MICHIGAN PUBLIC SERVICE COMMISSION

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

This form is authorized by 1919 PA 419, as amended, authorizes this form being MCL 460.51 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 the Acts.

Report submitted for year ending:

December 31, 2013

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: Brian Frantz **Title:** Manager of Regulated Accounting

Address: 1 Riverside Plaza

City: Columbus **State:** OH **Zip:** 43215

Telephone, Including Area Code: (614) 716-4932

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, 2014

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) 241-0967 or cantinh@michigan.gov OR forward correspondence to:

Michigan Public Service Commission
Financial Analysis & Audit Division (Heather Cantin)
4300 W Saginaw
Lansing, MI 48917

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, 2013
03 Previous Name and Date of Change (if name changed during year)		
04 Address of Principal Business Office at End of Year (Street, City, St., Zip) 1 Riverside Plaza, Columbus, OH 43215-2373		
05 Name of Contact Person Brian Frantz	06 Title of Contact Person Accounting Manager	
07 Address of Contact Person (Street, City, St., Zip) 1 Riverside Plaza, Columbus, OH 43215-2373		
08 Telephone of Contact Person, Including Area Code: (614) 716-4932	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	03 Signature	04 Date Signed (Mo, Da,Yr)
F. Scott Travis		April 25, 2014
02 Title Assistant Controller	F. Scott Travis	

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, 2013

LIST OF SCHEDULES (Electric Utility)

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

2. The "M" prefix below denotes those pages where the information requested by the MPSC differs from that requested by FERC. Each of these pages also contains the "M" designation on the page itself.

Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
GENERAL CORPORATE INFORMATION AND FINANCIAL STATEMENTS		
General Information	101	
Control Over Respondent & Other Associated Companies	M 102	
Corporations Controlled by Respondent	103	FERC Form 1
Officers and Employees	104	
Directors	M 105	
Security Holders and Voting Powers	M 106-107	
Important Changes During the Year	108-109	FERC Form 1
Comparative Balance Sheet	110-113	FERC Form 1
Statement of Income for the Year	114-117	FERC Form 1
Reconciliation of Deferred Income Tax Expense	M 117A-117B	
Statement of Retained Earnings for the Year	M 118-119	FERC Form 1
Statement of Cash Flows	120-121	FERC Form 1
Notes to Financial Statements	122-123	FERC Form 1
Statement of Accumulated Comprehensive Income	122A-122B	FERC Form 1
BALANCE SHEET SUPPORTING SCHEDULES (Assets and Other Debits)		
Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization, and Depletion	200-201	FERC Form 1
Nuclear Fuel Materials	202-203	FERC Form 1
Electric Plant in Service	M 204-211	
Electric Plant Leased to Others	213	NA
Electric Plant Held for Future Use	214	FERC Form 1
Plant Acquisition Adjustments	M 215	
Construction Work in Progress - Electric	M 216	
Construction Overheads	M 217-218	
Accumulated Provision for Depreciation of Electric Utility Plant	M 219	
Nonutility Property	M 221	
Investments	M 222-223	
Investment is Subsidiary Companies	224-225	FERC Form 1
Notes and Accounts Receivable	M 226A/B	
Materials and Supply	227	FERC Form 1
Production Fuel and Oil Stocks	M 227a/b	
Allowances	228 A/B-229 A/B	FERC Form 1
Miscellaneous Current and Accrued Assets	M 230A	
Extraordinary Property Losses	230B	NA
Unrecovered Plant and Regulatory Study Costs	230B	NA
Transmission Service and Generation Interconnection Study	231	FERC Form 1
Other Regulatory Assets	232	FERC Form 1
Miscellaneous Deferred Debits	233	FERC Form 1
Accumulated Deferred Income Taxes (Account 190)	M 234A-B	
Unamortized Loss and Gain on Reacquired Debt	M 237	
BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Credits)		
Capital Stock	250-251	FERC Form 1
Capital Stock Subscribed, Capital Stock Liability for Conversion Premium on Capital Stock, and Installments Received on Capital Stock	252	

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, 2013

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	M	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
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	
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	
Sales of Electricity by Rate Schedules	M	304	
Customer Choice Sales of Electricity by Rate Schedules	M	305	
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	
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 Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2013

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
Generating Plant Statistics - Pumped Storage	416-418	NA
Generating Plant Statistics - Internal Combustion Engine	420-421	NA
Transmission Line Statistics	422-423	FERC Form 1
Transmission Lines Added During Year	424-425	FERC Form 1
Substations	426-427	FERC Form 1
Affiliated Transactions	429	FERC Form 1
Electric Distribution Meters and Line Transformers	429a	
Environmental Protection Facilities	430	NA
Environmental Protection Expenses	431	NA
Footnote Data	450	
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 31,2013

GENERAL INFORMATION

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

F. Scott Travis, Assistant Controller

1 Riverside Plaza

Columbus, OH 43215

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

Indiana - February 21, 1925

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

None

4. State the classes of utility and other services furnished by respondent during the year in each State in which 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) [ ] Yes...Enter date when such independent accountant was initially engaged: _____.

(2) [X] No

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, 2013

CONTROL OVER RESPONDENT & OTHER ASSOCIATED COMPANIES

1. If any corporation, business trust, or similar organization or combination of such organizations jointly held control over the respondent at 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, 2013

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 C&I Company, LLC
- AEP Energy Partners, Inc.
- AEP Generation Resources Inc.

AEP Generating Company
AEP Transmission Holding Company, LLC
AEP Utilities, Inc.
- AEP Texas Central Company
  - AEP Texas Central Transition Funding LLC
  - AEP Texas Central Transition Funding II LLC
  - AEP Texas Central Transition Funding III LLC
- AEP Texas North Company
  - 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 (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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	
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				

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, 2013

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	Base Wages	Other Compensation	Type of Other Compensation	Total Compensation
	(a)	(b)	(c)	(d)	(e)
1	Nicholas K. Akins	1,204,615	2,430,000	A	10,612,588
	Chairman of the Board and		89,973	B	
	Chief Executive Officer		6,720,167	C	
			167,833	D	
2	Brian X. Tierney	675,086	875,500	A	3,521,319
	Executive Vice President & Chief		66,239	B	
	Financial Officer		1,893,044	C	
			11,450	D	
3	Robert P. Powers	675,086	875,500	A	3,521,814
	Executive Vice President & Chief		66,239	B	
	Operating Officer		1,893,044	C	
			11,945	D	
4	David M. Feinberg	552,115	585,000	A	2,278,783
	Executive Vice President & General Counsel		44,896	B	
			1,050,302	C	
			46,470	D	
5	Lana L. Hillebrand	471,808	480,000	A	2,170,638
	Senior Vice President and		16,161	B	
	Chief Administrative Officer		1,146,251	C	
			56,418	D	

Compensation Type Codes:

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

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 31,2013

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
Carla E. Simpson	Fort Wayne, Indiana	N/A	0
Marc E. Lewis - Vice President External 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
J. Edward Ehler - Vice President Distribution Region Operations	Fort Wayne, Indiana	N/A	0
Lisa M. Barton - Vice President ***	Columbus, Ohio	N/A	0
Scott M. Krawec	Fort Wayne, Indiana	N/A	0
Sarah L. Bodner	Fort Wayne, Indiana	N/A	0
Paul Chodak, III - President & COO	Fort Wayne, Indiana	N/A	0
Thomas A. Kratt - Vice President Distribution Operations	Fort Wayne, Indiana	N/A	0
Daniel V. Lee - VP - Generation Assets	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)	December 31, 2013

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 in 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 votes cast by proxy:

Total: 1,400,000

By Proxy: 1,400,000

3. Give the date and place of such meeting:

April 23, 2013 in Columbus, Ohio

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, 2013

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				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					

RESPONSE/NOTES TO INSTRUCTION

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

1. None

2. None

3. None

4. None

5. None

6. Letter of Credit ($150,000) issued by American Electric Power Company, Inc. on behalf of Indiana Michigan Power Company to benefit Travelers Insurance/DC Cook Workers Compensation (FERC Authority Docket No. ES13-37-000)

   Indiana Utility Regulatory Commission Authority (Cause No. 44116)
   Ten Year $250M Senior Unsecured Note at 3.20%, due March 15, 2023

   $101,353,500 nuclear fuel capital lease (Indiana Commission Authority, Cause No. 44116)

   $110,200,000 nuclear fuel capital lease (Indiana Commission Authority, Cause No. 44116)

7. None

8. Tanners Creek employees represented by UWUA Local #418 were provided with a 2.5% general wage increase effective February 16, 2013

   CNP employees represented by IBEW Local #1392 were provided with a 2.5% general wage increase effective April 1, 2013

   River Transportation employees represented by USW Local #14811 were provided with a 2.5% general wage increase extended through March 31, 2015

   Employees represented by USW Local #13729 were provided with a 2.5% general wage increase through November 30, 2014

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

10. None

11. (Reserved)

12. Not Used

13. Lana L. Hillebrand appointed as Vice President effective January 1, 2013
    Shane Q. Lies appointed as Vice President – Site Support Services, Donald C. Cook Plant

effective January 1, 2013
Julia A. Sloat appointed as Treasurer effective January 1, 2013
Marc E. Lewis resigned as Vice President – External Affairs effective January 23, 2013
Marc E. Lewis appointed as Vice President – External & Regulatory Affairs effective January 23, 2013
Carla E. Simpson appointed as Director effective January 23, 2013
Daniel V. Lee resigned as Director and Vice President – Generation Assets effective January 23, 2013
J. Edward Ehler resigned as Director and VP – Distribution Region Operations effective April 24, 2013
Michael Heyeck resigned as Vice President effective April 24, 2013
Thomas A. Kratt appointed as Vice President – Distribution Operations effective July 25, 2013
Thomas A. Kratt appointed as Director effective August 28, 2013

14. Proprietary capital ratio exceeds 30%

This Page Intentionally Left Blank

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 2013/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	7,459,146,326	7,146,373,703
3	Construction Work in Progress (107)	200-201	427,164,224	341,062,641
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		7,886,310,550	7,487,436,344
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	3,567,283,475	3,494,503,152
6	Net Utility Plant (Enter Total of line 4 less 5)		4,319,027,075	3,992,933,192
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	43,302,380	131,795,466
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		2,823,067	119,118,515
10	Spent Nuclear Fuel (120.4)		525,412,331	224,950,629
11	Nuclear Fuel Under Capital Leases (120.6)		261,852,779	176,065,156
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	526,737,873	338,796,232
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		306,652,684	313,133,534
14	Net Utility Plant (Enter Total of lines 6 and 13)		4,625,679,759	4,306,066,726
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		33,575,275	31,134,649
19	(Less) Accum. Prov. for Depr. and Amort. (122)		17,721,722	16,051,403
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	26,504,378	23,725,077
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	-1,057,285	5,066,281
24	Other Investments (124)		15,479,561	16,146,290
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		1,931,609,970	1,705,772,402
29	Special Funds (Non Major Only) (129)		37,278,411	0
30	Long-Term Portion of Derivative Assets (175)		11,494,851	23,428,713
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	140,058
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		2,037,163,439	1,789,362,067
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		1,310,340	1,555,377
36	Special Deposits (132-134)		4,934,604	6,607,488
37	Working Fund (135)		6,200	6,200
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		63,014,473	61,689,515
41	Other Accounts Receivable (143)		5,068,330	15,981,870
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		265,677	229,449
43	Notes Receivable from Associated Companies (145)		42,402,908	103,619,364
44	Accounts Receivable from Assoc. Companies (146)		75,109,148	77,420,899
45	Fuel Stock (151)	227	50,229,820	50,571,903
46	Fuel Stock Expenses Undistributed (152)	227	3,576,877	2,834,549
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	155,833,245	152,386,081
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	3,200,704	3,162,314
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	49,626,805	44,664,483

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 2013/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		-1,057,285	5,066,281
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)		7,334,645	10,850,236
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		78,571	87,204
61	Accrued Utility Revenues (173)		17,292,917	11,217,651
62	Miscellaneous Current and Accrued Assets (174)		28,278,019	125,172,733
63	Derivative Instrument Assets (175)		26,666,341	50,342,631
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		11,494,851	23,428,713
65	Derivative Instrument Assets - Hedges (176)		216,015	199,814
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	140,058
67	Total Current and Accrued Assets (Lines 34 through 66)		523,476,719	689,505,811
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		8,693,163	8,882,013
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	535,130,968	561,922,918
73	Prelim. Survey and Investigation Charges (Electric) (183)		46,324,273	38,133,774
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)		38	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	42,374,616	40,447,626
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)		19,645,219	13,801,938
82	Accumulated Deferred Income Taxes (190)	234	845,488,707	832,086,463
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,497,656,984	1,495,274,732
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		8,683,976,901	8,280,209,336

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 2013/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	900,278,392	795,283,533
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-96,036	-104,879
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)	-15,508,739	-28,884,204
16	Total Proprietary Capital (lines 2 through 15)		1,922,153,922	1,803,774,755
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
19	(Less) Reaquired Bonds (222)	256-257	40,000,000	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	1,905,671,693	1,837,678,888
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		4,195,665	4,388,646
24	Total Long-Term Debt (lines 18 through 23)		1,861,476,028	1,833,290,242
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		147,450,241	115,314,860
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		72,201	111,227
29	Accumulated Provision for Pensions and Benefits (228.3)		26,407,715	98,469,485
30	Accumulated Miscellaneous Operating Provisions (228.4)		2,820,148	967,231
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		6,945,819	13,614,204
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	283,716
34	Asset Retirement Obligations (230)		1,255,184,098	1,192,313,286
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,438,880,222	1,421,074,009
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		142,218,771	208,701,248
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		93,383,898	104,673,457
41	Customer Deposits (235)		31,103,439	31,142,043
42	Taxes Accrued (236)	262-263	26,155,820	40,058,941
43	Interest Accrued (237)		29,475,469	28,921,543
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		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 2013/Q4

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)		5,691,619	4,757,129
48	Miscellaneous Current and Accrued Liabilities (242)		126,641,821	150,642,980
49	Obligations Under Capital Leases-Current (243)		142,579,881	89,395,521
50	Derivative Instrument Liabilities (244)		13,780,467	24,960,732
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		6,945,819	13,614,204
52	Derivative Instrument Liabilities - Hedges (245)		194,429	20,454,658
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	283,716
54	Total Current and Accrued Liabilities (lines 37 through 53)		604,279,795	689,810,332
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	43,199,590	48,130,448
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	57,706,722	65,663,247
60	Other Regulatory Liabilities (254)	278	709,592,999	550,048,798
61	Unamortized Gain on Reaquired Debt (257)		16,691	18,403
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	215,395	246,285
63	Accum. Deferred Income Taxes-Other Property (282)		1,085,021,769	995,757,206
64	Accum. Deferred Income Taxes-Other (283)		961,433,768	872,395,611
65	Total Deferred Credits (lines 56 through 64)		2,857,186,934	2,532,259,998
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		8,683,976,901	8,280,209,336

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 2013/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	2,275,690,830	2,102,317,790		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,500,894,432	1,448,839,540		
5	Maintenance Expenses (402)	320-323	195,891,545	172,562,427		
6	Depreciation Expense (403)	336-337	145,474,651	119,436,675		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	9,600,523	4,030,977		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	20,776,821	20,206,204		
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)		1,875,374	2,945,611		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	82,139,171	73,264,445		
15	Income Taxes - Federal (409.1)	262-263	-55,069,915	-2,962,664		
16	- Other (409.1)	262-263	2,233,755	-2,137,209		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	507,214,371	434,390,785		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	378,405,275	382,595,295		
19	Investment Tax Credit Adj. - Net (411.4)	266	-4,930,858	-4,502,458		
20	(Less) Gains from Disp. of Utility Plant (411.6)		1,866,958	2,395,353		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		381	938		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		2,814,973	11,711,667		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,028,642,229	1,892,794,414		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		247,048,601	209,523,376		

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 2013/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		Line No.
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)	
						1
2,275,690,830	2,102,317,790					2
						3
1,500,894,432	1,448,839,540					4
195,891,545	172,562,427					5
145,474,651	119,436,675					6
9,600,523	4,030,977					7
20,776,821	20,206,204					8
						9
						10
						11
1,875,374	2,945,611					12
						13
82,139,171	73,264,445					14
-55,069,915	-2,962,664					15
2,233,755	-2,137,209					16
507,214,371	434,390,785					17
378,405,275	382,595,295					18
-4,930,858	-4,502,458					19
1,866,958	2,395,353					20
						21
381	938					22
						23
2,814,973	11,711,667					24
2,028,642,229	1,892,794,414					25
247,048,601	209,523,376					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 2013/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)		247,048,601	209,523,376		
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)		122,287,805	118,819,972		
34	(Less) Expenses of Nonutility Operations (417.1)		111,667,724	108,114,338		
35	Nonoperating Rental Income (418)		318,464	446,308		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	8,843	125,886		
37	Interest and Dividend Income (419)		3,318,472	1,602,355		
38	Allowance for Other Funds Used During Construction (419.1)		19,943,467	9,723,922		
39	Miscellaneous Nonoperating Income (421)		5,451,385	2,832,635		
40	Gain on Disposition of Property (421.1)		4,048,738	492,154		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		43,709,450	25,928,894		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		1,764,767	1,655,376		
46	Life Insurance (426.2)					
47	Penalties (426.3)		-26,527	298,557		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		983,903	1,090,205		
49	Other Deductions (426.5)		6,811,173	13,318,100		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		9,533,316	16,362,238		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	6,507,968	7,393,303		
53	Income Taxes-Federal (409.2)	262-263	3,074,320	-3,721,179		
54	Income Taxes-Other (409.2)	262-263	694,041	-435,740		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	14,787,770	6,447,609		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	14,492,933	5,107,546		
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)		10,571,166	4,576,447		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		23,604,968	4,990,209		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		92,594,357	90,701,590		
63	Amort. of Debt Disc. and Expense (428)		2,814,644	2,372,191		
64	Amortization of Loss on Reaquired Debt (428.1)		1,941,251	1,483,709		
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)		70,160			
68	Other Interest Expense (431)		5,483,460	6,217,699		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		9,752,293	4,717,308		
70	Net Interest Charges (Total of lines 62 thru 69)		93,149,867	96,056,169		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		177,503,702	118,457,416		
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)		177,503,702	118,457,416		

This Page Intentionally
Left Blank

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, 2013

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	158,811,498	
3	Account 281		
4	Account 282	122,025,081	
5	Account 283	226,377,792	
6	Account 284		
7	Reconciling Adjustments		
8	TOTAL Account 410.1 (on pages 114-115 line 17)	**507,214,371**	**0**
9	TOTAL Account 410.2 (on page 117 line 55)		
10	Credits to Account 411 from:		
11	Account 190	160,036,162	
12	Account 281	30,890	
13	Account 282	42,123,435	
14	Account 283	176,214,788	
15	Account 284		
16	Reconciling Adjustments		
17	TOTAL Account 411.1 (on page 114-115 line 18)	**378,405,275**	**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	(4,930,858)	
22	ITC Adjustments:		
23	Adjust last year's estimate to actual per filed return		
24	Other (specify)		
25	Net Reconciling Adjustments Account 411.4*	**(4,930,858)**	**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	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, 2013

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
	158,811,498	5,632,923	164,444,421	2
	0		0	3
	122,025,081		122,025,081	4
	226,377,792	9,154,847	235,532,639	5
				6
				7
0	**507,214,371**			8
		14,787,770		9
				10
	160,036,162	7,505,993	167,542,155	11
	30,890		30,890	12
	42,123,435	939	42,124,374	13
	176,214,788	6,986,001	183,200,789	14
				15
				16
0	**378,405,275**			17
		14,492,933		18
				19
				20
	(4,930,858)		(4,930,858)	21
				22
				23
				24
0	**(4,930,858)**	**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 2013/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		792,296,835	749,280,784
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		177,494,859	118,331,530
17	Appropriations of Retained Earnings (Acct. 436)			
18	Reclassification of Appropriated Retained Earnings-Amort Reserve Federal		-260,829	(315,479)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-260,829	(315,479)
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	Dividends Declared - Common Stock		-72,500,000	(75,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-72,500,000	(75,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		897,030,865	792,296,835
	APPROPRIATED RETAINED EARNINGS (Account 215)			

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 2013/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)
39				
40				
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)		3,247,527	2,986,698
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		3,247,527	2,986,698
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		900,278,392	795,283,533
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-104,879	(230,765)
50	Equity in Earnings for Year (Credit) (Account 418.1)		8,843	125,886
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		-96,036	(104,879)

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 2013/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)	177,503,702	118,457,416
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	175,851,995	143,673,856
5	Amortization of Regulatory Debits and Credits	1,875,374	2,945,611
6	Amortization of Nuclear Fuel	135,188,832	142,586,921
7	Accretion of Asset Retirement Obligations	2,814,973	11,711,667
8	Deferred Income Taxes (Net)	129,103,933	53,135,553
9	Investment Tax Credit Adjustment (Net)	-4,930,858	-4,502,458
10	Net (Increase) Decrease in Receivables	11,684,206	30,125,870
11	Net (Increase) Decrease in Inventory	-3,885,799	-9,397,181
12	Net (Increase) Decrease in Allowances Inventory	-4,962,322	-10,188,223
13	Net Increase (Decrease) in Payables and Accrued Expenses	-35,126,644	27,372,601
14	Net (Increase) Decrease in Other Regulatory Assets	-52,631,439	23,194,089
15	Net Increase (Decrease) in Other Regulatory Liabilities	-10,929,188	2,754,027
16	(Less) Allowance for Other Funds Used During Construction	19,943,467	9,723,922
17	(Less) Undistributed Earnings from Subsidiary Companies	8,843	125,886
18	Other (provide details in footnote):	-139,349,101	-79,852,099
19	Mark-to-Market of Risk Management Contracts	12,496,024	12,164,133
20	Pension Contributions to Qualified Plant Trust		-22,285,000
21	Deferred Cook Fire Costs, net of Insurance Proceeds	8,000,000	-8,465,037
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	382,751,378	423,581,938
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-522,255,509	-322,533,951
27	Gross Additions to Nuclear Fuel	-159,328,104	-109,403,450
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-946,995	-1,784,562
30	(Less) Allowance for Other Funds Used During Construction	-19,943,467	-9,723,922
31	Other (provide details in footnote):		
32			
33	Acquired Assets	-644,745	-895,977
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-663,231,886	-424,894,018
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	11,389,575	7,664,444
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)	-909,997,732	-1,045,422,064
45	Proceeds from Sales of Investment Securities (a)	858,405,877	987,549,727

