	D	138.00	13.09	
37	NORTHWEST ELKHART - IN	D	34.50	12.00	
38	NORTHWEST ELKHART - IN	D	34.50	13.00	
39	NORTHWEST ELKHART - IN	D	34.50		
40	OHIO OIL - IN	D	34.50	13.00	

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
7	1					2
5	1					3
60	1					4
90	1					5
9	1					6
11	1					7
6	1					8
22	1					9
			STATCAP	1	9	10
20	1					11
8	1					12
29	2					13
40	2					14
112	1					15
130	1					16
			STATCAP	1	86	17
			STATCAP	1	22	18
			STATCAP	2		19
			STATCAP	2	29	20
100	1					21
75	1					22
			STATCAP	1	15	23
3	1					24
11	1					25
8	1					26
12	1					27
4	1					28
5	1					29
60	1					30
8	1					31
5	1					32
30	1					33
22	1					34
20	1					35
32	2					36
11	1					37
20	1					38
			STATCAP	1	14	39
6	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 2018/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	OLIVE - IN	T	138.00	13.09	
2	OLIVE - IN	T	138.00	69.00	34.00
3	OLIVE - IN	T	345.00	138.00	34.50
4	OSOLO - IN	T	138.00	69.00	34.00
5	OSOLO - IN	T	138.00	13.09	
6	OSOLO - IN	T	34.50		
7	OSSIAN - IN	D	69.00	13.00	
8	PARKWAY - IN	D	34.50	13.00	
9	PARNELL - IN	D	34.50	13.00	
10	PARNELL - IN	D	34.50	13.09	
11	PEACOCK - IN	D	34.50	13.00	
12	PENDLETON - IN	T	138.00	35.00	
13	PENNVILLE - IN	D	138.00	34.00	13.00
14	PHILIPS - IN	D	69.00	0.48	
15	PINE ROAD - IN	D	138.00	13.09	
16	PIPE CREEK - IN	D	138.00	12.00	
17	PLEASANT - IN	D	69.00	13.00	
18	PLEASANT - IN	D	69.00		
19	PORTLAND (IM) - IN	D	69.00	13.00	
20	PRICE - IN	D	69.00	13.09	
21	RANDOLPH - IN	T	138.00	13.09	
22	RANDOLPH - IN	T	138.00	69.00	13.00
23	RANDOLPH - IN	T	34.50	12.00	
24	RANDOLPH - IN	T	69.00		
25	REED - IN	D	138.00	13.09	
26	RENNER STREET - IN	D	69.00	0.48	
27	ROBISON PARK - IN	T	138.00		
28	ROBISON PARK - IN	T	138.00	13.09	
29	ROBISON PARK - IN	T	138.00	70.50	36.20
30	ROBISON PARK - IN	T	138.00	13.09	
31	ROCKPORT - IN	T	34.50	13.00	
32	ROCKPORT - IN	T	765.00		
33	ROCKPORT - IN	T	138.00		
34	ROSE HILL - IN	D	138.00	13.00	
35	ROYERTON - IN	D	138.00	13.09	
36	SATURN - IN	T	138.00	13.09	
37	SELMA PARKER - IN	T	138.00	13.09	
38	SHARON ROAD - IN	D	34.50	13.00	
39	SILVER LAKE - IN	D	34.50	12.00	
40	SORENSON - IN	T	138.00	13.09	