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 2013/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		10
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):	95,506,218	22,555,870
54	(Increase)/Decrease in Other Special Deposits	-1,615,692	77
55	Notes Receivable from Associated Companies	61,216,456	-13,177,043
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-548,327,184	-465,722,997
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	250,000,000	110,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Long Term Issuance Costs	-2,479,868	-1,599,702
66	Net Increase in Short-Term Debt (c)		
67	Proceeds on Nuclear Fuel Sale/Leaseback	211,553,500	109,500,000
68	Proceeds on Capital Leaseback	905,603	280,562
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	459,979,235	218,180,860
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-222,148,466	-100,497,896
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-72,500,000	-75,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	165,330,769	42,682,964
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-245,037	541,905
87			
88	Cash and Cash Equivalents at Beginning of Period	1,561,577	1,019,672
89			
90	Cash and Cash Equivalents at End of period	1,316,540	1,561,577

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

	2013 Cash Flow Incr/Decr	2012 Cash Flow Incr/Decr
Utility Plant, Net	(158,839,569)	(148,402,408)
Property and Investments, Net	(473,943)	6,737,522
Margin Deposits	3,288,576	3,710,796
Prepayments	17,282,070	10,206,105
Accrued Utility Revenues, Net	(6,075,266)	3,561,929
Misc Current and Accrued Assets	5,800,966	(6,443,480)
Unamortized Debt Expense	2,216,600	2,514,710
Other Deferred Debits, Net	(9,098,584)	(1,484,225)
Other Comprehensive Income, Net	(16,113,176)	3,562,374
Unamortized Discount/Premium on LTD	537,089	518,772
Accumulated Provisions - Misc	474,049	(2,955,620)
Current and Accrued Liabilities, Net	(26,157,112)	15,954,098
Other Deferred Credits, Net	47,809,199	32,667,328
Total	(139,349,101)	(79,852,099)

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

	2013	2012
Transformer Sales, Affiliated	503,562	230,671
Meter Sales, Affiliated	1,448,316	974,331
Rotor Sales, Affiliated	349,203	1,810,337
Transco Transfer of Assets	2,729,974	280,358
Sale of Former Breed Plant Land, Non Affiliated	5,542,305	4,368,747
Sale of Land in Clark City, IL, Non Affiliated	816,215	0
Total	11,389,575	7,664,444

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

	2013	2012
NEIL Insurance Settlement	72,000,000	0
Department of Energy Reimbursement	23,506,218	17,712,295
Energy Insurance Services Reimbursement	0	4,843,575
Total	95,506,218	22,555,870

This Page Intentionally
Left Blank

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 2013/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				(12,935,653)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				700,421
3	Preceding Quarter/Year to Date Changes in Fair Value				3,446,092
4	Total (lines 2 and 3)				4,146,513
5	Balance of Account 219 at End of Preceding Quarter/Year				(8,789,140)
6	Balance of Account 219 at Beginning of Current Year				(8,789,140)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				526,247
8	Current Quarter/Year to Date Changes in Fair Value				8,685,964
9	Total (lines 7 and 8)				9,212,211
10	Balance of Account 219 at End of Current Quarter/Year				423,071

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 2013/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	(14,465,399)	(820,358)	(28,221,410)		
2	595,406	1,359,557	2,655,384		
3	(5,776,935)	(987,335)	(3,318,178)		
4	(5,181,529)	372,222	(662,794)	118,457,416	117,794,622
5	(19,646,928)	(448,136)	(28,884,204)		
6	(19,646,928)	(448,136)	(28,884,204)		
7	1,422,079	15,009	1,963,335		
8	2,248,619	477,547	11,412,130		
9	3,670,698	492,556	13,375,465	177,503,702	190,879,167
10	(15,976,230)	44,420	(15,508,739)		

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commmission 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.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

INDEX OF NOTES TO FINANCIAL STATEMENTS

Glossary of Terms for Notes

1. Organization and Summary of Significant Accounting Policies
2. Comprehensive Income
3. Rate Matters
4. Effects of Regulation
5. Commitments, Guarantees and Contingencies
6. Benefit Plans
7. Business Segments
8. Derivatives and Hedging
9. Fair Value Measurements
10. Income Taxes
11. Leases
12. Financing Activities
13. Related Party Transactions
14. Property, Plant and Equipment
15. Sustainable Cost Reductions
16. FERC Order No. 784-A

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 or Parent	American Electric Power Company, Inc., an electric utility holding company.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West Companies	PSO, SWEPCo, TCC and TNC.
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 nonregulated AEP subsidiary that acquired the generation assets and liabilities of OPCo.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CAA	Clean Air Act.
CO_2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, DCC Fuel IV LLC, DCC Fuel V LLC and DCC Fuel VI LLC, formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
FAC	Fuel Adjustment Clause.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
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.
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.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KWh	Kilowatthour.
MISO	Midwest Independent Transmission System Operator.

GLOSSARY OF TERMS FOR NOTES (Continued)

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

Term	Meaning
MLR	Member load ratio, the method used to allocate transactions among members of the Interconnection Agreement.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NO_x	Nitrogen oxide.
NSR	New Source Review.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PCA	Power Coordination Agreement among APCo, I&M and KPCo.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SIA	System Integration Agreement, effective June 15, 2000, 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.
SPP	Southwest Power Pool regional transmission organization.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
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 587,000 retail customers in its service territory in northern and eastern Indiana and a portion of 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.

In accordance with management's December 2010 announcement and an October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated.

Effective January 1, 2014, the FERC approved a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Under the PCA, APCo, I&M and KPCo will be individually responsible for planning their respective capacity obligations and there will be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo, I&M and KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies will fulfill their existing obligations under the PJM Reliability Assurance Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR is committed to make generation available to meet capacity obligations of member companies.

Effective January 1, 2014, AEPSC conducts power, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M and KPCo. Power and natural gas risk management activities are allocated based on the three member companies' respective equity positions and the SIA. I&M shared in coal risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and, to a lesser extent, the purchase and sale of natural gas and coal. The power, natural gas and coal contracts include physical transactions, OTC options and financially-settled swaps and exchange-traded futures and options. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts. For contracts entered and settled prior to January 1, 2014, power and natural gas risk management activities were allocated based on the Interconnection Agreement and the SIA. For contracts entered prior to January 1, 2014 and settled after January 1, 2014, power and natural gas risk management activities are allocated based on frozen MLR ratios as of December 31, 2013. I&M shared in the revenues and expenses associated with these risk management activities with the other AEP East Companies, PSO and SWEPCo.

Under a unit power agreement, I&M purchases AEGCo's 50% share of the 2,620 MW Rockport Plant capacity unless it is sold to other utilities. Another unit power agreement between AEGCo and KPCo provides for the sale of 390 MW of AEGCo's Rockport Plant capacity to KPCo through 2022. Under these agreements, I&M purchases 910 MW of AEGCo's 50% share of Rockport Plant capacity.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East Companies and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East Companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months.

Prior to January 1, 2014, the Interconnection Agreement permitted the AEP East Companies to pool their generation assets on a cost basis. It established an allocation method for generating capacity among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. Members of the Interconnection Agreement were compensated for their costs of energy delivered and charged for energy received. The capacity reserve relationship of the Interconnection Agreement members changed as generating assets were added, retired or sold and relative peak demand changed. The Interconnection Agreement calculated each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation was the MLR, which determined each member's percentage share of revenues and costs.

To minimize the credit requirements and operating constraints when operating within PJM, participating AEP companies, including I&M, agreed to a netting of all payment obligations incurred by any of the AEP companies against all balances due to the 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 AEP companies related to power purchase and sale activity pursuant to the SIA.

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 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 I&M negotiates and files a cost-based contract with the FERC or the FERC determines that I&M has "market power" in the region where the transaction occurs. I&M has entered into wholesale power supply contracts with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually.

The IURC and the MPSC regulate all of the retail distribution operations and rates 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. The FERC claims jurisdiction over retail transmission rates when retail rates are unbundled in connection with restructuring. I&M's retail transmission rates in Michigan are unbundled and are based on formula rates included in the PJM OATT that are cost-based. In Indiana, bundled retail transmission rates are regulated, on a cost basis, by the IURC.

In addition, the FERC regulates the SIA, the Operating Agreement, the System Transmission Integration Agreement, the Transmission Agreement and the Transmission Coordination Agreement, all of which are still active and allocate shared system costs and revenues to AEP East Companies, PSO and SWEPCo that are parties to each agreement.

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 accounting principles generally accepted in the United States of America (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 Accrued 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 change in emission allowances held for speculation as investing activities instead of operating 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 noncurrent tax liabilities related to the accounting guidance for "Uncertainty in Income Taxes" as a current liability rather than a noncurrent liability.
- The classification of regulatory assets and liabilities related to the accounting guidance for "Accounting for Income Taxes" as separate assets and liabilities rather than as a single amount.

- The presentation of 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 of operating expense.
- The classification of certain nonoperating revenues as miscellaneous nonoperating income instead of as operating revenue.
- The classification of certain nonoperating expenses as miscellaneous nonoperating expense instead of as operating expense.
- The separate classification of income tax expense for operating and nonoperating activities instead of as a single income tax expense.
- The classification of DCC Fuel as a 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 plant probable of abandonment in Utility Plant and Construction Work in Progress rather than as Other Property, Plant and Equipment.
- 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.

Accounting for the Effects of Cost-Based Regulation

As a rate-regulated electric public utility company, 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," I&M records regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) 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

For the Years Ended December 31,	2013	2012
	(in thousands)	
Cash was Paid (Received) for:		
Interest (Net of Capitalized Amounts)	$ 85,518	$ 91,448
Income Taxes (Net of Refunds)	(31,220)	(15,117)
Noncash Acquisitions Under Capital Leases	45,230	115,743
As of December 31,		
Construction Expenditures Included in Current and Accrued Liabilities	85,423	112,622
Acquisition of Nuclear Fuel Included in Current and Accrued Liabilities	35	35,493
Expected Reimbursement for SNF Dry Cask Storage	4,352	30,332

Special Deposits

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

Inventory

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

Accounts Receivable

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

Revenue is recognized from electric power sales when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, I&M accrues and recognizes, as Accrued Utility Revenues, 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.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense related to receivables purchased from I&M under a sale of receivables agreement. 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 as of December 31, 2013.

I&M monitors credit levels and the financial condition of its customers on a continuing basis to minimize credit risk. The regulatory commissions allow recovery in rates for a reasonable level of bad debt costs. Management believes adequate provisions for credit loss have been made in the 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. Allowances are consumed in the production of energy and are recorded in Operation Expenses at an average cost. The purchases and sales of allowances are reported in the Operating Activities section of the statements of cash flows.

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 salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to accumulated depreciation. The costs of labor, materials and overhead incurred to operate and maintain plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the 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, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense.

The fair value of an asset or investment is the amount at which that asset or investment 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 or investments 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)

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, accounts receivable and accounts payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

Fair Value Measurements of Assets and Liabilities

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. 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 AEP's Board of Directors. The AEP System's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer.

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 significant portion of the Level 3 instruments have been economically hedged which greatly 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 trusts are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs, primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities and cash equivalent funds. Fixed income securities do not trade on an exchange 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. Benefit plan assets included in Level 3 are primarily real estate and private equity investments that are valued using methods requiring judgment including appraisals.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily on the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are generally deferred as regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally deferred as regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, the IURC and the MPSC review and/or audit I&M's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a FAC under-recovery is no longer probable of recovery, I&M adjusts its FAC deferrals and record provisions for estimated refunds to recognize the probable outcome.

Changes in fuel costs, including purchased power, are reflected in rates through FAC phase-in plans. The FAC generally includes some sharing of off-system sales. A portion of profits from off-system sales are given to customers through the FAC and other rate mechanisms in Indiana and Michigan.

Revenue Recognition

Regulatory Accounting

The financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, I&M records them as assets on the balance sheets. I&M tests 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, I&M writes off that regulatory asset as a charge against income.

Electricity Supply and Delivery Activities

I&M recognizes revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. I&M recognizes the revenues on the statements of income upon delivery of the energy to the customer and includes unbilled as well as billed amounts.

Most of the power produced at the generation plants of the AEP East Companies is sold to PJM. The AEP East Companies purchase power from PJM to supply power to their customers. Generally, these power sales and purchases are reported on a net basis as revenues. However, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are recorded gross as Operation Expenses. Other RTOs do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Operation Expenses. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's economic substance. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Operation Expenses. 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. The unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

AEPSC, on behalf of I&M, engages in wholesale power, coal and natural gas marketing and risk management activities focused on wholesale markets where the AEP System owns assets and adjacent markets. These activities include the purchase-and-sale of energy under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. Certain energy marketing and risk management transactions are with RTOs.

I&M recognizes revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. I&M uses MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or a normal purchase or sale. I&M includes realized gains and losses on wholesale marketing and risk management transactions in revenues on a net basis. The unrealized MTM amounts and some realized gains and losses are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Certain qualifying wholesale marketing and risk management derivatives transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). I&M initially records the effective portion of the cash flow hedge's gain or loss as a component of AOCI. When the forecasted transaction is realized and affects net income, I&M subsequently reclassifies the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on its statements of income. I&M defers the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Accounting for Cash Flow Hedging Strategies" section of Note 8.

Levelization of Nuclear Refueling Outage Costs

In accordance with regulatory orders, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over the period beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins. I&M adjusts the amortization amount as necessary to ensure full amortization of all deferred costs by the end of the refueling cycle.

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.

Income Taxes and Investment Tax Credits

I&M uses the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

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

Investment tax credits are accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are amortized over the life of the plant investment.

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

Excise Taxes

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

Debt

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

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

Investments Held in Trust for Future Liabilities

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and spent nuclear fuel disposal. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity 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 investment policy for the pension fund allocates assets based on the funded status of the pension plan. The objective of the asset allocation policy is to reduce the investment volatility of the plan over time. Generally, more of the investment mix will be allocated to fixed income investments as the plan becomes better funded. Assets will be transferred away from equity investments into fixed income investments based on the market value of plan assets compared to the plan's projected benefit obligation. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	30.0 %
Fixed Income	55.0 %
Other Investments	15.0 %

OPEB Plans Assets	Target
Equity	66.0 %
Fixed Income	33.0 %
Cash	1.0 %

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. Each investment manager's portfolio is compared to a diversified benchmark index.

For equity investments, the 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% 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, the concentration limits must not exceed:

- 3% in any single issuer
- 5% for private placements
- 5% for convertible securities
- 60% for bonds rated AA+ or lower
- 50% for bonds rated A+ or lower
- 10% for bonds rated BBB- or lower

For obligations of non-government issuers, the following limitations apply:

- AAA rated debt: a single issuer should account for no more than 5% of the portfolio.
- AA+, AA, AA- rated debt: a single issuer should account for no more than 3% of the portfolio.
- Debt rated A+ or lower: a single issuer should account for no more than 2% of the portfolio.
- No more than 10% of the portfolio may be invested in high yield and emerging market debt combined at any time.

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 development risk classifications and some investments in Real Estate Investment Trusts (REITs), 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. Commingled private equity funds are used to enhance the holdings' diversity.

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 cash collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the cash collateral is invested. The difference between the rebate owed to the borrower and the cash collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is providing modest incremental income with a limited increase in risk.

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

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

Nuclear Trust Funds

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

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

I&M maintains trust funds for each regulatory jurisdiction. The trust assets may not be used for another jurisdiction's liabilities. 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 the balance sheets. I&M records these securities at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments for investments in both debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the debt and equity investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. I&M records unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. See the "Nuclear Contingencies" section of Note 5 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 9 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss)

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

2. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following table provides the components of changes in AOCI for the year ended December 31, 2013. All amounts in the following table are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2013

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate and Foreign Currency	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in thousands)		
Balance in AOCI as of December 31, 2012	$ (446)	$ (19,647)	$ 4,201	$ (12,991)	$ (28,883)
Change in Fair Value Recognized in AOCI	477	2,249	-	8,511	11,237
Amounts Reclassified from AOCI	15	1,422	700	-	2,137
Net Current Period Other Comprehensive Income	492	3,671	700	8,511	13,374
Balance in AOCI as of December 31, 2013	$ 46	$ (15,976)	$ 4,901	$ (4,480)	$ (15,509)

Reclassifications from Accumulated Other Comprehensive Income

The following table provides details of reclassifications from AOCI for the year ended December 31, 2013. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 6 for additional details.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Year Ended December 31, 2013

Gains and Losses on Cash Flow Hedges	Amount of (Gain) Loss Reclassified from AOCI (in thousands)
Commodity:	
Operating Revenues	$ (155)
Operation Expenses	196
Maintenance Expenses	(14)
Utility Plant	(20)
Regulatory Assets/(Liabilities), Net (a)	16
Subtotal - Commodity	23
Interest Rate and Foreign Currency:	
Interest on Long-term Debt	2,188
Subtotal - Interest Rate and Foreign Currency	2,188
Reclassifications from AOCI, before Income Tax (Expense) Credit	2,211
Income Tax (Expense) Credit	774
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1,437
Pension and OPEB	
Amortization of Prior Service Cost (Credit)	(794)
Amortization of Actuarial (Gains)/Losses	1,872
Change in Funded Status	-
Reclassifications from AOCI, before Income Tax (Expense) Credit	1,078
Income Tax (Expense) Credit	378
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	700
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 2,137

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

The following table provides details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income on the balance sheets and the reasons for changes in cash flow hedges for the year ended December 31, 2012. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2012

	Commodity Contracts	Interest Rate and Foreign Currency Contracts	Total Contracts
		(in thousands)	
Balance in AOCI as of December 31, 2011	$ (819)	$ (14,465)	$ (15,284)
Changes in Fair Value Recognized in AOCI	(987)	(5,777)	(6,764)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Operating Revenues	(43)	-	(43)
Operation Expenses	1,137	-	1,137
Maintenance Expenses	(2)	-	(2)
Interest on Long-Term Debt	-	595	595
Utility Plant	(10)	-	(10)
Regulatory Assets (a)	278	-	278
Balance in AOCI as of December 31, 2012	$ (446)	$ (19,647)	$ (20,093)

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

3. 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.

2011 Indiana Base Rate Case

In February 2013, the IURC issued an order that granted an $85 million annual increase in base rates based upon a return on common equity of 10.2%. In a March 2013 order, the IURC approved an adjustment which increased the authorized annual increase in base rates from $85 million to $92 million. In March 2013, the Indiana Office of Utility Consumer Counselor (OUCC) filed a request for reconsideration with the IURC, which was denied. Also in March 2013, the OUCC filed an appeal of the order with the Indiana Court of Appeals. In September 2013, the OUCC filed a brief on appeal that included objections to the inclusion of a prepaid pension asset in rate base, the use of an end-of-test-year amount for materials and supplies instead of a thirteen-month average and the application of an "outdated" capital structure. If any part of the IURC order is overturned by the Indiana Court of Appeals, it could reduce future net income and cash flows.

Cook Plant Life Cycle Management Project (LCM Project)

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the LCM Project, which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its licensed life (2034 for Unit 1 and 2037 for Unit 2). The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. As of December 31, 2013, I&M has incurred costs of $380 million related to the LCM Project, including AFUDC.

In July 2013, the IURC approved I&M's proposed project with the exception of an estimated $23 million related to certain items that might accommodate a future potential power uprate which the IURC stated I&M could seek recovery of in a subsequent base rate case. I&M will recover approved costs through an LCM rider which will be determined in semi-annual proceedings. The IURC authorized deferral accounting for costs incurred related to certain projects effective January 2012 to the extent such costs are not reflected in rates. In October 2013, I&M filed an application with the IURC for LCM rider rates effective January 2014. In November 2013, the OUCC filed testimony identifying concerns related to the LCM rider that included the use of forecasted capital expenditures and the method used to calculate carrying charges. In December 2013, the IURC issued an interim order authorizing the implementation of LCM rider rates effective January 2014, subject to reconciliation upon the issuance of a final order by the IURC.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project and authorized deferral accounting for costs incurred related to the approved projects effective January 2013 until these costs are included in rates. In February 2013, intervenors filed appeals with the Michigan Court of Appeals objecting to the issuance of the CON as well as the amount of the CON related to the LCM Project.

If I&M is not ultimately permitted to recover its LCM Project costs, it could reduce future net income and cash flows and impact financial condition.

Rockport Plant Clean Coal Technology Project (CCT Project)

In April 2013, I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit both units of the Rockport Plant with a dry sorbent injection system. The estimated cost of the CCT Project was $285 million, excluding AFUDC, to be shared equally between I&M and AEGCo. The application requested deferral treatment of any unrecovered carrying costs incurred during construction and incremental post in-service depreciation expense and operation and maintenance expenses until such costs are recognized and recovered in a rider. I&M also requested cost recovery associated with the retrofit using the Clean Coal Technology Rider recovery mechanism.

In November 2013, the IURC approved a settlement agreement that included the approval of the CPCN with an updated estimated CCT Project cost of $258 million, excluding AFUDC, and the recovery of the Indiana jurisdictional share of I&M's ownership share of $129 million. The settlement agreement specifies that 80% of the recoverable I&M direct ownership share of CCT Project costs will be recovered through a Federal Mandate Rider with the remaining 20% deferred until rates are established in a subsequent rate case. I&M's Indiana allocated share of the CCT Project costs received in the form of purchased power from AEGCo will be recovered in subsequent I&M rate cases. As of December 31, 2013, I&M has incurred costs of $56 million related to the CCT Project, including AFUDC.

Tanners Creek Plant, Units 1 - 4

In 2011, I&M announced that it would retire Tanners Creek Plant, Units 1-3 by June 2015 to comply with proposed environmental regulations. In September 2013, I&M announced that Tanners Creek Plant, Unit 4 would also be retired in mid-2015 rather than being converted from coal to natural gas. I&M is currently recovering depreciation and a return on the net book value of the Tanners Creek Plant in base rates and plans to seek recovery of all of the plant's retirement related costs in its next Indiana and Michigan base rate cases.

In December 2013, I&M filed an application with the MPSC seeking approval of revised depreciation rates for Rockport Plant, Unit 1 and Tanners Creek Plant due to the retirement of the Tanners Creek Plant in 2015. Upon the retirement of the Tanners Creek Plant, I&M proposes that the net book value of the Tanners Creek Plant will be recovered over the remaining life of the Rockport Plant. I&M requested to have the impact of these new depreciation rates incorporated into the rates set in its next rate case. The new depreciation rates result in a decrease in I&M's Michigan jurisdictional electric depreciation expense which I&M proposes to implement in the month following a MPSC order in the revised depreciation case.

As of December 31, 2013, the net book value of the Tanners Creek Plant was $341 million, before cost of removal, including materials and supplies inventory and CWIP. If I&M is ultimately not permitted to fully recover its net book value of the Tanners Creek Plant and its retirement-related costs, it could reduce future net income and cash flows and impact financial condition.

Termination of Interconnection Agreement

In accordance with management's December 2010 announcement and October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated.

In December 2013, the FERC issued orders approving the creation of a PCA, effective January 1, 2014, conditioned upon certain compliance filings which were filed with the FERC in January 2014. The PCA was established among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Under the PCA, APCo and I&M would be individually responsible for planning their respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo and I&M to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies will fulfill their existing obligations under the PJM Reliability Assurance Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR is committed to meet capacity obligations of member companies through May 31, 2015.

If I&M experiences a decrease in revenues or an increase in expenses as a result of changes to its relationship with affiliates and is unable to recover the change in revenues and costs through rates, prices or additional sales, it could reduce future net income and cash flows.

4. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	December 31, 2013	December 31, 2012	Remaining Recovery Period
	(in thousands)		
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:			
Regulatory Assets Currently Not Earning a Return			
Indiana Under-recovered Capacity Costs	$ 21,945	$ -	
Indiana Deferred Cook Plant Life Cycle Management Project Costs	4,093	-	
Stranded Costs on Abandoned Plants	3,896	-	
Storm Related Costs	1,836	-	
Mountaineer Carbon Capture and Storage Commercial Scale Facility	-	1,380	
Litigation Settlement	-	11,098	
Other Regulatory Assets Not Yet Being Recovered	3,616	786	
Total Regulatory Assets Not Yet Being Recovered	35,386	13,264	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Unamortized Loss on Reacquired Debt	1,863	2,070	19 years
RTO Formation/Integration Costs	2,544	3,229	6 years
Cook Plant, Unit 2 Baffle Bolts	7,248	-	25 years
Under-recovered Fuel Costs	-	3,037	
Customer Choice Implementation Costs	-	1,493	
Other Regulatory Assets Being Recovered	522	-	various
Regulatory Assets Currently Not Earning a Return			
Income Tax Assets	277,743	253,148	30 years
Pension and OPEB Funded Status	100,132	220,797	11 years
Medicare Subsidy	11,221	-	11 years
Litigation Settlement	10,382	-	12 years
Postemployment Benefits	9,096	8,897	5 years
Deferred Restructuring Costs	2,423	3,688	2 years
Asset Retirement Obligation	696	808	7 years
Cook Nuclear Plant Refueling Outage Levelization	57,979	26,652	3 years
Under-recovered Fuel Costs	3,397	1,772	1 year
Off-system Sales Margin Sharing	4,409	-	1 year
Deferred PJM Fees	-	13,998	
River Transportation Division Expenses	4,090	4,576	1 year
Peak Demand Reduction/Energy Efficiency	4,457	2,608	1 year
Other Regulatory Assets Being Recovered	1,543	1,886	various
Total Regulatory Assets Being Recovered	499,745	548,659	
Total FERC Account 182.3 Regulatory Assets	$ 535,131	$ 561,923	

Regulatory Liabilities:	December 31, 2013	December 31, 2012	Remaining Refund Period
	(in thousands)		
Regulatory liabilities not yet being paid:			
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Not Yet Being Paid	$ 113	$ 124	
Total Regulatory Liabilities Not Yet Being Paid	113	124	
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Not Paying a Return			
Income Tax Liabilities	27,265	30,896	30 years
Unrealized Gain on Forward Commitments	10,810	19,872	4 years
Peak Demand Reduction/Energy Efficiency	15,021	11,080	1 year
Excess Asset Retirement Obligations for Nuclear Decommissioning Liability	597,113	435,717	(a)
Spent Nuclear Fuel Liability	43,416	42,898	(a)
Over-recovery of PJM Expenses	13,924	-	2 year
Over-recovered Fuel Costs	1,924	-	1 year
Off-system Sales Margin Sharing	-	7,611	
Indiana Clean Coal Technology Rider	7	774	1 year
Other Regulatory Liabilities Being Paid	-	1,077	
Total Regulatory Liabilities Being Paid	709,480	549,925	
Total FERC Account 254 Regulatory Liabilities	$ 709,593	$ 550,049	

(a) Relieved when plant is decommissioned.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

I&M is subject to certain claims and legal actions arising in its 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. 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

Construction and Commitments

I&M has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, I&M contractually commits to third-party construction vendors for certain material purchases and other construction services. I&M also purchases fuel, materials, supplies, services and property, plant and equipment under contract as part of its normal course of business. Certain supply contracts contain penalty provisions for early termination.

The following table summarizes the actual contractual commitments as of December 31, 2013:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 456,669	$ 477,289	$ 251,669	$ 427,000	$ 1,612,627
Energy and Capacity Purchase Contracts	107,567	216,716	219,249	819,754	1,363,286
Construction Contracts for Capital Assets (b)	7,544	-	-	-	7,544
Total	$ 571,780	$ 694,005	$ 470,918	$ 1,246,754	$ 2,983,457

(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.

(b) Represents only capital assets for which there are signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

GUARANTEES

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

Letters of Credit

I&M enters into standby letters of credit with third parties. These letters of credit are issued in the ordinary course of business and cover items such as insurance programs, security deposits and debt service reserves.

AEP has two revolving credit facilities totaling $3.5 billion, under which up to $1.2 billion may be issued as letters of credit. As of December 31, 2013, I&M's maximum future payments for letters of credit issued under the revolving credit facilities were $150 thousand with a maturity of March 2014.

I&M has $77 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $77.9 million with a maturity of March 2015.

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, 2013, there were no material liabilities recorded for any indemnifications.

I&M is jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East Companies related to power purchase and sale activity pursuant to the SIA.

Lease Obligations

I&M leases certain equipment under master lease agreements. See "Master Lease Agreements" and "Railcar Lease" sections of Note 11 for disclosure of lease residual value guarantees.

ENVIRONMENTAL CONTINGENCIES

Carbon Dioxide Public Nuisance Claims

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011. Plaintiffs refiled their complaint in federal district court. The court ordered all defendants to respond to the refiled complaints in October 2011. In March 2012, the court granted the defendants' motion for dismissal on several grounds, including the doctrine of collateral estoppel and the applicable statute of limitations. In May 2013, the U.S. Court of Appeals for the Fifth Circuit affirmed the district court's dismissal of the complaint. The plaintiffs did not appeal to the U.S. Supreme Court.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. In September 2012, the Ninth Circuit Court of Appeals affirmed the trial court's decision, holding that the CAA displaced Kivalina's claims for damages. Plaintiffs filed seeking further review in the U.S. Supreme Court. In May 2013, the U.S. Supreme Court denied the plaintiffs' request for review.

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

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

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. There is one site for which I&M received an information request which could lead to Potentially Responsible Party (PRP) designation. As of December 31, 2013, I&M has been named potentially liable at two sites under state law including the site discussed in the next paragraph. In those instances where I&M has been named a PRP or defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ. I&M's reserve is approximately $8 million. As the remediation work is completed, I&M's cost may change as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation required by the MDEQ. Management cannot predict the amount of additional cost, if any.

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

NUCLEAR CONTINGENCIES

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission (NRC). I&M has a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generating 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 liability could be substantial.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The most recent decommissioning cost study was performed in 2012. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste ranges from $1.3 billion to $1.7 billion in 2012 nondiscounted dollars. The wide range in estimated costs is caused by variables in assumptions. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were $10 million and $14 million for the years ended December 31, 2013 and 2012, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2013 and 2012, the total decommissioning trust fund balance was $1.6 billion and $1.4 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including interest, unrealized gains and losses and expenses of the trust funds) increase or decrease the recorded liability.

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

SNF Disposal

The Federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWh for fuel consumed after April 6, 1983 at the Cook Plant is being collected from customers and remitted to the U.S. Treasury. As of December 31, 2013 and 2012, fees and related interest of $265 million and $265 million, respectively, for fuel consumed prior to April 7, 1983 have been recorded as Other Long-term Debt and funds collected from customers along with related earnings totaling $309 million and $308 million, respectively, to pay the fee are recorded as part of Other Special Funds. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

In 2011, I&M signed a settlement agreement with the Federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government's delays in accepting SNF for permanent storage. Under the settlement agreement, I&M received $31 million and $20 million in 2013 and 2012, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2016. The proceeds reduced costs for dry cask storage. As of December 31, 2013, I&M has deferred $29 million in Miscellaneous Current and Accrued Assets on the balance sheet of dry cask storage and related operation and maintenance costs for recovery under this agreement.

See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 9 for disclosure of the fair value of assets within the trusts.

Nuclear Incident Liability

I&M carries insurance coverage for a nuclear incident at the Cook Plant for property damage, decommissioning and decontamination in the amount of $2.8 billion. Insurance coverage for a nonnuclear incident at the Cook Plant is $1.7 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. Participation in this mutual insurance requires a contingent financial obligation of up to $39 million for I&M which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public liability arising from a nuclear incident at $13.6 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $375 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 $121 million on each licensed reactor in the U.S. payable in annual installments of $19 million. As a result, I&M could be assessed $242 million per nuclear incident payable in annual installments of $38 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is initially covered for the first $375 million through commercially available insurance. The next level of liability coverage of up to $13.2 billion would be covered by claims made under the Price-Anderson Act. If the liability were in excess of amounts recoverable from insurance and retrospective claim payments made under the Price-Anderson Act, I&M would seek to recover those amounts from customers through rate increases. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and 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. Insurance coverage includes all risks of physical loss or damage to nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of retentions absorbed by I&M. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

See "Nuclear Contingencies" section of this footnote for a discussion of I&M's nuclear exposures and related insurance.

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

Rockport Plant Litigation

In July 2013, the Wilmington Trust Company filed a complaint in U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiff further alleges that the defendants' actions constitute breach of the lease and participation agreement. The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff. The New York court has granted the motion to transfer this case to the U.S. District Court for the Southern District of Ohio. The motion to dismiss, filed in October 2013, is pending. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

6. BENEFIT PLANS

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

I&M participates in an AEP sponsored qualified pension plan and two unfunded nonqualified pension plans. Substantially all employees are covered by the qualified plan or both the qualified and nonqualified pension plans. 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 in its 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 recognizes, 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 as of December 31 of each year used in the measurement of benefit obligations are shown in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	2013	2012	2013	2012
Discount Rate	4.70 %	3.95 %	4.70 %	3.95 %
Rate of Compensation Increase	4.90 % (a)	5.00 % (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

NA Not applicable.

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

For 2013, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 11.5% per year, with an average increase of 4.9%.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1 of each year used in the measurement of benefit costs are shown in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2013**	**2012**	**2013**	**2012**
Discount Rate	3.95 %	4.55 %	3.95 %	4.75 %
Expected Return on Plan Assets	6.50 %	7.25 %	7.00 %	7.25 %
Rate of Compensation Increase	5.00 %	5.00 %	NA	NA

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 and current prospects for economic growth.

The health care trend rate assumptions as of January 1 of each year used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	2013	2012
Initial	6.75 %	7.00 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2020	2020

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

	1% Increase	1% Decrease
	(in thousands)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 579	$ (382)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	6,884	(5,603)

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, 2013, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status as of December 31, 2013 and 2012

The following table provides a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets and funded status as of December 31. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans		Other Postretirement Benefit Plans	
	2013	2012	2013	2012
Change in Benefit Obligation	(in thousands)			
Benefit Obligation as of January 1,	$ 618,974	$ 581,249	$ 213,770	$ 273,011
Service Cost	8,736	9,908	3,219	6,621
Interest Cost	24,100	26,227	8,221	12,590
Actuarial (Gain) Loss	(41,632)	44,922	(48,113)	13,145
Plan Amendment Prior Service Credit	-	-	-	(78,851)
Benefit Payments	(35,479)	(43,332)	(16,503)	(18,132)
Participant Contributions	-	-	4,745	4,226
Medicare Subsidy	-	-	1,158	1,160
Benefit Obligation as of December 31,	$ 574,699	$ 618,974	$ 166,497	$ 213,770
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 551,602	$ 503,471	$ 194,128	$ 181,237
Actual Gain on Plan Assets	43,009	69,167	23,844	14,357
Company Contributions	11	22,296	-	12,440
Participant Contributions	-	-	4,745	4,226
Benefit Payments	(35,479)	(43,332)	(16,503)	(18,132)
Fair Value of Plan Assets as of December 31,	$ 559,143	$ 551,602	$ 206,214	$ 194,128
Funded (Underfunded) Status as of December 31,	$ (15,556)	$ (67,372)	$ 39,717	$ (19,642)

Amounts Recognized on the Balance Sheets as of December 31, 2013 and 2012

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2013	2012	2013	2012
	(in thousands)			
Special Funds - Prepaid Benefit Costs	$ -	$ -	$ 37,278	$ -
Miscellaneous Current and Accrued Liabilities - Short-term Benefit Liability	(43)	(15)	-	-
Accumulated Provision for Pensions and Benefits - Long-term Benefit Liability	(15,513)	(67,357)	2,439	(19,642)
Funded (Underfunded) Status	$ (15,556)	$ (67,372)	$ 39,717	$ (19,642)

Amounts Included in AOCI and Regulatory Assets as of December 31, 2013 and 2012

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2013	2012	2013	2012
Components	(in thousands)			
Net Actuarial Loss	$ 137,975	$ 211,477	$ 57,260	$ 123,560
Prior Service Cost (Credit)	706	901	(94,538)	(103,959)
Recorded as				
Regulatory Assets	$ 134,560	$ 202,821	$ (34,428)	$ 17,976
Deferred Income Taxes	1,442	3,345	(997)	569
Net of Tax AOCI	2,679	6,212	(1,853)	1,056

Components of the change in amounts included in AOCI and regulatory assets during the years ended December 31, 2013 and 2012 are as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2013	2012	2013	2012
Components	(in thousands)			
Actuarial (Gain) Loss During the Year	$ (51,815)	$ 13,289	$ (58,774)	$ 11,254
Prior Service Credit	-	-	-	(78,851)
Amortization of Actuarial Loss	(21,687)	(17,558)	(7,526)	(6,918)
Amortization of Prior Service Credit (Cost)	(195)	(406)	9,421	2,383
Change for the Year	$ (73,697)	$ (4,675)	$ (56,879)	$ (72,132)

Pension and Other Postretirement Plans' Assets

The following table presents the classification of pension plan assets within the fair value hierarchy as of December 31, 2013:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 129,561	$ -	$ -	$ -	$ 129,561	23.2 %
International	61,071	-	-	-	61,071	10.9 %
Real Estate Investment Trusts	6,872	-	-	-	6,872	1.2 %
Common Collective Trust - International	-	1,159	-	-	1,159	0.2 %
Subtotal - Equities	197,504	1,159	-	-	198,663	35.5 %
Fixed Income:						
Common Collective Trust - Debt	-	3,077	-	-	3,077	0.5 %
United States Government and Agency Securities	-	45,904	-	-	45,904	8.2 %
Corporate Debt	-	189,896	-	-	189,896	34.0 %
Foreign Debt	-	40,794	-	-	40,794	7.3 %
State and Local Government	-	3,321	-	-	3,321	0.6 %
Other - Asset Backed	-	3,951	-	-	3,951	0.7 %
Subtotal - Fixed Income	-	286,943	-	-	286,943	51.3 %
Real Estate	-	-	28,275	-	28,275	5.0 %
Alternative Investments	-	-	39,121	-	39,121	7.0 %
Securities Lending	-	4,175	-	-	4,175	0.8 %
Securities Lending Collateral (a)	-	-	-	(5,363)	(5,363)	(0.9)%
Cash and Cash Equivalents	-	5,766	-	-	5,766	1.0 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	1,563	1,563	0.3 %
Total	$ 197,504	$ 298,043	$ 67,396	$ (3,800)	$ 559,143	100.0 %

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

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

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

	Real Estate	Alternative Investments	Total Level 3
		(in thousands)	
Balance as of January 1, 2013	$ 25,791	$ 22,974	$ 48,765
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	3,560	1,728	5,288
Relating to Assets Sold During the Period	-	1,743	1,743
Purchases and Sales	(1,076)	12,676	11,600
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2013	$ 28,275	$ 39,121	$ 67,396

The following table presents the classification of OPEB plan assets within the fair value hierarchy as of December 31, 2013:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 57,460	$ -	$ -	$ -	$ 57,460	27.9 %
International	74,705	-	-	-	74,705	36.2 %
Common Collective Trust - Global	-	1,783	-	-	1,783	0.9 %
Subtotal - Equities	132,165	1,783	-	-	133,948	65.0 %
Fixed Income:						
Common Collective Trust - Debt	-	10,669	-	-	10,669	5.2 %
United States Government and Agency Securities	-	6,860	-	-	6,860	3.3 %
Corporate Debt	-	13,363	-	-	13,363	6.5 %
Foreign Debt	-	2,610	-	-	2,610	1.2 %
State and Local Government	-	562	-	-	562	0.3 %
Other - Asset Backed	-	986	-	-	986	0.5 %
Subtotal - Fixed Income	-	35,050	-	-	35,050	17.0 %
Trust Owned Life Insurance:						
International Equities	-	1,607	-	-	1,607	0.8 %
United States Bonds	-	25,679	-	-	25,679	12.4 %
Cash and Cash Equivalents	8,283	1,064	-	-	9,347	4.5 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	583	583	0.3 %
Total	$ 140,448	$ 65,183	$ -	$ 583	$ 206,214	100.0 %

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

The following table presents the classification of pension plan assets within the fair value hierarchy as of December 31, 2012:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 153,658	$ -	$ -	$ -	$ 153,658	27.9 %
International	58,355	-	-	-	58,355	10.5 %
Real Estate Investment Trusts	10,637	-	-	-	10,637	1.9 %
Common Collective Trust - International	-	510	-	-	510	0.1 %
Subtotal - Equities	222,650	510	-	-	223,160	40.4 %
Fixed Income:						
Common Collective Trust - Debt	-	3,727	-	-	3,727	0.7 %
United States Government and Agency Securities	-	84,024	-	-	84,024	15.2 %
Corporate Debt	-	145,081	-	-	145,081	26.3 %
Foreign Debt	-	23,332	-	-	23,332	4.2 %
State and Local Government	-	5,166	-	-	5,166	0.9 %
Other - Asset Backed	-	4,184	-	-	4,184	0.8 %
Subtotal - Fixed Income	-	265,514	-	-	265,514	48.1 %
Real Estate	-	-	25,791	-	25,791	4.7 %
Alternative Investments	-	-	22,974	-	22,974	4.2 %
Securities Lending	-	9,436	-	-	9,436	1.7 %
Securities Lending Collateral (a)	-	-	-	(10,672)	(10,672)	(1.9)%
Cash and Cash Equivalents	-	14,772	-	-	14,772	2.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	627	627	0.1 %
Total	$ 222,650	$ 290,232	$ 48,765	$ (10,045)	$ 551,602	100.0 %

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

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

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

	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2012	$ 746	$ 19,112	$ 18,762	$ 38,620
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	3,533	1,203	4,736
Relating to Assets Sold During the Period	(263)	-	583	320
Purchases and Sales	(483)	3,146	2,426	5,089
Transfers into Level 3	-	-	-	-
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2012	$ -	$ 25,791	$ 22,974	$ 48,765

The following table presents the classification of OPEB plan assets within the fair value hierarchy as of December 31, 2012:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 52,245	$ -	$ -	$ -	$ 52,245	26.9 %
International	62,466	-	-	-	62,466	32.2 %
Subtotal - Equities	114,711	-	-	-	114,711	59.1 %
Fixed Income:						
Common Collective Trust - Debt	-	8,982	-	-	8,982	4.6 %
United States Government and Agency Securities	-	10,176	-	-	10,176	5.2 %
Corporate Debt	-	19,167	-	-	19,167	9.9 %
Foreign Debt	-	3,240	-	-	3,240	1.7 %
State and Local Government	-	901	-	-	901	0.5 %
Other - Asset Backed	-	1,217	-	-	1,217	0.6 %
Subtotal - Fixed Income	-	43,683	-	-	43,683	22.5 %
Trust Owned Life Insurance:						
International Equities	-	6,380	-	-	6,380	3.3 %
United States Bonds	-	20,128	-	-	20,128	10.3 %
Cash and Cash Equivalents	7,684	1,412	-	-	9,096	4.7 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	130	130	0.1 %
Total	$ 122,395	$ 71,603	$ -	$ 130	$ 194,128	100.0 %

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

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.