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 2018/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.
9	1					1
27	1					2
675	1					3
75	1					4
20	1					5
			STATCAP	1	14	6
20	1					7
5	1					8
20	1					9
20	1					10
5	1					11
75	1					12
8	1					13
3	1					14
20	1					15
20	1					16
5	1					17
			STATCAP	1	13	18
17	2					19
20	1					20
22	1					21
56	1					22
4	1					23
			STATCAP	1	14	24
22	1					25
3		1				26
			STATCAP	1	86	27
25	1					28
90	1					29
20	1					30
2	2					31
			REACTOR	4	200	32
			REACTOR	1	20	33
8	1					34
11	1					35
13	1					36
	1					37
2	3					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 2018/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	SORENSON - IN	T	345.00	138.00	34.00
2	SORENSON - IN	T	345.00	138.00	34.50
3	SORENSON - IN	T	765.00	345.00	34.50
4	SORENSON - IN	T	765.00	345.00	34.50
5	SORENSON - IN	T	765.00	345.00	34.50
6	SOUTH BEND - IN	T	138.00		
7	SOUTH BEND - IN	T	138.00	34.00	
8	SOUTH BEND - IN	T	138.00	69.00	34.00
9	SOUTH BEND - IN	T	138.00	13.09	
10	SOUTH BERNE - IN	D	69.00	12.00	
11	SOUTH DECATUR - IN	D	69.00	13.00	
12	SOUTH DECATUR - IN	D	69.00	13.09	
13	SOUTH ELWOOD - IN	T	138.00	13.09	
14	SOUTH ELWOOD - IN	T	138.00	34.00	
15	SOUTH SIDE (MARION) - IN	D	34.50	13.09	
16	SOUTH SIDE (SOUTH BEND) - IN	D	138.00	13.09	
17	SOUTH SUMMITVILLE - IN	T	34.50	13.09	
18	SOYA - IN	D	34.50	4.00	
19	SPRING STREET - IN	D	34.50	12.00	
20	SPRING STREET - IN	D	34.50	13.00	
21	SPRINGVILLE - IN	D	69.00	13.00	
22	SPY RUN 34 - IN	D	34.50	12.00	
23	SPY RUN SF6 - IN	T	138.00	13.09	
24	SPY RUN SF6 - IN	T	138.00	34.00	
25	ST MARYS COLLEGE - IN	D	34.50	4.33	
26	ST. JOE - IN	D	69.00	13.09	
27	STATE STREET - IN	D	138.00	13.09	
28	STUDEBAKER - IN	D	138.00	13.09	
29	STUDEBAKER - IN	D	138.00	13.80	
30	SULLIVAN (IM) - IN	T	138.00		
31	SULLIVAN (IM) - IN	T	765.00		
32	SUMMIT - IN	D	138.00	13.09	
33	SWANSON - IN	D	69.00	34.00	
34	SWANSON - IN	D	69.00		
35	THOMAS ROAD - IN	D	69.00	13.09	
36	THREE M - IN	D	69.00	4.00	
37	THREE RIVERS (FTW) - IN	D	34.50	13.00	
38	TILLMAN - IN	T	138.00	13.09	
39	TILLMAN - IN	T	138.00	36.20	
40	TILLOTSON - IN	D	34.50	13.00	