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

Accumulated Benefit Obligation	December 31, 2013	2012
	(in thousands)	
Qualified Pension Plan	$ 560,443	$ 603,461
Nonqualified Pension Plans	326	200
Total	$ 560,769	$ 603,661

For the underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets of these plans as of December 31, 2013 and 2012 were as follows:

	December 31, 2013	2012
	(in thousands)	
Projected Benefit Obligation	$ 574,699	$ 618,974
Accumulated Benefit Obligation	$ 560,769	$ 603,661
Fair Value of Plan Assets	559,143	551,602
Underfunded Accumulated Benefit Obligation	$ (1,626)	$ (52,059)

Estimated Future Benefit Payments and Contributions

I&M expects contributions and payments for the pension plans of $7.3 million during 2014. For the pension plans, this amount includes the payment of unfunded nonqualified benefits plus contributions to the qualified trust fund of at least the minimum amount required by the Employee Retirement Income Security Act. For the qualified pension plan, I&M may also make additional discretionary contributions to maintain the funded status of the plan.

The table below reflects the total benefits expected to be paid from the plan or from I&M's assets. The payments include the participants' contributions to the plan for their share of the cost. In November 2012, changes to the retiree medical coverage were announced. Effective for retirements after December 2012, contributions to retiree medical coverage were capped reducing exposure to future medical cost inflation. Effective for employees hired after December 2013, retiree medical coverage will not be provided. The impact of the changes is reflected in the Benefit Plan Obligation table as plan amendments. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for pension benefits and OPEB are as follows:

	Estimated Payments	
	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
2014	$ 37,708	$ 16,665
2015	38,835	17,533
2016	39,293	18,350
2017	40,929	18,794
2018	41,453	19,124
Years 2019 to 2023, in Total	218,392	101,425

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost (credit) for the years ended December 31, 2013 and 2012:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2013	2012	2013	2012
	(in thousands)			
Service Cost	$ 8,736	$ 9,908	$ 3,219	$ 6,621
Interest Cost	24,100	26,227	8,221	12,590
Expected Return on Plan Assets	(32,826)	(37,533)	(13,183)	(12,847)
Amortization of Prior Service Cost (Credit)	195	406	(9,421)	(2,383)
Amortization of Net Actuarial Loss	21,687	17,558	7,526	6,918
Net Periodic Benefit Cost (Credit)	21,892	16,566	(3,638)	10,899
Capitalized Portion	(4,575)	(3,114)	760	(2,049)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 17,317	$ 13,452	$ (2,878)	$ 8,850

Estimated amounts expected to be amortized to net periodic benefit costs (credits) and the impact on the balance sheet during 2014 is shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
Net Actuarial Loss	$ 14,708	$ 2,341
Prior Service Cost (Credit)	195	(9,421)
Total Estimated 2014 Amortization	$ 14,903	$ (7,080)
Expected to be Recorded as		
Regulatory Asset	$ 14,010	$ (6,446)
Deferred Income Taxes	313	(222)
Net of Tax AOCI	580	(412)
Total	$ 14,903	$ (7,080)

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, 2013 and 2012 was $10 million and $9.7 million, respectively.

7. BUSINESS SEGMENTS

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

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

I&M is exposed to certain market risks as a major power producer and marketer of wholesale electricity, natural gas, coal and emission allowances. These risks include commodity price risk, interest rate risk, credit risk and, to a lesser extent, 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. AEPSC, on behalf of I&M, manages these risks using derivative instruments.

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, focusing on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which AEPSC transacts on behalf of I&M. To accomplish these objectives, AEPSC, on behalf of 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.

AEPSC, on behalf of I&M, enters into power, 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. AEPSC, on behalf of I&M, enters into 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. AEPSC, on behalf of I&M, also engages in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. For disclosure purposes, these risks are grouped as "Interest Rate and Foreign Currency." 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 AEP's Board of Directors.

The following table represents the gross notional volume of outstanding derivative contracts as of December 31, 2013 and 2012:

Notional Volume of Derivative Instruments

	Volume		
	December 31,		
Primary Risk Exposure	2013	2012	Unit of Measure
	(in thousands)		
Commodity:			
Power	33.231	64,791	MWhs
Coal	3,389	2,711	Tons
Natural Gas	1,680	6,922	MMBtus
Heating Oil and Gasoline	521	532	Gallons
Interest Rate	$ 8,627	$ 16,584	USD
Interest Rate and Foreign Currency	$ -	$ 200,000	USD

Fair Value Hedging Strategies

AEPSC, on behalf of I&M, enters into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify an exposure to interest rate risk by converting a portion of fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives are designated as fair value hedges.

Cash Flow Hedging Strategies

AEPSC, on behalf of I&M, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of power, coal, natural gas and heating oil and gasoline ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. 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 fuel or energy purchases. I&M does not hedge all commodity price risk.

I&M's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of I&M, enters into financial heating oil and gasoline derivative contracts in order to mitigate price risk of future fuel purchases. For disclosure purposes, these contracts are included with other hedging activities as "Commodity." I&M does not hedge all fuel price risk.

AEPSC, on behalf of I&M, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of floating-rate debt to a fixed rate. AEPSC, on behalf of I&M, also enters into interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. The forecasted fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. 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, AEPSC, on behalf of I&M, may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. I&M does not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheet at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, management also 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. For the December 31, 2013 and 2012 balance sheets, I&M netted cash collateral received from third parties against short-term and long-term risk management assets and cash collateral paid to third parties against short-term and long-term risk management liabilities as follows:

December 31,			
2013		2012	
Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities
(in thousands)			
$ -	$ 2,030	$ 867	$ 7,576

The following tables represent the gross fair value of derivative activity on the balance sheets as of December 31, 2013 and 2012:

Fair Value of Derivative Instruments
December 31, 2013

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (d)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
			(in thousands)			
Derivative Instrument Assets	$ 47,437	$ -	$ -	$ 47,437	$ (20,770)	$ 26,667
Long-Term Portion of Derivative Instrument Assets	14,208	-	-	14,208	(2,713)	11,495
Derivative Instrument Assets – Hedges	-	234	-	234	(18)	216
Derivative Instrument Liabilities	36,581	-	-	36,581	(22,800)	13,781
Long-Term Portion of Derivative Instrument Liabilities	9,802	-	-	9,802	(2,856)	6,946
Derivative Instrument Liabilities – Hedges	-	212	-	212	(18)	194

Fair Value of Derivative Instruments
December 31, 2012

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (d)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
			(in thousands)			
Derivative Instrument Assets	$ 134,821	$ -	$ -	$ 134,821	$ (84,478)	$ 50,343
Long-Term Portion of Derivative Instrument Assets	41,553	-	-	41,553	(18,124)	23,429
Derivative Instrument Assets – Hedges	-	368	-	368	(168)	200
Long-Term Portion of Derivative Instrument Assets – Hedges	-	148	-	148	(8)	140
Derivative Instrument Liabilities	116,147	-	-	116,147	(91,187)	24,960
Long-Term Portion of Derivative Instrument Liabilities	33,714	-	-	33,714	(20,100)	13,614
Derivative Instrument Liabilities – Hedges	-	1,099	19,524	20,623	(168)	20,455
Long-Term Portion of Derivative Instrument Liabilities – Hedges	-	292	-	292	(8)	284

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."

(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The table below presents the activity of derivative risk management contracts for the years ended December 31, 2013 and 2012:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2013	2012
	(in thousands)	
Operating Revenues	$ 10,624	$ 11,437
Regulatory Assets (a)	(26)	(9,204)
Regulatory Liabilities (a)	(9,062)	(889)
Total Gain on Risk Management Contracts	$ 1,536	$ 1,344

(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. However, unrealized and some realized gains and losses in regulated jurisdictions 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 Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk impacts Net Income during the period of change.

I&M records realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest on Long-term Debt on the statements of income. During 2013 and 2012, I&M did not designate any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), I&M initially reports the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income on the balance sheets until the period the hedged item affects Net Income. I&M's hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal and natural gas designated as cash flow hedges are included in Operating Revenues or Operation Expenses on the statements of income or in regulatory assets or regulatory liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During 2013 and 2012, I&M designated power, coal and natural gas derivatives as cash flow hedges.

I&M reclassifies gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income on the balance sheets into Operation Expenses, Maintenance Expenses or Depreciation Expense, as it relates to capital projects, on the statements of income. During 2013 and 2012, I&M designated heating oil and gasoline derivatives as cash flow hedges.

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 2013 and 2012, I&M designated interest rate derivatives as cash flow hedges.

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 2013 and 2012, I&M did not designate any foreign currency derivatives as cash flow hedges.

During 2013 and 2012, hedge ineffectiveness was immaterial or nonexistent for all of the hedge strategies disclosed above.

For details on designated, 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 2.

Cash flow hedges included in Accumulated Other Comprehensive Income on the balance sheets as of December 31, 2013 and 2012 were:

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2013

	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Hedging Assets (a)	$ 216	$ -	$ 216
Hedging Liabilities (a)	194	-	194
AOCI Gain (Loss) Net of Tax	46	(15,976)	(15,930)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	46	(1,568)	(1,522)

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2012

	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Hedging Assets (a)	$ 200	$ -	$ 200
Hedging Liabilities (a)	931	19,524	20,455
AOCI Loss Net of Tax	(446)	(19,647)	(20,093)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(355)	(1,600)	(1,955)

(a) Hedging assets and hedging liabilities are included in Derivative Instrument Assets – Hedges and Derivative Instrument Liabilities – Hedges on the balance sheets.

The actual amounts reclassified from Accumulated Other Comprehensive Income to Net Income can differ from the estimate above due to market price changes. As of December 31, 2013, the maximum length of time that I&M is hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") exposure to variability in future cash flows to forecasted transaction is 12 months).

Credit Risk

AEPSC, on behalf of I&M, limits credit risk in the 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. AEPSC, on behalf of I&M, uses Moody's, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

When AEPSC, on behalf of I&M, uses standardized master agreements, these agreements may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an 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, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, I&M is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. I&M has not experienced a downgrade below investment grade. The following table represents: (a) I&M's fair values of such derivative contracts, (b) the amount of collateral I&M would have been required to post for all derivative and non-derivative contracts if its credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of December 31, 2013 and 2012:

	Liabilities for Derivative Contracts with Credit Downgrade Triggers	Amount of Collateral I&M Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities
		(in thousands)	
December 31, 2013	$ 390	$ 1,863	$ 1,722
December 31, 2012	1,483	2,540	2,411

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 in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by I&M and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering I&M's contractual netting arrangements as of December 31, 2013 and 2012:

	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
		(in thousands)	
December 31, 2013	$ 13,326	$ -	$ 12,594
December 31, 2012	53,499	1,252	40,240

9. 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 as of December 31, 2013 and 2012 are summarized in the following table:

December 31,			
2013		2012	
Book Value	Fair Value	Book Value	Fair Value
(in thousands)			
$ 1,861,476	$ 1,996,837	$ 1,833,290	$ 2,144,652

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. See "Nuclear Trust Funds" section of Note 1.

The following is a summary of nuclear trust fund investments as of December 31, 2013 and 2012:

	December 31,					
	2013			2012		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in thousands)					
Cash and Cash Equivalents	$ 18,804	$ -	$ -	$ 16,783	$ -	$ -
Fixed Income Securities:						
United States Government	608,875	26,114	(3,824)	647,918	58,268	(747)
Corporate Debt	36,782	2,450	(1,123)	35,399	4,903	(1,352)
State and Local Government	254,638	748	(370)	270,090	1,006	(863)
Subtotal Fixed Income Securities	900,295	29,312	(5,317)	953,407	64,177	(2,962)
Equity Securities - Domestic	1,012,511	505,538	(81,677)	735,582	284,599	(76,557)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,931,610	$ 534,850	$ (86,994)	$ 1,705,772	$ 348,776	$ (79,519)

The following table provides the securities activity within the decommissioning and SNF trusts for the years ended December 31, 2013 and 2012:

	Years Ended December 31, 2013	2012
	(in thousands)	
Proceeds from Investment Sales	$ 858,406	$ 987,550
Purchases of Investments	909,998	1,045,422
Gross Realized Gains on Investment Sales	18,326	24,605
Gross Realized Losses on Investment Sales	8,108	8,881

The adjusted cost of fixed income securities was $872 million and $889 million as of December 31, 2013 and 2012, respectively. The adjusted cost of equity securities was $506 million and $451 million as of December 31, 2013 and 2012, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2013 was as follows:

	Fair Value of Fixed Income Securities
	(in thousands)
Within 1 year	$ 79,100
1 year – 5 years	383,623
5 years – 10 years	187,800
After 10 years	249,772
Total	$ 900,295

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 of December 31, 2013 and 2012. 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, 2013

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (b)	$ 561	$ 38,667	$ 8,205	$ (20,766)	$ 26,667
Derivative Instrument Assets – Hedges					
Cash Flow Hedges – Commodity (a)	-	234	-	(18)	216
Other Special Funds					
Cash and Cash Equivalents (c)	8,082	-	-	10,722	18,804
Fixed Income Securities:					
United States Government	-	608,875	-	-	608,875
Corporate Debt	-	36,782	-	-	36,782
State and Local Government	-	254,638	-	-	254,638
Subtotal Fixed Income Securities	-	900,295	-	-	900,295
Equity Securities – Domestic (d)	1,012,511	-	-	-	1,012,511
Total Other Special Funds	1,020,593	900,295	-	10,722	1,931,610
Total Assets	$ 1,021,154	$ 939,196	$ 8,205	$ (10,062)	$ 1,958,493
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 475	$ 35,061	$ 1,041	$ (22,796)	$ 13,781
Derivative Instrument Liabilities - Hedges					
Cash Flow Hedges – Commodity (a)	-	212	-	(18)	194
Total Liabilities	$ 475	$ 35,273	$ 1,041	$ (22,814)	$ 13,975

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2012

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (b)	$ 2,858	$ 120,242	$ 11,717	$ (84,474)	$ 50,343
Derivative Instrument Assets – Hedges					
Cash Flow Hedges – Commodity (a)	-	330	-	(130)	200
Other Special Funds					
Cash and Cash Equivalents (c)	6,508	-	-	10,275	16,783
Fixed Income Securities:					
United States Government	-	647,918	-	-	647,918
Corporate Debt	-	35,399	-	-	35,399
State and Local Government	-	270,090	-	-	270,090
Subtotal Fixed Income Securities	-	953,407	-	-	953,407
Equity Securities – Domestic (d)	735,582	-	-	-	735,582
Total Other Special Funds	742,090	953,407	-	10,275	1,705,772
Total Assets	$ 744,948	$ 1,073,979	$ 11,717	$ (74,329)	$ 1,756,315
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 1,346	$ 110,621	$ 4,176	$ (91,183)	$ 24,960
Derivative Instrument Liabilities - Hedges					
Cash Flow Hedges:					
Commodity (a)	-	1,061	-	(130)	931
Interest Rate/Foreign Currency	-	19,524	-	-	19,524
Total Derivative Instrument Liabilities – Hedges	-	20,585	-	(130)	20,455
Total Liabilities	$ 1,346	$ 131,206	$ 4,176	$ (91,313)	$ 45,415

(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 have been no transfers between Level 1 and Level 2 during the years ended December 31, 2013 and 2012.

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, 2013	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2012	$ 7,541
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(2,466)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	390
Transfers into Level 3 (d) (e)	911
Transfers out of Level 3 (e) (f)	(637)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	1,425
Balance as of December 31, 2013	$ 7,164

Year Ended December 31, 2012	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2011	$ 1,263
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets (a) (b)	(3,554)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	13
Purchases, Issuances and Settlements (c)	7,734
Transfers into Level 3 (d) (e)	860
Transfers out of Level 3 (e) (f)	(1,144)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	2,369
Balance as of December 31, 2012	$ 7,541

(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) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Represents existing assets or liabilities that were previously categorized as Level 3.
(g) 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.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of December 31, 2013 and 2012:

Significant Unobservable Inputs
December 31, 2013

	Fair Value		Valuation	Significant	Forward Price Range	
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High
	(in thousands)					
Energy Contracts	$ 6,348	$ 651	Discounted Cash Flow	Forward Market Price	$ 13.04	$ 80.50
FTRs	1,857	390	Discounted Cash Flow	Forward Market Price	(5.10)	10.44
Total	$ 8,205	$ 1,041				

Significant Unobservable Inputs
December 31, 2012

	Fair Value		Valuation	Significant	Forward Price Range	
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High
	(in thousands)					
Energy Contracts	$ 10,516	$ 2,693	Discounted Cash Flow	Forward Market Price	$ 9.40	$ 68.80
FTRs	1,201	1,483	Discounted Cash Flow	Forward Market Price	(3.21)	14.79
Total	$ 11,717	$ 4,176				

(a) Represents market prices in dollars per MWh.

10. INCOME TAXES

The details of income taxes as reported are as follows:

	Years Ended December 31, 2013	2012
	(in thousands)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ (52,836)	$ (5,100)
Deferred	128,809	51,796
Deferred Investment Tax Credits	(4,931)	(4,502)
Total	71,042	42,194
Charged (Credited) to Nonoperating Income, Net:		
Current	3,768	(4,157)
Deferred	295	1,340
Total	4,063	(2,817)
Total Income Taxes	$ 75,105	$ 39,377

Shown below 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, 2013	2012
	(in thousands)	
Net Income	$ 177,504	$ 118,457
Income Tax Expense	75,105	39,377
Pretax Income	$ 252,609	$ 157,834
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 88,413	$ 55,242
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
Depreciation	10,057	8,659
Investment Tax Credits, Net	(4,931)	(4,502)
State and Local Income Taxes, Net	(882)	(1,559)
Removal Costs	(9,432)	(5,490)
AFUDC	(10,555)	(7,218)
Other	2,435	(5,755)
Income Tax Expense	$ 75,105	$ 39,377
Effective Income Tax Rate	29.7 %	24.9 %

The following table shows elements of the net deferred tax liability and significant temporary differences:

	December 31, 2013	2012
	(in thousands)	
Deferred Tax Assets	$ 845,489	$ 832,086
Deferred Tax Liabilities	(2,046,671)	(1,868,399)
Net Deferred Tax Liabilities	$ (1,201,182)	$ (1,036,313)
Property Related Temporary Differences	$ (391,452)	$ (373,831)
Amounts Due from Customers for Future Federal Income Taxes	(39,137)	(37,633)
Deferred State Income Taxes	(139,031)	(115,479)
Deferred Income Taxes on Other Comprehensive Loss	9,023	14,734
Accrued Nuclear Decommissioning	(553,794)	(475,223)
Net Operating Loss Carryforward	15,690	31,233
Regulatory Assets	(59,008)	(88,696)
All Other, Net	(43,473)	8,582
Net Deferred Tax Liabilities	$ (1,201,182)	$ (1,036,313)

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 tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

Federal and State Income Tax Audit Status

I&M and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2011. The Internal Revenue Service (IRS) examination of years 2009 and 2010 started in October 2011 and was completed in the second quarter of 2013. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, I&M accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

I&M and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns. I&M and other AEP subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income.

Net Income Tax Operating Loss Carryforward

In 2011, I&M recognized a federal net income tax operating loss of $125 million driven primarily by bonus depreciation, pension plan contributions and other book versus tax temporary differences. I&M also had a state net income tax operating loss carryforward in Indiana of $50.4 million that expires in 2033.

As a result, I&M recognized deferred federal and/or state and local income tax benefits in 2012 and/or 2013. At the end of 2013, I&M had $13 million of unrealized federal net operating loss carryforward. Management anticipates future taxable income will be sufficient to realize the remaining net income tax operating loss tax benefits before the federal carryforward expires after 2032. Management also anticipates future taxable income will be sufficient to realize the remaining state net income tax operating loss tax benefits before the state carryforward expires in 2033.

Tax Credit Carryforward

Federal net income tax operating losses sustained in 2011 and 2009, along with lower federal taxable income in 2010, resulted in unused federal income tax credits. As of December 31, 2013, I&M had federal tax credit carryforwards of $2.6 million which will expire in the years 2029 through 2032.

I&M anticipates future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused.

Uncertain Tax Positions

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

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

	Years Ended December 31, 2013	2012
	(in thousands)	
Interest Expense	$ -	$ 1,355
Interest Income	597	-

The amounts accrued for payment of interest and penalties were $957 thousand and $1.3 million as of December 31, 2013 and 2012, respectively.

The reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2013	2012
	(in thousands)	
Balance as of January 1,	$ 15,085	$ 14,071
Increase - Tax Positions Taken During a Prior Period	-	2,266
Decrease - Tax Positions Taken During a Prior Period	(11,921)	(1,252)
Increase - Tax Positions Taken During the Current Year	-	-
Decrease - Tax Positions Taken During the Current Year	-	-
Decrease - Settlements with Taxing Authorities	-	-
Decrease - Lapse of the Applicable Statute of Limitations	-	-
Balance as of December 31,	$ 3,164	$ 15,085

Management believes that there will be no significant net increase or decrease in unrecognized benefits within 12 months of the reporting date. The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $1.2 million and $1.2 million for 2013 and 2012, respectively.

Federal Tax Legislation

The American Taxpayer Relief Act of 2012 (the 2012 Act) was enacted in January 2013. Included in the 2012 Act was a one-year extension of 50% bonus depreciation. The 2012 Act also retroactively extended the life of research and development, employment and several energy tax credits, which expired at the end of 2011. The enacted provisions did not materially impact net income or financial condition but had a favorable impact on cash flows in 2013.

Federal Tax Regulations

In 2013, the U.S. Treasury Department issued final and re-proposed regulations regarding the deduction and capitalization of expenditures related to tangible property, effective for the tax years beginning in 2014. In addition, the IRS issued Revenue Procedures under the Industry Issue Resolutions program that provides specific guidance for the implementation of the regulations for the electric utility industry. The impact of these final regulations is not material to net income or financial condition but will result in an approximate $10 million reduction to cash flows in 2014.

State Tax Legislation

Legislation was passed by the state of Indiana in May 2011 enacting a phased reduction in corporate income tax rate from 8.5% to 6.5%. The 8.5% Indiana corporate income tax rate will be reduced 0.5% each year beginning after June 30, 2012 with the final reduction occurring in years beginning after June 30, 2015.

During the third quarter of 2013, it was determined that the state of West Virginia had achieved certain minimum levels of shortfall reserve funds. As a result, the West Virginia corporate tax rate will be reduced from 7.0% to 6.5% in 2014. The enacted provisions will not materially impact net income, cash flows or financial condition.

11. LEASES

Leases of property, plant and equipment are for remaining periods up to 11 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

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

	Years Ended December 31, 2013	2012
	(in thousands)	
Net Lease Expense on Operating Leases	$ 95,606	$ 95,509
Amortization of Capital Leases	94,283	130,239
Interest on Capital Leases	44,089	8,477
Total Lease Rental Costs	$ 233,978	$ 234,225

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

	December 31, 2013	2012
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 18,324	$ 19,102
Other Property, Plant and Equipment	287,070	198,762
Total Property, Plant and Equipment	305,394	217,864
Accumulated Amortization	15,357	13,154
Net Property, Plant and Equipment Under Capital Leases	$ 290,037	$ 204,710
Obligations Under Capital Leases:		
Noncurrent	$ 147,450	$ 115,315
Current	142,580	89,395
Total Obligations Under Capital Leases	$ 290,030	$ 204,710

Future minimum lease payments consisted of the following as of December 31, 2013:

	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2014	$ 159,157	$ 98,819
2015	87,670	95,935
2016	48,267	90,431
2017	15,382	84,624
2018	4,338	83,525
Later Years	10,244	341,472
Total Future Minimum Lease Payments	325,058	$ 794,806
Less Estimated Interest Element	35,028	
Estimated Present Value of Future Minimum Lease Payments	$ 290,030	

Master Lease Agreements

I&M leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, I&M is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of December 31, 2013, I&M's maximum potential loss for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term is $2.5 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 does not guarantee its debt. I&M's future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2013 are as follows:

	Future Minimum Lease Payments (in thousands)
2014	$ 73,854
2015	73,854
2016	73,854
2017	73,854
2018	73,854
Later Years	295,416
Total Future Minimum Lease Payments	$ 664,686

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as an operating lease. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M intends to renew the lease for the full lease term of twenty years via the renewal options. I&M's future minimum lease obligation is $13 million for the remaining railcars as of December 31, 2013. The obligation is included in the future minimum lease payments schedule earlier in this note.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 83% of the projected fair value of the equipment under the current five-year lease term to 77% at the end of the 20-year term. I&M assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is approximately $9 million 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 Leases

In September 2009, I&M entered into a sale-and-leaseback transaction for $102.3 million with DCC Fuel LLC (DCC) to lease nuclear fuel for the Cook Plant. DCC was 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. I&M made the final payment on the lease in October 2013 and the lease terminated.

In April 2010, I&M entered into a sale-and-leaseback transaction for $84.6 million with DCC Fuel II LLC (DCC II) to lease nuclear fuel for the Cook Plant. DCC II is a single-lessee leasing arrangement with one asset and was formed for the sole purpose of acquiring, owning and leasing nuclear fuel to I&M. The lease has a fixed rate of 4% and is a capital lease with a term of 54 months. I&M makes payments on the lease semi-annually in April and October. Payments began in October 2010.

In December 2010, I&M entered into a sale-and-leaseback transaction for $67.9 million with DCC Fuel III LLC (DCC III) to lease nuclear fuel for the Cook Plant. DCC III was 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 had a variable rate and was a capital lease. Management chose to terminate the lease early. I&M made the final payment in October 2013.

In November 2011, I&M entered into a sale-and-leaseback transaction for $110 million with DCC Fuel IV LLC (DCC IV) to lease nuclear fuel for the Cook Plant. DCC IV is a single-lessee leasing arrangement with one asset and was formed for the sole purpose of acquiring, owning and leasing nuclear fuel to I&M. The lease has a variable rate for $65 million and a fixed rate of 2.12% for $45 million. The lease is a capital lease with a term of 54 months. I&M makes payments on the lease quarterly in February, May, August and November. Payments began in February 2012.

In April 2012, I&M entered into a sale-and-leaseback transaction for $110 million with DCC Fuel V LLC (DCC V). DCC V 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 2012.

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. Payments began in August 2013.

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

	Future Minimum Lease Payments (in thousands)
2014	$ 42,567
2015	32,198
2016	26,888
2017	5,762
2018	2,398
Total Future Minimum Lease Payments	$ 109,813

The nuclear fuel leases are recorded net in Utility Plant. The capital lease obligations and future minimum lease payments for the nuclear fuel leases are included in the tables above.

12. FINANCING ACTIVITIES

Long-term Debt

There are certain limitations on establishing liens against I&M's assets under indentures. None of the long-term debt obligations of I&M have been guaranteed or secured by AEP or any of its affiliates.

The following details long-term debt outstanding as of December 31, 2013 and 2012:

Type of Debt	Maturity	Weighted Average Interest Rate as of December 31, 2013	Interest Rate Ranges as of December 31, 2013	Interest Rate Ranges as of December 31, 2012	Outstanding as of December 31, 2013	Outstanding as of December 31, 2012
					(in thousands)	
Senior Unsecured Notes	2014-2037	5.80%	3.20%-7.00%	5.05%-7.00%	$ 1,250,000	$ 1,175,000
Pollution Control Bonds (a)	2013-2025 (b)	3.79%	0.04%-6.25%	0.11%-6.25%	227,000	267,000
Spent Nuclear Fuel Liability (c)					265,391	265,249
Other Long-term Debt (d)	2015-2025	2.35%	1.67%-6.00%	1.72%-6.00%	123,281	130,430
Unamortized Discount, Net					(4,196)	(4,389)
Total Long-term Debt					$ 1,861,476	$ 1,833,290

(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 and repayment purposes based on the mandatory redemption date.

(c) Spent nuclear fuel obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see "SNF Disposal" section of Note 5).

(d) In 2012, I&M issued a $110 million three-year credit facility to be used for general corporate purposes.

Long-term debt outstanding as of December 31, 2013 is payable as follows:

	(in thousands)
2014	$ 187,702
2015	220,201
2016	1,360
2017	1,479
2018	1,570
After 2018	1,453,360
Principal Amount	1,865,672
Unamortized Discount, Net	(4,196)
Total Long-term Debt Outstanding	$ 1,861,476

As of December 31, 2013, trustees held, on behalf of I&M, $40 million of its reacquired Pollution Control Bonds.

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.

Federal Power Act

The Federal Power Act prohibits I&M from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." The term "capital account" is not defined in the Federal Power Act or its regulations. Management understands "capital account" to mean the book value of the common stock.

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

None of these restrictions limit the ability of I&M to pay dividends out of retained earnings.

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, I&M must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. As of December 31, 2013, $12 million of I&M's retained earnings have restrictions related to the payment of dividends to Parent.

Utility Money Pool – 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 amount of outstanding loans to the Utility Money Pool as of December 31, 2013 and 2012 is included in Notes Receivable from Associated Companies on the balance sheets. I&M's money pool activity and its corresponding authorized borrowing limits for the years ended December 31, 2013 and 2012 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	Loans to the Utility Money Pool as of December 31,	Authorized Short-term Borrowing Limit
			(in thousands)			
2013	$ 23,135	$ 390,446	$ 8,308	$ 255,891	$ 42,403	$ 500,000
2012	-	348,852	-	189,345	103,619	500,000

Maximum, minimum and average interest rates for funds borrowed from and loaned to the Utility Money Pool for the years ended December 31, 2013 and 2012 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
2013	0.36%	0.35%	0.43%	0.24%	0.36%	0.32%
2012	-%	-%	-%	0.39%	-%	0.46%

Interest expense related to the Utility Money Pool is included in Interest on Debt to Associated Companies. I&M incurred interest expense for borrowing from the Utility Money Pool of $70 thousand for the year ended December 31, 2013.

Interest income related to the Utility Money Pool is included in Interest and Dividend Income. I&M earned interest income for amounts advance to the Utility Money Pool of $879 thousand and $901 thousand for the years ended December 31, 2013 and 2012, respectively.

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 5.

Sale of Receivables – AEP Credit

Under a sale of receivables arrangement, I&M sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and I&M's uncollectible accounts experience. I&M manages and services its customer accounts receivable sold.

In June 2013, AEP Credit amended its receivables securitization agreement to extend through June 2014. The agreement provides a commitment of $700 million from bank conduits to purchase receivables. AEP Credit amended a commitment of $385 million to now expire in June 2014. The remaining commitment of $315 million expires in June 2015. AEP Credit intends to extend or replace the agreement expiring in June 2014 on or before its maturity.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement as of December 31, 2013 and 2012 was $139.3 million and $123.4 million, respectively.

The fees paid to AEP Credit for customer accounts receivable sold were $6.5 million and $6.1 million for the years ended December 31, 2013 and 2012, respectively.

I&M's proceeds on the sale of receivables to AEP Credit were $1.5 billion and $1.3 billion for the years ended December 31, 2013 and 2012, respectively.

13. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "AEP System Tax Allocation Agreement" section of Note 10 in addition to "Utility Money Pool – AEP System" and "Sale of Receivables – AEP Credit" sections of Note 12.

Interconnection Agreement

In accordance with management's December 2010 announcement and October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated.

APCo, I&M, KPCo, OPCo and AEPSC were parties to the Interconnection Agreement which defined the sharing of costs and benefits associated with their generating plants. This sharing was based upon each AEP utility subsidiary's MLR and was calculated monthly on the basis of each AEP utility subsidiary's maximum peak demand in relation to the sum of the maximum peak demands of all four AEP utility subsidiaries during the preceding 12 months.

Effective January 1, 2014, the FERC approved the creation of the Power Coordination Agreement among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Also effective January 1, 2014, the FERC approved the Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent to address open commitments related to the termination of the Interconnection Agreement and responsibilities to PJM. See "Corporate Separation and Termination of Interconnection Agreement" section of Note 3.

Prior to January 1, 2014, power, natural gas and risk management activities were conducted by AEPSC and profits and losses were allocated under the SIA to members of the Interconnection Agreement, PSO and SWEPCo. Risk management activities involved the purchase and sale of power and natural gas under physical forward contracts at fixed and variable prices. In addition, the risk management of power, and to a lesser extent natural gas contracts, included exchange traded futures and options and OTC options and swaps. The majority of these transactions represented physical forward contracts in the AEP System's traditional marketing area and were typically settled by entering into offsetting contracts. In addition, AEPSC entered into transactions for the purchase and sale of power and natural gas options, futures and swaps, and for the forward purchase and sale of power outside of the AEP System's traditional marketing area.

Operating Agreement

PSO, SWEPCo and AEPSC are parties to the Operating Agreement which was approved by the FERC. The Operating Agreement requires PSO and SWEPCo to maintain adequate annual planning reserve margins and requires that capacity in excess of the required margins be made available for sale to other operating companies as capacity commitments. Parties are compensated for energy delivered to recipients based upon the deliverer's incremental cost plus a portion of the recipient's savings realized by the purchaser that avoids more costly alternatives.

System Integration Agreement (SIA)

The SIA provides for the integration and coordination of AEP East Companies' and AEP West Companies' zones. This includes joint dispatch of generation within the AEP System and the distribution, between the two zones, of costs and benefits associated with the transfers of power between the two zones (including sales to third parties and risk management and trading activities). The SIA is designed to function as an umbrella agreement in addition to the Interconnection Agreement (prior to January 1, 2014) and the Operating Agreement, each of which controls the distribution of costs and benefits within a zone.

Power generated, allocated or provided under the Interconnection Agreement or the Operating Agreement is primarily sold to customers at rates approved by the public utility commission in the jurisdiction of sale.

Under both the Interconnection Agreement and the Operating Agreement, power generated that is not needed to serve the AEP System's native load is sold in the wholesale market by AEPSC on behalf of the generating subsidiary.

Affiliated Revenues and Purchases

The following table shows the revenues derived from sales under the Interconnection Agreement, direct sales to affiliates, net transmission agreement sales and other revenues for the years ended December 31, 2013 and 2012:

Related Party Revenues	Years Ended December 31, 2013	2012
	(in thousands)	
Sales under Interconnection Agreement	$ 218,164	$ 265,923
Direct Sales to West Affiliates	391	218
Transmission Agreement and Transmission Coordination Agreement Sales	(681)	758
Other Revenues	1,525	1,509

The following table shows the purchased power expenses incurred for purchases under the Interconnection Agreement and from affiliates for the years ended December 31, 2013 and 2012:

Related Party Purchases	Years Ended December 31, 2013	2012
	(in thousands)	
Purchases under Interconnection Agreement	$ 181,688	$ 147,502
Direct Purchases from West Affiliates	3	36
Purchases from AEGCo	251,518	238,866

System Transmission Integration Agreement

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP East Companies' and AEP West Companies' zones. Similar to the SIA, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the Transmission Agreement (TA) and the Transmission Coordination Agreement (TCA). The System Transmission Integration Agreement contains two service schedules that govern:

- The allocation of transmission costs and revenues.
- The allocation of third-party transmission costs and revenues and AEP System dispatch costs.

The System Transmission Integration Agreement anticipates that additional service schedules may be added as circumstances warrant.

APCo, I&M, KGPCo, KPCo, OPCo and WPCo are parties to the TA which defines how transmission costs through PJM OATT are allocated among the AEP East Companies, KGPCo and WPCo on a 12-month average coincident peak basis. I&M's net charges recorded for the years ended December 31, 2013 and 2012 related to the TA were $19.9 million and $5.7 million, respectively. The charges are recorded in Operation Expenses.

PSO, SWEPCo and AEPSC are parties to the TCA, dated January 1, 1997, revised 1999 and 2011, as restated and amended, by and among PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two AEP utility subsidiaries. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the parties to the agreement. This includes the performance of transmission planning studies, the interaction of such companies with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such a tariff.

Unit Power Agreements (UPA)

UPA between AEGCo and I&M

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. Subsequently, I&M assigns 30% of the power to KPCo. See the "UPA between AEGCo and KPCo" section below. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

UPA between AEGCo and KPCo

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

Cook Coal Terminal

On August 1, 2013, OPCo transferred ownership of Cook Coal Terminal to AEGCo. Cook Coal Terminal performs coal transloading services at cost for I&M. I&M recorded costs from AEGCo of $6.8 million for transloading services in Fuel Stock for the year ended December 31, 2013. I&M recorded costs from OPCo of $15.6 million and $32.6 million for transloading services in Fuel Stock for the years ended December 31, 2013 and 2012, respectively. Amounts purchased from OPCo by I&M included $7.3 million and $14.5 million in 2013 and 2012, respectively, purchased on behalf of AEGCo for Rockport Plant through July 31, 2013.

Cook Coal Terminal also performs railcar maintenance services at cost for I&M. AEGCo billed I&M $1.1 million for the year ended December 31, 2013 for railcar maintenance services. OPCo billed I&M $1.3 million and $3.3 million for the years ended December 31, 2013 and 2012, respectively, for railcar maintenance services. These amounts include $608 thousand and $1.5 million in 2013 and 2012, respectively, purchased by I&M on behalf of AEGCo for Rockport Plant through July 31, 2013. I&M recorded the cost of the railcar maintenance services in Fuel Stock.

SWEPCo Railcar Facility

SWEPCo operates a railcar maintenance facility in Alliance, Nebraska. The facility performs maintenance on its own railcars as well as railcars belonging to I&M. SWEPCo billed I&M $873 thousand and $1.6 million for railcar services provided in 2013 and 2012, respectively. I&M's costs are recorded in Fuel Stock.

I&M Barging, Urea Transloading and Other Services

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NOx emissions at certain generation plants in the AEP System. I&M recorded revenues from barging, transloading and other services for affiliates of $113.9 million and $115.6 million for the years ended December 31, 2013 and 2012, respectively, in Revenues from Nonutility Operations.

Services Provided by AEP River Operations LLC

AEP River Operations LLC provides services for barge towing, chartering and general and administrative expenses to I&M. For the years ended December 31, 2013 and 2012, I&M recorded expenses of $24 million each year for these activities as Expenses of Nonutility Operations.

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 $2.5 million and $1.3 million as capital or maintenance expenses depending on the nature of the services received for the years ended December 31, 2013 and 2012, respectively. These billings are recoverable from customers.

Affiliate Railcar Agreement

The AEP East Companies, AGR, PSO and SWEPCo have an agreement providing for the use of each other's leased or owned railcars when available. The agreement specifies that the company using the railcar will be billed, at cost, by the company furnishing the railcar. I&M recorded the costs or reimbursements as costs or reduction of costs, respectively, in Fuel Stock on the balance sheets and such costs are recoverable from customers. The following table shows the net effect of the railcar agreement on the balance sheets:

Years Ended December 31,	AGR	APCo	OPCo	PSO	SWEPCo
			(in thousands)		
Payment of Costs:					
2013	$ (391)	$ 507	$ -	$ 195	$ 854
2012	-	148	889	48	843
Reimbursement of Costs:					
2013	33	-	-	595	1,395
2012	-	2	170	322	1,468

OVEC

AEP, OPCo and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2013, AEP's and OPCo's ownership and investment in OVEC were as follows:

	December 31, 2013	
Company	**Ownership**	**Investment**
		(in thousands)
AEP	39.17 %	$ 3,978
OPCo	4.30 %	430
Total	43.47 %	$ 4,408

OVEC's owners, along with APCo and I&M, are members to an intercompany power agreement. Participants of this agreement are entitled to receive and obligated to pay for all OVEC generating capacity, approximately 2,200 MWs, in proportion to their respective power participation ratios. The aggregate power participation ratio of certain AEP utility subsidiaries, including APCo, I&M and OPCo, is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and provide a return on capital. The intercompany power agreement expires in June 2040.

AEP, OPCo and other nonaffiliated owners authorized environmental investments related to their ownership interests and OVEC's Board of Directors authorized capital expenditures totaling $1.4 billion in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at OVEC's two generation plants. These environmental projects were funded through debt issuances. As of December 31, 2013, both generation plants were operating with new environmental controls.

Purchased Power from OVEC

I&M paid $52.2 million and $49.2 million for power purchased from OVEC for the years ended December 31, 2013 and 2012, respectively. The amounts are recoverable from customers and are included in Operation Expenses.

Sales and Purchases of Property

I&M had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters, transformers and transmission property. There were no gains or losses recorded on the transactions. The following table shows the sales and purchases, recorded in Utility Plant at net book value, for the years ended December 31, 2013 and 2012:

	Years Ended December 31,	
	2013	**2012**
	(in thousands)	
Sales	$ 5,031	$ 3,296
Purchases	964	285

Intercompany Billings

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

AEPSC

AEPSC provides certain managerial and professional services to AEP's subsidiaries. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEPSC and its billings are subject to regulation by the FERC. I&M's total billings from AEPSC were $119.3 million and $127.2 million for the years ended December 31, 2013 and 2012, respectively.

14. 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 annual composited depreciation rates by functional class:

Year	Nuclear	Steam	Hydro	Transmission	Distribution	General
			(in percentages)			
2013	1.7	2.4	2.7	1.5	2.8	4.9
2012	1.3	2.4	2.5	1.5	2.5	9.6

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

Asset Retirement Obligations (ARO)

I&M records ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for the retirement of certain ash disposal facilities and asbestos removal. I&M records ARO for the decommissioning of the Cook Plant. I&M has identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since I&M plans to use 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, 2013 and 2012, I&M's ARO liability for nuclear decommissioning of the Cook Plant was $1.2 billion and $1.2 billion, respectively. As of December 31, 2013 and 2012, the fair value of the assets that are legally restricted for purposes of settling decommissioning liabilities totaled $1.6 billion and $1.4 billion, respectively. These assets are included in Other Special Funds.

The following is a reconciliation of the 2013 and 2012 aggregate carrying amounts of ARO related to nuclear decommissioning, ash disposal facilities and asbestos removal:

Year	ARO at January 1,	Accretion Expense	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31,
			(in thousands)		
2013	$ 1,192,313	$ 72,658	$ (635)	$ (9,152)	$ 1,255,184
2012	1,013,122	53,848	(806)	126,149	1,192,313

Jointly-owned Electric Facilities

I&M has electric facilities that are jointly-owned with an affiliated company. Using its own financing, I&M is obligated to pay its share of the costs of any such jointly-owned facilities in the same proportion as its ownership interest. I&M's proportionate share of the operating costs associated with such 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:

			Company's Share as of December 31, 2013		
Facility	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
Rockport Generating Plant, Unit 1 (a)	Coal	50.0 %	$ 797,485	$ 54,577	$ 471,787

			Company's Share as of December 31, 2012		
Facility	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
Rockport Generating Plant, Unit 1 (a)	Coal	50.0 %	$ 762,737	$ 55,420	$ 456,436

(a) Operated by I&M.