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 2018/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)	
675	1					1
675	1					2
		1				3
		1				4
		1				5
			STATCAP	1	53	6
150	2					7
130	1					8
20	1					9
12	1					10
20	1					11
20	1					12
20	1					13
30	1					14
20	1					15
20	1					16
20	1					17
11	1					18
12	1					19
8	1					20
9	1					21
20	1					22
22	1					23
200	2					24
8	1					25
20	1					26
22	1					27
20	1					28
36	2					29
			REACTOR	1	20	30
			REACTOR	4	200	31
40	2					32
45	2					33
			STATCAP	1	14	34
20	1					35
13	1					36
10	2					37
	1					38
18	1					39
20	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 2018/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	TORRINGTON - IN	D	34.50	4.00	
2	TRIER - IN	D	138.00	13.09	
3	TRI-LAKES - IN	D	69.00	13.00	
4	TWENTY FIRST STREET - IN	D	34.50	13.00	
5	TWENTY THIRD STREET (IM) - IN	T	138.00	69.00	34.00
6	TWENTY THIRD STREET (IM) - IN	T	34.50		
7	TWIN BRANCH 138KV - IN	T	138.00	13.09	
8	TWIN BRANCH 345KV - IN	T	345.00	137.50	13.20
9	TWIN BRANCH 345KV - IN	T	345.00	138.00	34.50
10	TWIN BRANCH 34KV - IN	T	34.50	13.00	
11	TWIN BRANCH 34KV - IN	T	34.50		
12	UNIVERSAL TOOL - IN	D	69.00	0.48	
13	UP RIVER DAM - IN	D	13.80	4.00	
14	UP RIVER DAM - IN	D	34.50	4.00	
15	UPLAND - IN	D	69.00	13.20	
16	UTICA (IM) - IN	D	34.50	13.09	
17	VAN BUREN - IN	T	138.00	69.00	13.00
18	WABASH AVENUE - IN	D	69.00	13.09	
19	WALLEN - IN	T	138.00	69.00	34.00
20	WALLEN - IN	T	138.00	13.09	
21	WARREN - IN	D	69.00	12.00	
22	WATER POLLUTION - IN	D	34.50	4.00	
23	WAYNE TRACE - IN	D	138.00	13.09	
24	WAYNEDALE - IN	D	138.00	12.47	
25	WAYNEDALE - IN	D	138.00	13.09	
26	WES-DEL - IN	D	138.00	13.09	
27	WEST END - IN	D	34.50	13.00	
28	WEST END - IN	D	34.50	4.00	
29	WEST END - IN	D	34.50	13.00	
30	WEST SIDE - IN	T	138.00	13.09	
31	WEST SIDE - IN	T	138.00	69.00	34.00
32	WHITAKER - IN	D	34.50	12.00	
33	WHITLEY SW - IN	T	34.50		
34	WINCHESTER (IM) - IN	T	69.00		
35	WINCHESTER (IM) - IN	T	69.00	34.00	
36	WINCHESTER (IM) - IN	T	69.00	13.00	
37	WOLF LAKE - IN	D	69.00	13.00	
38	WOODS ROAD - IN	D	138.00	12.00	
39	ALMENA - MI	T	69.00	12.00	
40	ALMENA - MI	T	69.00	34.50	

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Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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.
9	1					1
20	1					2
4	1					3
19	2					4
213	2					5
			STATCAP	2	29	6
20	1					7
450	1					8
675	1					9
3	1					10
			STATCAP	1	14	11
500	1					12
2	3					13
2	3					14
20	1					15
42	2					16
56	1					17
20	1					18
54	1					19
20	2					20
7	1					21
7	1					22
22	1					23
20	1					24
22	1					25
22	1					26
5	1					27
8	1					28
9	2					29
42	2					30
84	1					31
20	1					32
			STATCAP	1	5	33
			STATCAP	2	22	34
17	1					35
26	2					36
8	1					37
10	1					38
7	1					39
30	1					40

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	BANGOR - MI	D	69.00	12.00	
2	BARODA - MI	D	138.00	13.09	
3	BENTON HARBOR - MI	T	345.00	137.50	13.80
4	BENTON HARBOR - MI	T	345.00	137.50	13.14
5	BENTON HARBOR WATERWORKS - MI	D	34.50	13.00	
6	BERRIEN SP HYDR STAT - MI	T	34.50	12.00	
7	BERRIEN SP HYDR STAT - MI	T	34.50	13.00	
8	BERRIEN SP HYDR STAT - MI	T	34.50		
9	BRIDGMAN - MI	D	69.00		
10	BRIDGMAN - MI	D	69.00	12.00	
11	BUCHANAN HYDRO STA - MI	T	69.00	12.00	
12	BUCHANAN HYDRO STA - MI	T	69.00	34.00	
13	BUCHANAN SOUTH - MI	D	69.00	12.00	
14	CAMERON - MI	D	69.00	34.00	
15	COLBY - MI	T	138.00	69.00	34.50
16	COLBY - MI	T	69.00	34.50	
17	COLBY - MI	T	138.00	13.09	
18	COLBY - MI	T	34.50		
19	COREY - MI	T	69.00		
20	COREY - MI	T	138.00	69.00	34.50
21	COVERT - MI	D	69.00	13.00	
22	CRYSTAL - MI	D	138.00	13.09	
23	DC COOK 69/12 - MI	T	69.00	13.00	
24	DC COOK 69/12 - MI	T	69.00		
25	DERBY - MI	T	138.00	69.00	34.50
26	EAST WATERVLIET - MI	D	138.00	13.09	
27	EAU CLAIRE - MI	D	34.50	13.00	
28	FLORENCE ROAD - MI	D	69.00	12.00	
29	FLORENCE ROAD - MI	D	69.00		
30	HAGAR - MI	D	69.00	12.00	
31	HARTFORD - MI	T	138.00	69.00	34.00
32	HARTFORD - MI	T	69.00	12.00	
33	HICKORY CREEK - MI	T	138.00	34.50	
34	HICKORY CREEK - MI	T	138.00	69.00	34.50
35	HICKORY CREEK - MI	T	34.50	12.00	
36	INDIAN LAKE - MI	D	34.50	13.00	
37	KENZIE CREEK - MI	T	345.00	137.50	13.80
38	LAKE STREET - MI	T	69.00	34.00	
39	LAKE STREET - MI	T	69.00		
40	LAKESIDE (MBH) - MI	D	69.00	12.00	