15. SUSTAINABLE COST REDUCTIONS

In April 2012, management initiated a process to identify strategic repositioning opportunities and efficiencies that will result in sustainable cost savings. Management selected a consulting firm to facilitate an organizational and process evaluation and a second firm to evaluate current employee benefit programs. The process resulted in involuntary severances and was completed by the end of the first quarter of 2013. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

I&M recorded charges of $5.7 million in 2012 primarily related to severance benefits as a result of the sustainable cost reductions initiative.

I&M's sustainable cost reduction activity for the year ended December 31, 2013 is described in the following table:

Balance as of December 31, 2012	Expense Allocation from AEPSC	Incurred	Settled	Adjustments	Remaining Balance as of December 31, 2013
		(in thousands)			
$ 1,357	$ 736	$ -	$ (1,690)	$ (381)	$ 22

These expenses, net of adjustments, relate primarily to severance benefits. Management does not expect additional costs to be incurred related to this initiative.

16. 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 year ended December 31, 2013, 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
					(dollars in thousands)			
East Busco Station	Distribution	Churubusco, IN	363	$ 5,489	584	$ 39(a)	592	$ 11(b)

(a) This amount would have been recorded in Account 584.1 in accordance with FERC Order No. 784.
(b) 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 2013/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	7,192,203,397	7,192,203,397
4	Property Under Capital Leases	22,377,299	22,377,299
5	Plant Purchased or Sold		
6	Completed Construction not Classified	238,914,562	238,914,562
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	7,453,495,258	7,453,495,258
9	Leased to Others		
10	Held for Future Use	5,651,068	5,651,068
11	Construction Work in Progress	427,164,224	427,164,224
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	7,886,310,550	7,886,310,550
14	Accum Prov for Depr, Amort, & Depl	3,567,283,475	3,567,283,475
15	Net Utility Plant (13 less 14)	4,319,027,075	4,319,027,075
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	3,426,398,251	3,426,398,251
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	141,524,886	141,524,886
22	Total In Service (18 thru 21)	3,567,923,137	3,567,923,137
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	-639,662	-639,662
29	Amortization		
30	Total Held for Future Use (28 & 29)	-639,662	-639,662
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	3,567,283,475	3,567,283,475

This Page Intentionally Left Blank

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 2013/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	130,637,439	115,557,182
4	Allowance for Funds Used during Construction	1,158,027	8,312,735
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	131,795,466	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)	119,118,515	382,686,358
10	SUBTOTAL (Total 8 & 9)	119,118,515	
11	Spent Nuclear Fuel (120.4)	224,950,629	372,428,305
12	Nuclear Fuel Under Capital Leases (120.6)	176,065,156	211,553,500
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	338,796,232	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	313,133,534	
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)		

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 2013/Q4

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
	202,892,386	43,302,235	3
	9,470,617	145	4
			5
		43,302,380	6
			7
			8
	498,981,806	2,823,067	9
		2,823,067	10
	71,966,603	525,412,331	11
125,765,877		261,852,779	12
-259,908,244	71,966,603	526,737,873	13
		306,652,684	14
			15
			16
			17
			18
			19
			20
			21
			22

FOOTNOTE DATA

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 - $287,428,306

Reclassification of nuclear fuel from owned to leased due to sale/leaseback with third party - $211,553,500

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

Retirement of spent fuel

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

Includes 2012 costs in connection with nuclear fuel leases:

Finance charges	$6,681,715
Administrative and Legal	$ 51,000

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

Reclassification of $211,553,500 of nuclear fuel from owned to leased due to sale/leaseback with third party

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

Includes 2013 costs in connection with nuclear leases:

Finance charges	$4,714,710

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

Retirement of spent fuel

This Page Intentionally
Left Blank

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, 2013

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	119,791,765	13,467,761
5	TOTAL Intangible Plant	**139,775,289**	**13,467,761**
6	2. PRODUCTION PLANT		
7	Steam Production Plant		
8	310.1 Land	11,323,112	0
9	310.2 Land Rights	222,069	0
10	311 Structures and Improvements	152,602,902	2,838,488
11	312 Boiler Plant Equipment	925,350,920	31,967,255
12	313 Engines and Engine-Driven Generators	0	0
13	314 Turbogenerator Units	188,363,868	9,905,392
14	315 Accessory Electric Equipment	88,121,410	437,988
15	316 Miscellaneous Power Plant Equipment	31,200,301	266,394
16	317 Asset Retirement Costs for Steam Production	25,867,785	6,551,046
17	TOTAL Steam Production Plant	**1,423,052,367**	**51,966,563**
18	Nuclear Production Plant		
19	320.1 Land	1,879,588	0
20	320.2 Land Rights	0	0
21	321 Structures and Improvements	326,729,132	35,997,926
22	322 Reactor Plant Equipment	1,176,197,595	84,394,039
23	323 Turbogenerator Units	438,491,890	6,484,750
24	324 Accessory Electric Equipment	169,189,513	32,859,179

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, 2013

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
7,785,746	0	0	125,473,780	303	4
7,785,746	**0**	**0**	**145,457,304**		5
					6
					7
0	0	0	11,323,112	310.1	8
0	0	0	222,069	310.2	9
158,839	0	0	155,282,551	311	10
3,446,150	0	0	953,872,025	312	11
0	0	0	0	313	12
4,502,895	0	0	193,766,365	314	13
16,135	0		88,543,263	315	14
29,180	0	0	31,437,515	316	15
	0	0	32,418,831	317	16
8,153,199	**0**	**0**	**1,466,865,731**		17
					18
0	0	0	1,879,588	320.1	19
0	0	0	0	320.2	20
5,452,286	0	0	357,274,772	321	21
24,045,659	0	0	1,236,545,975	322	22
2,976,559	0	0	442,000,081	323	23
7,098,372	0	0	194,950,320	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, 2013

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	176,574,227	20,069,982
26	326 Asset Retirement Costs for Nuclear Production	277,556,034	0
27	TOTAL Nuclear Production Plant	**2,566,617,979**	**179,805,876**
28	Hydraulic Production Plant		
29	330.1 Land	510,360	0
30	330.2 Land Rights	196,186	0
31	331 Structures and Improvements	3,339,152	6,341
32	332 Reservoirs, Dams and Waterways	20,068,218	148,246
33	333 Water Wheels, Turbines and Generators	16,221,697	58,787
34	334 Accessory Electric Equipment	5,283,104	8,732
35	335 Miscellaneous Power Plant Equipment	2,214,665	16,816
36	336 Roads, Railroads and Bridges	853	0
37	337 Asset Retirement Costs for Hydraulic Production	242,144	0
38	TOTAL Hydraulic Production Plant	**48,076,379**	**238,922**
39	Other Production Plant		
40	340.1 Land	0	0
41	340.2 Land Rights	0	0
42	341 Structures and Improvements	0	0
43	342 Fuel Holders, Products and Accessories	0	0
44	343 Prime Movers	0	0
45	344 Generators	0	0
46	345 Accessory Electric Equipment	0	0
47	346 Miscellaneous Power Plant Equipment	0	0
48	347 Asset Retirement Costs for Other Production	0	0
49	TOTAL Other Production Plant	**0**	**0**
50	TOTAL Production Plant	**4,037,746,725**	**232,011,361**
51	3. TRANSMISSION PLANT		
52	350.1 Land	7,359,221	602,561
53	350.2 Land Rights	53,556,094	907,717
54	352 Structures and Improvements	21,016,777	157,350
55	353 Station Equipment	617,940,508	25,389,859
56	354 Towers and Fixtures	222,776,197	9,821,100
57	355 Poles and Fixtures	110,448,758	4,217,012
58	356 Overhead Conductors and Devices	236,513,641	4,126,645
59	357 Underground Conduit	2,326,337	0
60	358 Underground Conductors and Devices	5,740,173	365,538

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, 2013

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
3,067,151	0	0	193,577,058	325	25
0	0	0	277,556,034	326	26
42,640,027	**0**	**0**	**2,703,783,828**		27
					28
0	0	0	510,116	330.1	29
244	0	0	196,186	330.2	30
0	0	0	3,345,493	331	31
5,911	0	0	20,210,553	332	32
39,855	0	0	16,240,629	333	33
0	0	0	5,291,836	334	34
948	0	0	2,230,533	335	35
0	0	0	853	336	36
0	0	0	242,144	337	37
46,958	**0**	**0**	**48,268,343**		38
					39
0	0	0	0	340.1	40
0	0	0	0	340.2	41
0	0	0	0	341	42
0	0	0	0	342	43
0	0	0	0	343	44
0	0	0	0	344	45
0	0	0	0	345	46
0	0	0	0	346	47
0	0	0	0	347	48
0	**0**	**0**	**0**		49
50,840,184	**0**	**0**	**4,218,917,902**		50
					51
3,995	0	14,845	7,972,631	350.1	52
0	0	0	54,463,812	350.2	53
59,387	0	(8,339)	21,106,401	352	54
2,250,100	0	11,017	641,091,284	353	55
133,029	0	(69,944)	232,394,324	354	56
210,418	0	0	114,455,352	355	57
167,363	0	(59,219)	240,413,704	356	58
2	0	0	2,326,335	357	59
11,552	0	0	6,094,159	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, 2013

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	349,749	0
62	359.1 Asset Retirement Costs for Transmission Plant	0	0
63	TOTAL Transmission Plant	**1,278,027,455**	**45,587,782**
64	4. DISTRIBUTION PLANT		
65	360.1 Land	4,372,183	2,080,610
66	360.2 Land Rights	12,319,757	633,063
67	361 Structures and Improvements	9,199,460	659,513
68	362 Station Equipment	189,266,401	4,860,540
69	363 Storage Battery Equipment	5,486,659	2,242
70	364 Poles, Towers and Fixtures	222,640,683	7,257,579
71	365 Overhead Conductors and Devices	308,057,461	39,960,421
72	366 Underground Conduit	64,419,273	2,272,822
73	367 Underground Conductors and Devices	183,627,377	6,071,164
74	368 Line Transformers	269,714,188	12,705,626
75	368.1 Capacitors	0	0
76	369 Services	152,025,082	7,818,779
77	370 Meters	92,010,932	4,211,790
78	371 Installations on Customers' Premises	21,597,682	2,497,465
79	372 Leased Property on Customers' Premises	0	0
80	373 Street Lighting and Signal Systems	18,418,315	726,109
81	374 Asset Retirement Costs for Distribution Plant	0	0
82	TOTAL Distribution Plant	**1,553,155,453**	**91,757,723**
83	5. GENERAL PLANT		
84	389.1 Land	2,100,201	0
85	389.2 Lands Rights	178,388	0
86	390 Structures and Improvments	53,733,025	699,282
87	391 Office Furniture and Equipment	6,104,545	(83,800)
88	391.1 Computers / Computer Related Equipment	0	0
89	392 Transportation Equipment	0	0
90	393 Stores Equipment	40,849	2,137
91	394 Tools, Shop and Garage Equipment	10,158,261	204,706
92	395 Laboratory Equipment	338,061	0
93	396 Power Operated Equipment	544,766	0
94	397 Communication Equipment	26,457,396	13,775,146
95	398 Miscellaneous Equipment	7,983,274	146,590
96	SUBTOTAL	**107,638,766**	**14,744,061**

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, 2013

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	349,749	359	61
0	0	0	0	359.1	62
2,835,846	**0**	**(111,640)**	**1,320,667,751**		63
					64
656	0	0	6,451,731	360.1	65
0	0	0	12,953,226	360.2	66
17,298	0	0	9,841,675	361	67
588,895	0	127,640	193,665,686	362	68
0	0	0	5,488,901	363	69
954,557	0	0	228,943,705	364	70
4,438,719	0	0	343,579,163	365	71
73,593	0	0	66,618,502	366	72
466,846	0	0	189,231,695	367	73
4,344,851	0	0	278,074,963	368	74
0	0	0	0	368.1	75
780,179	0	135,298	159,198,980	369	76
7,821,160	0	(151,298)	88,250,264	370	77
471,158	0	0	23,623,989	371	78
0	0	0	0	372	79
212,045	0	0	18,932,379	373	80
0	0	0	0	374	81
20,169,957	**0**	**111,640**	**1,624,854,859**		82
					83
0	0	0	2,100,201	389.1	84
0	0	0	178,388	389.2	85
131,965	0	0	54,300,342	390	86
475,329	0	0	5,545,416	391	87
0	0	0	0	391.1	88
0	0	0	0	392	89
0	0	0	42,986	393	90
359,714	0	0	10,003,253	394	91
35,260	0	0	302,801	395	92
0	0	0	544,766	396	93
333,337	0	0	39,899,205	397	94
0	0	0	8,129,864	398	95
1,335,605	**0**	**0**	**121,047,222**		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, 2013

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	0
99	TOTAL General Plant	**107,811,687**	**14,744,061**
100	TOTAL (Accounts 101 and 106)	**7,116,516,609**	**397,568,688**
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)*	**7,116,516,609**	**397,568,688**

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, 2013

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	172,921	399.1	98
1,335,605	**0**	**0**	**121,220,143**		99
82,967,338	**0**	**0**	**7,431,117,959**		100
					101
0	0	0	0	102	102
0	0	0	0		103
0	0	0	0	103	104
82,967,338	**0**	**0**	**7,431,117,959**		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 31,2013

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)
207	53	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.

This Page Intentionally Left Blank

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 2013/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	Generating Plant Project Site (0110)	09/01/75		3,764,282
4				
5	Tanners Creek Generating Plant Units 1-4 (0105)	09/01/75		360,235
6				
7	Rockport Generating Plant Unit 1 (0111)	11/01/84		1,034,109
8				
9				
10	Items under $250,000			486,519
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Items under $250,000			5,923
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			5,651,068

FOOTNOTE DATA

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)	December 31, 2013

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, explai 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						

This Page Intentionally
Left Blank

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, 2013

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	TS/I&M/Purchase-Rebuild Maj Eq	1,212,102		
2	IM/IN/East Side Station D-Sta	3,594,263		17,465
3	Ds Im Ind-Ai Recloser Repl	1,010,020		
4	I&M Next Generation Radio Syst	1,716,960		
5	U1 Control Room HVAC Chiller	2,977,831		1,862,292
6	Ice Cndsr Glycol Chiller Rplmt	9,442,987		6,142,384
7	Cable Replacement	13,310,190		65,006
8	U1 Steam Generator WL Controls	3,062,667		9,128,826
9	U2 SG Water Level Controls	4,067,951		2,701,821
10	Unit 1 Refueling Equipment	4,255,286		6,437,488
11	Unit 2 Refueling Equip Rpl	3,283,491		6,724,123
12	U2 East CTS Hx Replacement	2,142,013		4,688,213
13	U1 East CTS Hx Replacement	2,537,238		8,194,372
14	U2 Feedwater Htrs HP	21,624,913		21,521,142
15	U1 HP FW Heaters Replac	12,497,543		28,482,197
16	Cyber Attacks Process LAN	3,683,138		
17	CK U1 Sec Sys Wtr Chem Upgrade	13,479,890		4,261,476
18	U2 Sec Sys Wtr Chem Upgrade	12,437,875		2,919,503
19	TSC and North Access Project	1,827,169		9,765,652
20	U2 Reactor Cavity Lift System	1,157,893		81,086
21	RPAC Building Renovation	1,251,749		2,213,530
22	EPU/LCM Mods	3,212,485		169,598,822
23	U2 MSR FW Heater Digital Cnt	3,595,382		12,671,121
24	U2 Control Room Chiller Rplmnt	4,004,070		59,935
25	U1 CTS Ht Exchanger - West	7,599,902		4,061,846
26	U2 CTS Heat Exchanger - West	2,132,267		6,095,719
27	316(b) Compliance (Tunnel)	8,188,272		98,247,732
28	Fukushima capital expenditures	3,245,948		56,000,693
29	U2 LP and HP Turbine	120,454,000		119,289,567
30	U2 RCP Seal Replacement (SHIEL	1,466,405		
31	Tool Crib Expansion	2,966,957		
32	Radio Communication Upgrades	1,957,789		
33	Dry Cask Load Campaign #2	1,016,855		4,957,942
34	Program Support & NRC Insp	1,386,774		2,182,519
35	**TOTAL**	**427,164,224**	**238,914,562**	**975,330,656**

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, 2013

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	U2 Reactor Cntls & Inst Upgrd	2,165,175		7,569,865
2	Wireless Network Upgrade	1,882,518		30,101
3	U1 Traveling Water Screen Rplc	1,015,374		975,553
4	RK U1 FGD Assoc	1,921,823		134,526
5	RK U1 DFGD w/ FF	20,939,713		1,465,742
6	RK 1&2 DSI FGD	25,625,652		62,978,149
7	RKP05CIIM Horiz RH ReplaceU1	2,951,764		8,826,667
8	T/I&M/Purchase/Rebuild Maj Eqp	3,568,977		
9	D/I&M/Purchase/Rebuild Maj Eqp	1,348,677		
10	T/IM/Station Asset Repl/Refurb	1,741,269		
11	T/IM/Trans Line Repl/Refurb	2,381,042		
12	TBH SPILLWAY GATE REPLACEMENT	1,132,526		
13	D/MI/Bridgman: Remote end work	1,899,860		1,785,704
14	T/I&M/IN/Trans Station Work	2,222,581		480,964
15	TL/I&M/IN/Rockport-Sullivan Tr	5,334,394		2,353,315
16	T/I&M/Transmission work	2,236,739		
17	WS-CI-IMPCo-G PPB	4,363,233		
18	RP-CI-IMPCo-G NMIB	8,046,051		
19	ET-CI-IMPCo-T ASSET IMP	9,052,374		
20	Ed-Ci-Impco-D Ast Imp	4,951,472		
21	ET-CI-I&M-T Drvn D Asset Imp	1,636,713		
22	I&M-D Service Restoration Blkt	1,393,400		
23	Other Minor Projects Under $1,000,000	37,552,622		300,357,598
24				
25				
26				
27				
28				
29				
30				
31	Completed Construction Not Classified		238,914,562	
32				
33				
34				
35	**TOTAL**	**427,164,224**	**238,914,562**	**975,330,656**

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, 2013

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	5,277,971
2		
3	Nuclear Construction Overheads	16,052,847
4		
5	Transmission Construction Overheads	4,695,267
6		
7	Distribution Construction Overheads	19,865,466
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39	**TOTAL**	**45,891,551**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Co.	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2013

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 of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2013

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT *(Account 108 & 110)*

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 202-204A, column (d), excluding retirements of non-depreciable property.
3. Accounts 108 and 110 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 cost 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	3,361,887,401	3,361,883,239	4,162	
2	Depreciation Prov. for Year, Charged to				
3	(403) Depreciation Expense	146,155,652	146,155,576	76	
4	(403.1) Decommissioning Expense	9,600,523	9,600,523	0	
5	(413) Exp. Of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify):	2,385,447	2,385,447	0	
9					
10	TOTAL Deprec. Prov. For Year *(Enter Total of Lines 3 thru 9)*	**158,141,622**	158,141,546	76	
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	72,677,707	72,033,807	643,900	
13	Cost of Removal	97,702,415	97,702,415	0	
14	Salvage (Credit)	78,071,063	78,071,063	0	
15	TOTAL Net Chrgs. For Plant Ret. *(Enter Total of lines 12 thru 14)*	**92,309,059**	91,665,159	643,900	
16	Net Earnings of Decommissioning Funds				
17	Other Debit or Credit Items (Described)				
18	Retirement WIP	0	0		
19	Asbestos ARO	2,193,414	2,193,414		
20	Transfer between Accounts 108 & 111	(4,154,789)	(4,154,789)	0	
21	Balance End of Year *(Enter total of lines 1, 10, 15, 16 & 17)*	**3,425,758,589**	3,426,398,251	(639,662)	

Section B. Balances at End of Year According to Functional Classifications

22	Steam Production	881,994,020	882,637,920	(643,900)	
23	Nuclear Production	1,437,381,763	1,437,381,763		
24	Hydraulic Production-Conventional	27,102,122	27,102,122		
25	Hydraulic Production-Pumped Storage	0	0		
26	Other Production	0	0		
27	Transmission	551,316,240	551,312,002	4,238	
28	Distribution	499,120,014	499,120,014		
29	General	28,844,430	28,844,430		
30	TOTAL (Enter total of lines 20 thru 28)	**3,425,758,589**	3,426,398,251	(639,662)	

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, 2013

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)
219	8	C	Abestos depreciation and accretion expense in account 1080013 - $876,291 Amortize Indiana jurisdictional portion of reg asset for ash ponds ARO's - ($6,677) IN deferred depreciation expense related to Cook Plant Life Cycle Management projects $1,486,291 MI deferred depreciation expense related to Cook Plant Life Cycle Management projects $29,542 Total $2,385,447

This Page Intentionally
Left Blank

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, 2013

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	27,343,689	2,390,481	29,734,170
2	Office Building Leasehold Improvements, One Summit Square, Fort Wayne, IN	2,695,099	0	2,695,099
3	Land, purchased in connection with Jefferson West 765kv Corridor, Jefferson County, IN	164,576	0	164,576
4	Land, Prosperity East 138kv Corridor, Madison County, IN	102,956	0	102,956
5	Land near Tanners Creek Plant, Lawrenceburg, IN	146,364	0	146,364
6	Land for Butler Center Substation	110,789	0	110,789
7	Land for Fuson Substation, Delaware County, IN	102,430	0	102,430
8	Minor items previously devoted to public service	8,174	0	8,174
9	Minor items - other nonutility property	460,572	50,145	510,717
	TOTAL	31,134,649	2,440,626	33,575,275

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	16,051,403
2	Accruals for Year, Charged to	
3	(417) Income from Nonutility Operations	1,016,221
4	(418) Nonoperating Rental Income	44,884
5	Other Accounts (Specify):	
6	Accounts 227 and 243	1,317,360
7	TOTAL Accruals for Year (Enter Total of lines 3 thru 6)	2,378,465
8	Net Charges for Plant Retired:	
9	Book Cost of Plant Retired	(708,146)
10	Cost of Removal	0
11	Salvage (Credit)	0
12	TOTAL Net Charges (Enter Total of lines 9 thru 11)	(708,146)
13	Other Debit or Credit Items (Describe):	
14	Reclassifications from/to Other Accounts	0
15	Balance, End of Year (Enter Total of lines 1, 7, 12, and 14)	17,721,722

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, 2013

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 Cost	Book Value	Purchases or from Improvement Disposed of (c)
1	Account 123 - Investment in Associated Companies		(see pp. 224-225)	
2				
3	Account 124 - Other Investments			
4	Franklin Real Estate and Indiana Franklin - Land Purchase Contracts			
5	- Michigan		266,733	0
6	- Other States		10,289,872	0
7				
8				
9				
10	Fiber Optic Agreements with AEP Communications, Kentucky Data		4,821,243	0
11	Link, Inc, and Citynet Fiber Network, Inc			
12				
13	Speculative Allowance Inventory			
14	- NOx		17	0
15	- SO2		0	0
16	- CO2		0	0
17				
18	Shell Building Loan		15,000	0
19				
20	Other Miscellaneous Investments		8,039	0
21				
22	Depreciation Reserve		0	0
23				
24	Ripley Land Purchase		745,386	
25				
26	Total Account 124		16,146,290	0
27				
28	Account 136 - Temporary Cash Investments			
29				
30				
31	Grand Total		16,146,290	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)	December 31, 2013

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	Book Value	Revenues for Year (g)	Gain or Loss from Improvement Disposed of (h)	Line No.
						1
						2
						3
						4
0			266,733			5
496,165			9,793,707		3,729,550	6
						7
						8
						9
170,564			4,650,679			10
						11
						12
						13
0			17			14
0			0			15
0			0			16
						17
0			15,000			18
						19
0			8,039			20
						21
0			0			22
						23
0			745,386			24
						25
666,729			15,479,561			26
						27
						28
						29
						30
666,729	0	0	15,479,561	0	3,729,550	31

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 2013/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			-104,879
5	Investment in Subsidiary AOCI			-1,521,319
6	Subtotal			23,697,802
7				
8	Price River Coal Company, Inc.	12-01-65		
9	Common Stock			27,275
10	Subtotal			27,275
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	23,725,077

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 2013/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		25,324,000		2
				3
8,843		-96,036		4
		1,249,139		5
8,843		26,477,103		6
				7
				8
		27,275		9
		27,275		10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
8,843		26,504,378		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)	December 31, 2013

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)	61,689,515	63,014,473
3	Other Accounts Receivable (Account 143 & 171 & 172) (Disclose any capital stock subscriptions received)	16,069,074	5,146,901
4	TOTAL	**77,758,589**	**68,161,374**
5	Less: Accumulated Provision for Uncollectible Accounts-Cr. (Account 144)	229,449	265,677
6	TOTAL, Less Accumulated Provision for Uncollectible Accounts	**77,529,140**	**67,895,697**
7			
8	Account 143 includes employee receivables of $712,666 @		
9	12/31/12 and $658,386 @ 12/31/13 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		229,449		0	229,449
2	Prov. For uncollectibles for current year		(40,624)		0	(40,624)
3	Account written off (less)		5,156		0	5,156
4	Charged to other accounts				82,008	82,008
5	Adjustments (explain):					0
	Adjustment to Beginning Balance		0		0	0
6	Balance end of year	0	183,669	0	82,008	**265,677**
7						
8						
9						
10						
11						

This Page Intentionally
Left Blank

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, 2013

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 any time during the year.
6. Give particulars of any notes pladged 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		Balance End of Year (e)	Interest for Year (f)
			Debits (c)	Credits (d)		
1	Account 145					
2	AEP Utility Funding LLC	103,619,364	936,046,301	997,262,757	42,402,908	879,015
3						
4	Account 146					
5						
6	AEP Generating Company	31,717,707	354,898,863	363,949,563	22,667,007	
7	AEP Memco	2,155,242	8,187,427	7,161,983	3,180,686	
8	AEP Pro Serv	0	12,739	12,130	609	
9	AEP Service Corporation	15,487,192	1,157,325,775	1,156,880,114	15,932,853	
10	AEP System Pool (AEPSC)	11,735,462	638,439,703	631,850,009	18,325,156	
11	AEP T&D Services, LLC	0	37,399	37,399	0	
12	AEP Texas Central	7,466	1,390,464	1,389,726	8,204	
13	AEP Texas North	12,592	41,569	48,488	5,673	
14	AEP Utilities, Inc.	649,870	199,704,489	199,897,917	456,442	
15	AEP Utility Funding LLC	39	15	53	1	
16	American Electric Power Co	10,335	299,802,148	299,812,466	17	
17	Appalachian Power Co	2,476,739	38,427,382	36,831,297	4,072,824	
18	Blackhawk Coal Company	3,763	78,806	80,214	2,355	
19	Cardinal Operating	364,631	12,448,557	11,163,475	1,649,713	
20	Cook Coal Terminal	24,491	225,378	249,838	31	
21	CSW Energy, Inc.	176	306	412	70	

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, 2013

RECEIVABLES FROM ASSOCIATED COMPANIES (Accounts 145, 146)

Line No.	Particulars (a)	Balance Beginning of Year (b)	Totals for Year		Balance End of Year (e)	Interest for Year (f)
			Debits (c)	Credits (d)		
1	Kentucky Power Co	9,014	724,943	724,177	9,780	
2	Kingsport Power Co	558	85,151	85,328	381	
3	Ohio Power Co	6,215,698	56,507,737	56,725,571	5,997,864	
4	Public Service Co of OK	40,104	4,208,312	4,160,898	87,518	
5	SW Electric Power Co	165,189	1,991,258	2,047,145	109,302	
6	Wheeling Power Co	448	30,772	30,895	325	
7	United Sciences	5	3,797	3,802	0	
8	AEP Holdings	(10,000)	10,000		0	
9	AEP Energy Services	370	295	642	23	
10	AEP Wind Holding Co	128	82	203	7	
11	Various Transmission	6,353,428	140,469,273	144,221,150	2,601,551	
12	AEP Transmission	50	5,881	5,216	715	
13	AEP Resources Inc.	9	0	9	0	
14	AEP C&I Company LLC	179	209	349	39	
15	AEP Investments	14	12	24	2	
16	AEP Elmwood	0	30,820	30,820	0	
17	AEP Energy, Inc.	0	13,819	13,819	0	
18	AEP Retail Energy	0	30,192	30,192	0	
19	Public Liability Co	0	45,387	45,387	0	
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	181,040,263	3,851,225,261	3,914,753,468	117,512,056	879,015

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 2013/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)	50,571,903	50,229,820	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	2,834,549	3,576,877	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	71,119,095	70,638,497	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	78,369,002	82,922,667	Electric
8	Transmission Plant (Estimated)	1,954,137	1,405,516	Electric
9	Distribution Plant (Estimated)			Electric
10	Regional Transmission and Market Operation Plant (Estimated)	891,736	805,818	
11	Assigned to - Other (provide details in footnote)	52,111	60,747	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	152,386,081	155,833,245	Electric
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	3,162,314	3,200,704	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)	208,954,847	212,840,646	

FOOTNOTE DATA

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

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

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2013

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 0f 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)	Cost (Coal) (d)
1	**On hand beginning of year**	50,571,903	1,137,110	47,674,254
2	**Received during year**	254,503,802	5,339,078	250,675,811
3	**TOTAL**	305,075,705	6,476,188	298,350,065
4	**Used during year (specify department)**			
5	Electric Generation	257,340,221	5,510,034	253,296,641
6	Storage Pile Adjustment	(2,494,336)	(56,212)	(2,494,336)
7				
8				
9				
10				
11				
12				
13				
14				
15	**Sold or transferred**			
16	**TOTAL DISPOSED OF**	254,845,885	5,453,822	250,802,305
17	**BALANCE END OF YEAR**	**50,229,820**	1,022,366	47,547,760

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, 2013

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.
21,045	2,897,649					1
29,832	3,827,991					2
50,877	6,725,640					3
						4
31,422	4,043,580					5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
31,422	4,043,580	0	0	0	0	16
19,455	**2,682,060**	**0**	**0**	**0**	**0**	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 2013/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		2014	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	375,681.00	39,590,832	111,535.00	5,066,281
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Appalachian Power Company	58,413.00	20,538,595		
10	Ohio Power Company	1,129.00			
11					
12					
13					
14					
15	Total	59,542.00	20,538,595		
16					
17	Relinquished During Year:				
18	Charges to Account 509	111,976.00	15,015,019		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23	AEP System Pool	4,081.00	569,570		
24					
25					
26					
27					
28	Total	4,081.00	569,570		
29	Balance-End of Year	319,166.00	44,544,838	111,535.00	5,066,281
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	1,170.00		357.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	1,170.00			
40	Balance-End of Year			357.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		329		
45	Gains		329		
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 2013/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.

2015		2016		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		2,105,264.00		2,754,278.00	44,657,113	1
								2
								3
				81,376.00		81,376.00		4
								5
								6
								7
								8
						58,413.00	20,538,595	9
						1,129.00		10
								11
								12
								13
								14
						59,542.00	20,538,595	15
								16
								17
						111,976.00	15,015,019	18
								19
								20
								21
								22
						4,081.00	569,570	23
								24
								25
								26
								27
						4,081.00	569,570	28
80,899.00		80,899.00		2,186,640.00		2,779,139.00	49,611,119	29
								30
								31
								32
								33
								34
								35
357.00		357.00		56,199.00		58,440.00		36
				714.00		714.00		37
								38
				357.00		1,527.00		39
357.00		357.00		56,556.00		57,627.00		40
								41
								42
								43
					51		380	44
					51		380	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 2013/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		2014	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	23,267.00	7,370	23,740.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	1,046.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Constellation Energy Comm	500.00	21,000		
10	Merrill Lynch Commodities	509.00	19,851		
11	NRG Power Marketing LLC	2,820.00	119,940		
12	Sunbury Generation LP	600.00	25,200		
13	Accrued Purchase Reversal	-2,388.00	-101,946		
14	Other	500.00	11,500		
15	Total	2,541.00	95,545		
16					
17	Relinquished During Year:				
18	Charges to Account 509	25,179.00	87,229	990.00	
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	1,675.00	15,686	22,750.00	
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				
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 2013/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.

2015		2016		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						47,007.00	7,370	1
								2
								3
						1,046.00		4
								5
								6
								7
								8
						500.00	21,000	9
						509.00	19,851	10
						2,820.00	119,940	11
						600.00	25,200	12
						-2,388.00	-101,946	13
						500.00	11,500	14
						2,541.00	95,545	15
								16
								17
						26,169.00	87,229	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
						24,425.00	15,686	29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

FOOTNOTE DATA

Schedule Page: 229 Line No.: 14 Column: b

	No.	Amount
Exelon Generation	500	11,500

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, 2013

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 Fuel Canister Reimbursement	28,278,019
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25	TOTAL	**28,278,019**

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 2013/Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	PJM #T94 Cook-Palisades 345KV	2,641	186	751	186
3	PJM #T142 E Lima-Marysville 345KV	468	186	2,432	186
4	PJM #T131 Ft Wayne-Lima 138KV	4,159	186	6,084	186
5	PJM #T130 Robison Pk-E Lima 138KV	2,540	186	4,417	186
6	PJM #S73 Lincoln-N Delphos 138KV	7,449	186	16,852	186
7	PJM #S71 Bluff Point 138KV	62	186	3,900	186
8	PJM #U4-003 Olive-Dequine 345KV	4,176	186	4,176	186
9	PJM #R03 Adams-Allen 138KV	560	186	306	186
10	PJM #T184 Olive-Dequine 345KV	1,624	186	2,003	186
11	PJM #T183 Olive-Dequine 345 KV	1,624	186	1,655	186
12	PJM #T126 Olive-Dequine 345KV	135	186	135	186
13	PJM #V4-016 Valley 138KV	6,981	186	13,249	186
14	PJM #V1-012 Haviland 138KV	17	186	3,106	186
15	PJM #W3-024 Columbia 138KV	28	186	32	186
16	PJM #Y2-010 Olive-Meadow LK 345KV	11,187	186	11,883	186
17	PJM #X2-052 Dumont-Olive 345 KV	8,959	186	25,812	186
18	PJM #Y2-107 Rob Park-Argenta 345KV	12,325	186	12,324	186
19	PJM #Y2-084 Dequine 345 KV	17,676	186	17,676	186
20	PJM #Y2-112 Keystone 345 KV	2,605	186	2,991	186
21	**Generation Studies**				
22	Cook Unit 2 Feasibility Study	20,200	107		
23	Rockport Unit 1 Feasibility Study	13,600	500		
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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 #Y2-095 Breed 745KV	9,199	186	9,199	186
3	PJM #Y2-116 Breed 745KV	4,045	186	4,045	186
4	PJM #Y1-002 NIPS-PJM 575MW	859	186	859	186
5	PJM #Y1-090 AMIL-PJM 105MW	472	186	472	186
6	PJM #Y1-091 AMIL-PJM 57MW	149	186	149	186
7	PJM #Y3-023 Countryside 12KV	203	186	203	186
8	PJM #X3-028 Sullivan 765KV	14,269	186	9,017	186
9	PJM #Y2-084 Dequine 345KV	15,396	186	11,186	186
10	PJM #Y2-010 Olive Meadow Lk 345K	17,298	186	16,663	186
11	PJM #Y3-038 Rockport 765KV	2,904	186	1,744	186
12	PJM #Z1-006 MI City-Laporte 138KV	757	186	757	186
13	PJM #Z1-051 DC Cook Unit 2 765KV	15,250	186	113	186
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter /Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	SFAS 112 Post Employment Benefits	8,896,951	3,115,796	228	2,916,868	9,095,879
2						
3	Cook Plant Refueling Levelization	26,651,661	82,433,510	various	51,105,931	57,979,240
4						
5	Unamortized Loss on Reacquired Debt	2,069,533		428	206,953	1,862,580
6	Amort 1/1995 - 12/2022					
7						
8	Unrealized Loss on Forward Commitments	1,198,465	44,410,639	various	45,609,104	
9						
10	Deregulation - Customer Educ & Transition Filing	1,492,625	209,022	various	1,701,647	
11						
12	Asset Retirement Obligations	807,935		407,920	111,813	696,122
13	Amortz 3/2009 - 3/2020					
14	Per IURC Cause Order #43306					
15						
16	Indiana Rate Case expenses		932,217	928	258,949	673,268
17	Amortz 3/2013 - 2/2016					
18	Per IURC Cause Order #44075					
19						
20	Michigan Rate Case expenses	115,058		928	92,046	23,012
21	Amort 04/2012 - 03/2014					
22	Per MPSC Case U-16801					
23						
24	Deferred RTO Equity Carrying Charges	(420,239)	88,116	407	13	-332,136
25	Amort 1/2005 - 12/2019					
26						
27	BridgeCo Transmission Org Funding	895,255		407	143,083	752,172
28	Amort 1/2005 - 12/2019					
29	FERC Docket No. AC04-101-000					
30						
31	PJM Integration Payments	899,471		407	434,448	465,023
32	Amort 1/2005 - 12/2014					
33	FERC Docket No. EL05-74-000					
34						
35	Other PJM Integration	833,252		407	133,173	700,079
36	Amort 1/2005 - 12/2019					
37	FERC Docket No. AC04-101-000					
38						
39	Carrying Charges - RTO Startup Costs	506,997	129,380	407	109,065	527,312
40	Amort 1/2005 - 12/2019					
41	FERC Docket No. AC04-101-000					
42	& FERC Docket No. EL05-74-000					
43						

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 2013/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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter /Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Alliance RTO Deferred Expense	514,133		407	82,171	431,962
2	Amort 1/2005 - 12/2019					
3	FERC Docket No. AC04-101-000					
4						
5	Unrecovered Fuel Cost	4,809,846	17,582,079	various	18,995,031	3,396,894
6						
7	SFAS 158 Employer Accounting for Defined	220,797,410	135,843,326	various	256,508,528	100,132,208
8	Benefit Pension & Other Postretirement Plans					
9						
10	DSM Energy Optimization Program - Michigan	2,608,220	2,310,529	908,421	462,229	4,456,520
11	Under-recovered costs					
12						
13	Indiana Clean Coal Technology Rider	56,881	58,311	various	95,283	19,909
14	Carrying Charges					
15	Per IURC Cause Order #43636					
16						
17	Deferred Nuclear Decommisioning Study Costs	3,667		524	3,667	
18	Amort 12/2010 - 11/2013					
19	Per MPSC Case U-16180					
20						
21	Enhanced post-9/11 Cook Plant Security Costs	366,600		524	132,360	234,240
22	Amort 12/2010 - 11/2015					
23	Per MPSC Case U-16180					
24						
25	Deferred Severance Costs	3,687,833	15,717	various	1,280,117	2,423,433
26	Amort 12/2010 - 11/2015					
27	Per MPSC Case U-16180					
28						
29	SFAS 109 Deferred FIT	138,419,942	63,293,867	various	62,627,562	139,086,247
30						
31	SFAS 109 Deferred SIT	114,728,233	25,807,711	283	1,879,380	138,656,564
32						
33	Carbon Capture & Storage Project FEED	143,865		506	115,092	28,773
34	Study Costs - MI Portion					
35	Amortization 4/12 - 3/14					
36	Per MPSC Case U-16801					
37						
38	Carbon Capture & Storage Project FEED	1,380,156		506	1,380,156	
39	Study Costs					
40						
41	Under Recovery of PJM Expenses	13,998,483	953,443	various	14,951,926	
42						
43						

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 2013/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		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter /Year Account Charged (d)	Written off During the Period Amount (e)	
1	City of Fort Wayne Right to Serve Settlement	4,300,000		588	294,521	4,005,479
2	Amortization 3/13 - 4/25					
3	Per IURC Cause Order #44075					
4						
5	City of Fort Wayne Settlement - Carry Charge	898,377	46,201	588	63,529	881,049
6	Amortization 3/13 - 4/25					
7	Per IURC Cause Order #44075					
8						
9	City of Ft. Wayne Betterments/Generation Settlement	5,900,000		588	404,110	5,495,890
10	Amortization 3/13 - 4/25					
11	Per IURC Cause Order #44075					
12						
13	Cook Turbine Replacement Deferred Depreciation - Mi	335,466	447,598			783,064
14	Per MPSC Case U-16801					
15						
16	Cook Turbine Replacement CC - Michigan	450,815	807,617	421	453,068	805,364
17	Per MPSC Case U-16801					
18						
19	Cook Turbine Replacement CC _Indiana		2,873,638	421	1,010,086	1,863,552
20	Per IURC Cause Order #44075					
21						
22	Cook Unit 2 Baffle Bolts		7,498,405	530	249,947	7,248,458
23	Amort 3/2013 - 2/2038					
24	Per IURC Cause Order #44075					
25						
26	Capacity Settlement - IN Portion		21,945,013			21,945,013
27	Per IURC Cause Order #44075					
28						
29	Michigan Renewable Energy Surcharge		930,271	various	408,478	521,793
30						
31	Deferred Depreciation - Cook Life Cycle Management		29,664	403	122	29,542
32	Michigan Portion					
33	Per MPSC Case U-17026					
34						
35	SFAS Medicare Subsidy		12,241,617	various	1,020,135	11,221,482
36						
37	Cook Life Cycle Management Carry Charge - MI		215,951	421	82,043	133,908
38	Per MPSC Case U-17026					
39						
40	Major Storm Damage Restoration Reserve		4,081,089	593	2,244,959	1,836,130
41	Per IURC Cause Order #44075					
42						
43	Deferred Depreciation - Cook Life Cycle Management		1,504,962	403	18,671	1,486,291

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 2013/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		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter /Year Account Charged (d)	Written off During the Period Amount (e)	
1	Indiana Portion					
2	Per IURC Cause Order #44182					
3						
4	Cook Life Cycle Management Carry Charge - IN		3,873,400	421	1,500,415	2,372,985
5	Per IURC Cause Order #44182					
6						
7	Deferred Prop Tax - Cook Life Cycle Management - IN		233,547			233,547
8	Per IURC Cause Order #44182					
9						
10	Deferred Environmental Compliance Costs		858,131	509	294,829	563,302
11						
12	River Transportation Selling Price Variance	4,576,027	11,570,205	254	12,056,451	4,089,781
13						
14	OSS Margin Sharing		4,412,435	447	3,880	4,408,555
15						
16	Tanners Creek Abandon Plant Stranded Costs		3,896,482			3,896,482
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	**TOTAL :**	561,922,918	454,649,889		481,441,839	535,130,968

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 2013/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	35,563,045	52,800,026	408	51,629,383	36,733,688
2						
3	Property Taxes - Capital Leases	89,811	326,242	408	315,981	100,072
4						
5	Labor Accruals	11,665	838,806	various	794,471	56,000
6						
7	Agency Fees, Factored Accts Rec	2,468,939	29,902,923	various	29,586,729	2,785,133
8						
9	River Transport Division	176,659	166,913,560	various	166,460,262	629,957
10						
11	Deferred Rate Case expense	447,612	3,407	various	446,981	4,038
12						
13	Unamortized Credit Line Fees	1,094,166	615,787	431	482,372	1,227,581
14	Amortized thru July 2017					
15						
16	Allowances	3,043	195,597	158,509	197,797	843
17						
18	Defd Non-taxable Leased Assets	647,582	685,849	146	969,313	364,118
19						
20	Estimated Barging Bills	-509,368	113,680,495	various	113,171,127	
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress	454,472				473,186
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	40,447,626				42,374,616