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 2018/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.
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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
20	1					2
3600	8					3
224		1				4
1	3					5
5	1					6
5	1					7
			STATCAP	1	10	8
			STATCAP	1	14	9
19	2					10
8	1					11
20	1					12
22	1					13
8	1					14
75	1					15
20	1					16
8	1					17
			STATCAP	1	12	18
			STATCAP	1	14	19
130	1					20
9	1					21
22	1					22
2	1					23
			STATCAP	1		24
75	1					25
20	1					26
4	1					27
20	1					28
			STATCAP	1	10	29
11	1					30
129	1					31
11	1					32
60	2					33
75	1					34
31	2					35
2	1					36
450	1					37
40	1					38
			STATCAP	1	14	39
9	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 2018/Q4

SUBSTATIONS

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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	LAKESIDE (MBH) - MI	D	69.00	13.09	
2	LANGLEY (IM) - MI	D	34.50	13.00	
3	MAIN STREET - MI	T	138.00	34.00	
4	MAIN STREET - MI	T	138.00	13.09	
5	MAIN STREET - MI	T	34.50	4.00	
6	MOORE PARK - MI	T	138.00	13.09	
7	MOORE PARK - MI	T	138.00	69.00	34.50
8	MOORE PARK - MI	T	69.00		
9	MURCH - MI	D	69.00		
10	MURCH - MI	D	69.00	12.00	
11	NEW BUFFALO - MI	D	69.00	12.00	
12	NILES - MI	T	69.00	34.00	
13	NILES - MI	T	69.00	13.09	
14	NILES - MI	T	69.00		
15	PEARL STREET - MI	D	34.50	12.00	
16	PIGEON RIVER - MI	D	69.00	12.00	
17	POKAGON(MBH) - MI	T	69.00	13.00	
18	POKAGON(MBH) - MI	T	138.00	69.00	13.00
19	POKAGON(MBH) - MI	T	69.00		
20	RICKERMAN ROAD - MI	D	138.00	13.09	
21	RIVERSIDE (IM) - MI	T	138.00	69.00	34.00
22	RIVERSIDE (IM) - MI	T	138.00	13.09	
23	RIVERSIDE (IM) - MI	T	138.00		
24	SAUK TRAIL - MI	D	138.00	13.09	
25	SCHOOLCRAFT - MI	D	69.00	13.00	
26	SCOTTDALE - MI	D	34.50	13.09	
27	SISTER LAKES - MI	D	34.50	12.00	
28	SODUS - MI	D	138.00	13.09	
29	STEVENSVILLE - MI	D	69.00	13.00	
30	STEVENSVILLE - MI	D	69.00	13.09	
31	STONE LAKE - MI	D	69.00	12.00	
32	STONE LAKE - MI	D	69.00	13.00	
33	STUBEY ROAD - MI	D	69.00	12.00	
34	STUBEY ROAD - MI	D	69.00		
35	THREE OAKS - MI	D	69.00	12.00	
36	THREE RIVERS (MBH) - MI	D	69.00	12.00	
37	VALLEY - MI	T	138.00	69.00	34.00
38	VICKSBURG - MI	D	69.00	12.00	
39	VICKSBURG - MI	D	69.00	13.09	
40	WEST STREET - MI	D	138.00	13.09	

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 2018/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)	
9	1					1
17	2					2
30	1					3
22	1					4
8	1					5
20	1					6
90	1					7
			STATCAP	1	16	8
			STATCAP	1	13	9
20	1					10
31	2					11
45	1					12
20	1					13
			STATCAP	1	14	14
17	2					15
20	1					16
5	1					17
115	1					18
			STATCAP	1	14	19
8	1					20
134	2					21
20	1					22
			STATCAP	1	53	23
20	1					24
22	1					25
9	1					26
15	2					27
11	1					28
8	1					29
13	1					30
9	1					31
7	1					32
11	1					33
			STATCAP	1	14	34
6	1					35
22	1					36
75	1					37
9	1					38
20	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 2018/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	WHEELER STREET - MI	D	69.00	13.00	
2	WOLVERINE - MI	D	69.00	13.00	2.40
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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 2018/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)	
8	1					1
5	1					2
						3
						4
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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 2018/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	6,689,887
3	AEPSC Support Services	AEPSC	417.1	1,613,607
4	Corporate Communications	AEPSC	920, 923	1,077,255
5	Central Machine Shop	APCO	various	2,380,992
6	Civil & Political Activities and Other Services	AEPSC	426.1,426.3,426.4	988,389
7	Administrative and General Expenses - Maintenance	AEPSC	935	5,037,910
8	Coal Transloading	AEG	151	12,426,936
9	Construction Services	AEPSC	107,108,120	71,618,524
10	Customer Accounts Expense	AEPSC	901-903,905	8,713,852
11	Customer Service & Informational Expense-Operation	AEPSC	907-910	337,636
12	Distribution Expense - Operation	AEPSC	various	3,601,103
13	Distribution Expense - Operation	OPCo	various	269,546
14	Hydraulic Power Generation - Operation	APCo	535, 539	300,832
15	Fuel and Storeroom Services	AEPSC	152,163	6,657,494
16	Hydraulic Power Generation - Maintenance	AEPSC	541-545	515,697
17	Hydraulic Power Generation - Operation	AEPSC	535-539	1,363,142
18	Materials and Supplies	APCo	various	820,387
19	Materials and Supplies	OPCo	various	2,368,012
20	**Non-power Goods or Services Provided for Affiliate**			
21	Assets and Other Debits - Deferred Debits	APCO	184,185,186	330,398
22	Barging	AEG	417	19,928,198
23	Barging	APCO	417	35,066,089
24	Barging	KPCO	417	4,222,046
25	Building and Property Leases	AEPSC	454	1,046,073
26	Fleet and Vehicle Charges	AEPSC	various	456,155
27	Fuel Carbon Activation	AEG	154,502	3,375,422
28	Fuel Consumed - Ammonia	AEG	154,502	292,076
29	Fuel Consumed Handling	AEG	152,501	5,855,221
30	Materials and Supplies	APCO	154	1,099,289
31	Materials and Supplies	OPCo	154	3,988,983
32	Rail Car Lease	SWEPCO	151	1,472,145
33	Services for Rockport	AEG	various	81,729,498
34	Sodium Bicarbonate Activation	AEG	154,502	7,907,218
35	Transmission Expenses - Maintenance	IMTCo	568-571,573	1,425,884
36	Transmission Expenses - Operation	IMTCo	560,562,563,566	2,308,233
37	Use of Jointly Owned Facility	IMTCo	454	2,199,697
38	Revenues from Nonutility Operations	OPCo	417	9,941,045
39	Construction Services	IMTCo	107,108	5,869,019
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Nuclear Power Generation - Operation	AEPSC	517,519,520,524	1,092,908

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 2018/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)
3	Nuclear Power Generation - Maintenance	AEPSC	528,530,531	1,258,489
4	Other Power Supply Expenses	AEPSC	555-557	6,214,530
5	Rail Car Lease	SWEPCO	186	967,300
6	Rail Car Maintenance	AEG	151	1,471,371
7	Rail Car Maintenance	SWEPCO	151	674,429
8	Real Estate & Workplace Services	AEPSC	920, 923	3,118,790
9	Regulatory Services	AEPSC	920, 923	2,419,124
10	Research and Other Services	AEPSC	188	1,536,632
11	Steam Power Generation - Maintenance	AEPSC	510-514	3,071,516
12	Steam Power Generation - Operation	AEPSC	500-502,505-506	8,089,690
13	Strategy & Innovation	AEPSC	920, 923	1,088,402
14	Transmission Expenses - Maintenance	AEPSC	various	782,575
15	Transmission Expenses - Operation	AEPSC	various	6,998,779
16	Treasury & Risk	AEPSC	920,923	1,196,847
17	Utility Operations	AEPSC	920,923	274,808
18	Audit Services	AEPSC	920,923	1,418,394
19	Corporate Accounting	AEPSC	920,923	5,353,094
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Distribution Expenses - Maintenance	OPCo	Various	317,326
3	Corporate Planning & Budgeting	AEPSC	920,923	1,669,771
4	Corporate Safety & Health	AEPSC	920,923	769,356

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 2018/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	508,211
6	Human Resources	AEPSC	920,923	2,945,181
7	Information Technology	AEPSC	920,923	9,469,659
8	Legal GC/Administration	AEPSC	920,923	4,802,481
9	Expenses of nonutility Operations	APCo	417.1	6,190,389
10	Expenses of nonutility Operations	OPCo	417.1	9,941,045
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20	**Non-power Goods or Services Provided for Affiliate**			
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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

107,108,163,500,506,510,511,512,513,524,531,542,543,544

Schedule Page: 429 Line No.: 12 Column: c

580,582,583,584,586,588,589

Schedule Page: 429 Line No.: 13 Column: c

580, 583, 584, 586, 588, 589

Schedule Page: 429 Line No.: 18 Column: c

107,108,154,511,512,513,524,531,543,544,571,592,935

Schedule Page: 429 Line No.: 19 Column: c

107,108,154,570,571,586,588,592,595,935

Schedule Page: 429 Line No.: 26 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.: 33 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.: 14 Column: c

568,569,569.1, 569.2, 569.3,570,571,572,573

Schedule Page: 429.1 Line No.: 15 Column: c

560,561.1,561.2,561.5,561.6,562,563,566,920,923

Schedule Page: 429.2 Line No.: 2 Column: c

592, 593, 594, 595, 596, 597, 598

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/18

RENEWABLE ENERGY RESOURCES

1. Renewable energy means electricity generated using a renewable energy system

2. Report all costs of renewable energy resources under the major classifications provided below and include, as a minimum, the items listed hereunder:
   - A. Biomass
   - B. Solar
   - C. Solar Thermal
   - D. Wind Energy
   - E. Kinetic energy of moving water including:
     - i. Waves, tides or currents
     - ii. Water released through a damn
   - F. Geothermal Energy
   - G. Municipal Solid Waste
   - H. Landfill gas produced by municipal solid waste
   - I. Other

4. In those instances when costs are composites of both actual supportable costs and estimates of costs, specify in column (f) the actual costs that are included in column (e).

5. Report construction work in progress relating to renewable energy resources at line 11.

Line No.	Classification of Cost (a)	Additions (b)	Retirements (c)	Adjustments (d)	Balance at End of Year (e)	Actual Cost (f)
1	Biomass					
2	Solar	7,882	0	0	37,131,156	
3	Solar Thermal					
4	Wind Energy					
5	Kinetic energy of moving water (Hydro)	4,500,394	(344,195)	0	55,663,479	
6	Geothermal Energy					
7	Municipal Solid Waste					
8	Landfill gas produced by municipal solid waste					
9	Other					
10	**TOTAL *(Total of lines 1 thru 9)***	4,508,276	(344,195)	0	92,794,635	
11	Construction work in progress	1,717,847	0	(4,508,276)	6,172,842	