This Page Intentionally Left Blank

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, 2013

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	417,309,650	3,088,724	25,093,508
3	Reg Liability - SFAS 143 - ARO	152,500,860	15,681,489	72,170,110
4	Capitalized Cook Costs	20,468,534	6,296,815	0
5	Capitalized Interest Expense	27,521,655	1,587,169	5,111,981
6	SFAS 158	77,279,094	42,724,398	491,577
7	Other (see pp. 234.1A-234.1B)	60,687,899	89,432,903	57,168,986
8	TOTAL (Account 190) (Enter total of lines 2 thru 7)	755,767,692	158,811,498	160,036,162
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)	76,318,771	0	
18	TOTAL (Account 190) *(Enter total of lines 8, 16 & 17)*	832,086,463	**158,811,498**	**160,036,162**
19	Classification of Total:			
20	Federal Income Tax	832,837,654	158,811,498	160,036,162
21	State Income Tax	(751,191)		
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	5,616,483	7,112,564
Non-Utility 190.2 State	-751,191	-374,202
SFAS 133	11,284,415	8,927,948
SFAS 87	3,913,442	444,805
SFAS 109	56,255,622	69,930,243
Total	76,318,771	86,041,358

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, 2013	

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
						439,314,434	2
						208,989,481	3
						14,171,719	4
						31,046,467	5
						35,046,273	6
		236.00	11,730,296	236.00	9,275,303	30,878,975	7
0	0		11,730,296		9,275,303	759,447,349	8
							9
							10
							11
							12
							13
							14
						0	15
0	0		0		0	0	16
5,632,923	7,505,993	Various	25,245,532	Various	17,396,015	86,041,358	17
5,632,923	7,505,993		36,975,828		26,671,318	845,488,707	18
							19
5,192,308	6,688,389		36,975,828		26,671,318	845,862,909	20
440,615	817,604					(374,202)	21
							22

NOTES *(Continued)*

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, 2013

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)	Amounts Credited to Account 411.1 (d)
1				
2	Contributions and Advances for Construction	6,875,078	1,118,653	395,079
3	Provisions for Loss Trading Credit Risk	439,681	337,308	30,114
4	Property Tax Deferrals	(2,403,566)	6,216,952	7,719,531
5				
6	Pre 04/83 Nuclear Fuel Cost	14,845,577	299,034	417,509
7	Nuclear Decommissioning	(462,147)	4,899	1,432
8	IRS Settlements	(4,215,175)	2,024,140	84,064
9	Deferred Gain Sale of Rockport Unit 2	12,518,151	1,297,351	37,068
10	Amortization of Step Up ITC Rockport Unit 2	3,976,281	397,583	0
11	Accrued Vacation Pay	4,751,296	1,130,639	1,141,715
12	Accrued Severance Benefits	475,066	467,435	
13	Accrued Incentive Plans	9,740,088	8,059,237	11,876,155
14	Book Provision for Uncollectible Debt	80,308	536,767	549,447
15	Mark to Market Gain/Loss	5,636,792	8,158,348	4,188,957
16	Capitalized Software Tax	24,659	22,266	59,212
17	Revenue Refunds	2,358,750	2,138,117	764,830
18	SFAS 112 Post Employment Benefits	2,029,047	651,822	326,357
19				
19	Accrued Income Tax and Interest	252,200	392,950	401,339
20	Accrued Pension Expense	(43,002,659)	471	6,215,886
21	SFAS 106 Post Retirement Benefits	8,573,157	10,247,607	237,241
22	Accrued SIT	(201,015)		
23	Provision for Litigation	(8,680,000)		
24	NOL-Deferred Tax Asset	29,984,391	34,401,515	16,180,981
25	Other Miscellaneous	17,091,939	11,529,809	6,542,069
26	Total Other	60,687,899	89,432,903	57,168,986
27				
28				
29				
30				

NOTES

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, 2013

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
						6,151,504	2
						132,487	3
						(900,987)	4
						0	5
						14,964,052	6
						(465,614)	7
						(6,155,251)	8
						11,257,868	9
						3,578,698	10
						4,762,372	11
						7,631	12
						13,557,006	13
						92,988	14
						1,667,401	15
						61,605	16
						985,463	17
						1,703,582	18
						0	18
						260,589	19
						(36,787,244)	20
						(1,437,209)	21
						(201,015)	22
						(8,680,000)	23
						11,763,857	24
		236.00	11,730,296	236.00	9,275,303	14,559,192	25
			11,730,296		9,275,303	30,878,975	26
							27
							28
							29
							30

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, 2013

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	8-3/4% Series First Mortgage Bonds due 2/2017	3/1994	100,000,000	(7,562,180)
8	This debt was replaced by the following issuances:			
9	6.55% FMB due 3/2004 (Replaced by 6.875% SUN)			
10	7.50% FMB due 3/2024 (Redeemed 4/2004, no replacement			
11	debt was issued.)			
12	No Replacement Debt Issued - Amort thru 2/1/2017			
13				
14	7.0% Pollution Control Revenue Bonds	11/2003	25,000,000	(600,619)
15	Lawrenceburg, IN Series Due 4/2015			
16	Replaced by 2.625% Lawrenceburg Bonds Due 10/2019			
17	Loss being amortized over life of replacement debt			
18				
19	5.9% Pollution Control Revenue Bonds, due 11/2021	11/2004	52,000,000	(1,089,232)
20	City of Lawrenceberg, Indiana. (Replaced by VAR%			
21	Lawrenceberg, IN Bonds due 11/2021.)			
22				
23				
24	9-1/4% Pollution Control Revenue Bonds, due 8/2014	8/1995	50,000,000	(3,928,658)
25	City of Rockport, Indiana.			
26	Replaced by 6.55% Rockport Bonds due 6/2025			
27	Replaced 5/06 by VAR% Rockport Bonds Due 6/2025,			
28	with $500,000 premium paid for early redemption			
29				
30	VAR% Pollution Control Revenue Bonds, due 8/2014	8/1995	50,000,000	(785,290)
31	City of Rockport, Indiana.			
32	Replaced by VAR% Rockport Bonds due 6/2025			
33				
34	9.00% Pref Stock Subject to Mandatory Redemption	4/1993	40,000,000	(896,000)
35	8.60% Pref Stock Subject to Mandatory Redemption	12/1993	40,000,000	(864,000)
36	8.68% Pref Stock Subject to Mandatory Redemption	1/1994	30,000,000	(540,000)
37	7.76% Pref Stock Subject to Mandatory Redemption	3/1994	35,000,000	(798,000)
38	6.875% Pref Stock Subject to Mandatory Redemption	1/2005	15,750,000	
39	5.90% Pref Stock Subject to Mandatory Redemption	1/2005	13,200,000	(861,392)
40	6.25% Pref Stock Subject to Mandatory Redemption	1/2005	19,250,000	
41	6.30% Pref Stock Subject to Mandatory Redemption	1/2005	13,245,000	
42	(Balance transferred from FERC Acct 210 to 189)			
43				
44	7.6% Pollution Control Revenue Bonds	11/2003	40,000,000	(338,620)
45	Rockport, IN Series Due 03/2016			
46	Replaced by 2.625% Rockport IN Bonds Due 04/2025			
47	Loss being amortized over life of replacement debt			

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, 2013

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.
934,371		84,304	850,067	1
				2
				3
1,319,270		118,143	1,201,127	4
				5
				6
134,744		32,998	101,746	7
				8
				9
				10
				11
				12
				13
390,298		57,822	332,476	14
				15
				16
				17
				18
753,347		85,284	668,063	19
				20
				21
				22
				23
1,749,791		140,923	1,608,868	24
				25
				26
				27
				28
				29
325,928		26,249	299,679	30
				31
				32
				33
340,391		-	340,391	34
				35
				36
				37
				38
				39
				40
				41
				42
				43
689,056		56,250	632,806	44
				45
				46
				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)	December 31, 2013

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	VAR % Pollution Control Revenue Bonds, due 10/2019	5/2008	25,000,000	(323,600)
2	Series F Lawrenceburg			
3	Remarketed as Series I VAR%			(134,515)
4				
5				
6	VAR % Pollution Control Revenue Bonds, due 11/2021	5/2008	52,000,000	(1,013,352)
7	Series G Lawrenceburg			
8	Remarketed as Series H VAR%			(261,800)
9				
10	Early Redemption of $150M Series D Senior Unsecured Note	10/2010	150,000,000	(6,651,901)
11	Orginal Maturity Date of December 31, 2032			
12	Redeemed October 15, 2010			
13				
14	Redemption premium of $175M Senior Unsecured Note	12/2013	175,000,000	(7,399,750)
15	Original Maturity Date of November 16, 2014			
16	Redeemed December 20, 2013			
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
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				
46				
47				
48				
49				
50				

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, 2013

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.
192,731		28,553	164,178	1
				2
107,090		15,672	91,418	3
				4
				5
667,175		75,530	591,645	6
				7
218,510		24,737	193,773	8
				9
5,979,236		298,961	5,680,275	10
				11
				12
				13
	7,399,750	511,043	6,888,707	14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
13,801,938	**7,399,750**	**1,556,469**	**19,645,219**	36
				37
(18,403)	1,712	-	(16,691)	38
				39
				40
				41
(18,403)	**1,712**	**-**	**(16,691)**	42
				43
13,783,535	**7,401,462**	**1,556,469**	**19,628,528**	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 2013/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			
5	Par Value $100	2,250,000		
6	Par Value $25	11,200,000		
7				
8				
9	TOTAL Preferred Stock	13,450,000		
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

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
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42

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 31,2013

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 205 - *Preferred Stock Subscribed*		
5	None		
6			
7	Account 203 - *Common Stock Liability for Conversion*		
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 2013/Q4

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

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

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

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

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2013

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 2013

Series	Due Date	Principal Amount	Date Retired
Series F - 5.05% Fixed Rate	11/15/2014	175,000,000	12/20/2013

2. Securities issued during 2013

Series	Due Date	Principal Amount	Date Issued
Series J - 3.20% Fixed Rate	3/15/2023	250,000,000	3/18/2013

3. Securities Remarketed during 2013

Series	Due Date	Principal Amount	Date Remarketed
Series D - 5.25% Fixed Rate	4/1/2025	40,000,000	4/4/2013

This Page Intentionally
Left Blank

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 2013/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	Account 224 - Other Long Term Debt		
8	Spent Nuclear Fuel Disposal Costs Prior		
9	To April 7, 1983 - Basic Fee Assessment & Interest		
10			
11	Pollution Control Revenue Bonds		
12	Lawrenceburg, IN		
13	Series I - Weekly Auction Rate	25,000,000	178,919
14			103,287
15			
16	Series H - Weekly Auction Rate	52,000,000	331,889
17			172,181
18	Rockport, IN		
19	Series D - 5.25% Fixed Rate	40,000,000	1,157,720
20			
21	Series 2002 A - 4.625% Fixed Rate	50,000,000	296,785
22			325,000 D
23			382,272
24			136,351 D
25			444,593
26			74,250
27			74,250
28			74,250
29			74,250
30			74,250
31			74,250
32			
33	TOTAL	1,828,802,388	24,734,004

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.
						1
04/04/2013	04/01/2025			-40,000,000		2
				-40,000,000		3
						4
						5
						6
						7
						8
				265,390,551		9
						10
						11
						12
5/22/2008	10/1/2019	5/22/2008	10/1/2019	25,000,000	19,637	13
3/24/2011	10/1/2019	3/24/2011	3/24/2013			14
						15
5/20/2008	11/1/2021	5/20/2008	11/1/2021	52,000,000	48,851	16
3/16/2011	11/1/2021	3/16/2011	3/16/2013			17
						18
4/25/2008	4/1/2025	4/25/2008	4/1/2025	40,000,000	542,500	19
						20
8/1/1985	6/1/2025	8/1/1985	6/1/2025	50,000,000	2,312,500	21
						22
6/1/2002	6/1/2007	6/1/2002	6/1/2007			23
						24
6/1/2007	6/1/2025	6/1/2007	6/1/2025			25
		6/1/2008	5/31/2009			26
		6/1/2009	5/31/2010			27
		6/1/2010	5/31/2011			28
		6/1/2011	5/31/2012			29
		6/1/2012	5/31/2013			30
		6/1/2013	5/31/2014			31
						32
				1,865,671,693	92,594,357	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

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

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Series 2009 A - 6.25% Fixed Rate	50,000,000	353,976
2	per IURC Order #43445, approved 4/9/08		
3	Bonds subj to mand tender for purchase (puttable) on 6/2/14		
4			
5	Series 2009 B - 6.25% Fixed Rate	50,000,000	353,976
6	per IURC Order #43445, approved 4/9/08		
7	Bonds subj to mand tender for purchase (puttable) on 6/2/14		
8	Brokerage Fees on Auction Rate Notes		
9			
10	Senior Unsecured Notes		
11			
12	Series F - 5.05% Fixed Rate	175,000,000	1,302,944
13			637,000 D
14			
15	Amortization of Cash Flow Hedge on 5.05% SUN		
16			
17	Series G - 5.65% Fixed Rate	125,000,000	906,746
18			176,250 D
19			
20	Amortization of Cash Flow Hedge on 5.65% SUN		
21			
22	Series H - 6.05% Fixed Rate	400,000,000	3,815,383
23			2,272,000 D
24			
25	Amortization of Cash Flow Hedges on 6.05% SUN		
26			
27	Series I - 7.00% Fixed Rate	475,000,000	3,333,197
28			3,201,500 D
29			
30	Series J - 3.20% Fixed Rate	250,000,000	2,027,500
31			1,625,000 D
32	Amortization of Interest Rate Swap on 3.20% SUN		
33	TOTAL	1,828,802,388	24,734,004

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 2013/Q4

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
3/26/2009	6/1/2025	4/1/2009	5/31/2014	50,000,000	3,125,000	1
						2
						3
						4
3/26/2009	6/1/2025	4/1/2009	5/31/2014	50,000,000	3,125,000	5
						6
						7
						8
						9
						10
						11
11/16/2004	11/15/2014	11/16/2004	11/15/2014		8,567,465	12
						13
						14
		11/16/2004	11/15/2014		877,840	15
						16
12/7/2005	12/1/2015	12/1/2005	11/30/2015	125,000,000	7,062,500	17
						18
						19
		12/1/2005	11/30/2015		-383,570	20
						21
11/14/2006	3/15/2037	11/14/2006	3/15/2037	400,000,000	24,200,000	22
						23
						24
		11/14/2006	2/28/2037		421,740	25
						26
1/15/2009	3/15/2019	1/1/2009	2/28/2019	475,000,000	33,250,000	27
						28
						29
3/18/2013	3/15/2023	3/18/2013	3/15/2023	250,000,000	6,288,889	30
						31
		3/18/2013	3/15/2023		1,271,804	32
				1,865,671,693	92,594,357	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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	Fort Wayne Settlement	26,802,388	
2			
3	Multiple Draw Term Loan	110,000,000	736,535
4	Variable Rate		
5	SUBTOTAL - Acct 224 - Other Long Term Debt	1,828,802,388	24,716,504
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	1,828,802,388	24,734,004

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	19,468,642		1
						2
5/30/2012	5/30/2015	6/1/2012	5/30/2015	103,812,500	1,864,201	3
						4
				1,905,671,693	92,594,357	5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				1,865,671,693	92,594,357	33

Schedule Page: 256 Line No.: 9 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. Fuel consumed prior to April 7, 1983 has been recorded as Long-term debt

Schedule Page: 256 Line No.: 13 Column: a

The $25 million City of Lawrenceburg Series I PCRB was issued 5/22/2008 & has a maturity date of 10/1/2019. It bears a weekly floating interest rate. Issuance expenses totalling $178,919 will be amortized through the original maturity date. On March 24th, 2011, these bonds were remarketed, keeping the weekly auction rate. There were $103,287 in issuance expenses incurred in this remarketing. These expenses will be amortized for 24 months.

Schedule Page: 256 Line No.: 16 Column: a

The $52 million City of Lawrenceburg Series H PCRB was issued 5/20/2008 & has a maturity date of 11/1/2021. It bears a weekly floating interest rate. Issuance expenses totalling $331,889 will be amortized through the maturity date. On March 16, 2011, these bonds were remarketed, keeping the weekly auction rate. There were $172,181 in issuance expenses incurred in this remarketing. These expenses will be amortized for 24 months.

Schedule Page: 256 Line No.: 19 Column: a

The $40 million City of Rockport Series 2003 C PCRB was re-marketed 4/25/2008 as $40 million City of Rockport Series D PCRB, at a fixed 5.25% rate. The original 4/1/2025 maturity date remained unchanged.

Schedule Page: 256 Line No.: 21 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, 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 issued in June 2008 that guarantees the principal if Indiana Michigan Power was to default on this note. This policy cost $74,250, covers the period of June 2008 - May 2009 and was amortized over that period. This policy has been renewed annually in June 2009, June 2010, June 2011, June 2012 and June 2013 each time costing $74,250 & to be fully amortized over each 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. Issuance expenses totaling $353,976 will be amortized through the 6/2/2014 put date.

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

Subject to mandatory tender for purchase (puttable) on 6/2/2014.

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. Issuance expenses totaling $353,976 will be amortized through the 6/2/2014 put date.

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

Subject to mandatory tender for purchase (puttable) on 6/2/2014.

Schedule Page: 256.1 Line No.: 12 Column: a

Early redemption prior to the 11/15/2014 maturity date - redeemed on 12/20/2013.

Schedule Page: 256.1 Line No.: 27 Column: a

The $475 million 7.00% fixed rate Series I Senior Unsecured Note was issued 1/15/2009 with a maturity date of 3/15/2019. Issuance expenses totalling $3,333,197 & discount expense of $3,201,500 will be amortized through February 2019.

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

The $250 million 3.20% fixed rate Series J Senior Unsecured Note was issued 3/18/2013 with a maturity date of 3/15/2023. Issuance expenses totaled $2,027,500 and discount expense of $402,500 will be amortized through March 2023.

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 $110 million multiple draw term loan was issued on May 30, 2012. The interest rate is variable and the maturity date is May 30, 2015. The intial draw took place on June 4, 2012 for $20 million with a subsequent draw on November 30, 2012 for $90M. Quarterly retirements totaling $6,187,500 began

This Page Intentionally
Left Blank

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, 2013

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	0	8,325,215,948	8,325,215,948	0	70,159
3	SUBTOTAL	0	8,325,215,948	8,325,215,948	0	70,159
4	Account 234					
5	AEP Transmission Companies - Various	2,622,906	50,653,849	48,650,312	619,369	
6	AEP Holding	(10,000)		10,000	0	
7	AEP Resources	0			0	
8	AEP Generating Company	26,180,271	293,261,893	291,709,145	24,627,523	
9	AEP Memco, LLC	7,945,701	72,547,518	75,991,898	11,390,081	
10	AEP Retail Energy	(0)	27,011	27,011	(0)	
11	AEP Energy Inc.	0	13,508	13,508	0	
12	AEP ProServ	0	843	843	0	
13	AEP Service Corporation	18,605,389	299,782,153	294,178,196	13,001,432	
14	AEP System Pool (AEPSC)	13,604,465	588,077,784	590,988,837	16,515,518	
15	AEP Texas Central Company	4,151	434,364	178,355	(251,858)	
16	AEP Texas North Company	3,821	45,156	44,128	2,793	
17	AEP Energy Partners	0	394	394	0	
18	AEP Coal, Inc	0	770	770	0	
19	AEP Utilities, Inc	0	2,573	2,573	0	
20	AEP Utility Funding LLC	19,470	32,400	18,957	6,027	
21	American Electric Power Co	977,895	445,171,536	444,631,723	438,082	
22	Appalachian Power Co	23,134,655	36,998,721	34,844,458	20,980,392	
23	Blackhawk Coal Company	46,178	143,221	99,790	2,747	
24	Cardinal Operating Company	9,911	134,185	124,326	52	
25	Conesville Coal Prep Co	0	637	637	0	
26	Cook Coal Terminal	6,349,354	60,291,989	59,521,118	5,578,483	
27	Electric Transmission TX	0	439	439	0	
28	Franklin Real Estate Company	0	18,499	18,499	0	
29	Indiana Franklin Realty, Inc	(0)	177,791	177,791	(0)	
30	Kentucky Power Co	78,085	542,701	479,393	14,777	
31	Kingsport Power Co	0	4,783	5,429	646	
32	Ohio Power Co	4,760,156	24,149,266	19,723,470	334,360	
33	Public Service Co of OK	23,221	999,152	1,034,267	58,336	
34	Public Liability	0	3,121	3,121	0	
35	Southwestern Electric Power Co	317,462	2,448,829	2,195,178	63,811	
36	United Sciences Testing, Inc	366	77,343	76,977	0	
37	Wheeling Power Co	0	12,650	13,977	1,327	
38					0	
39	SUBTOTAL	104,673,457	1,876,055,079	1,864,765,520	93,383,898	0
40						
41	TOTAL	104,673,457	10,201,271,027	10,189,981,468	93,383,898	70,159

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, 2013

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)	247,048,601
2	Allocations:	
3	Net Other Income and Deductions	23,604,968
4	Interest Charges	93,149,867
5	Net income for the year (page 117 line 78)	177,503,702
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	(135,151,152)

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, 2013

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.
247,048,601		1
		2
23,604,968		3
93,149,867		4
		5
		6
		7
		8
		9
		10
		11
		12
		13
		14
		15
		16
		17
		18
		19
		20
		21
		22
		23
		24
		25
(135,151,152)		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, 2013

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		177,504
Federal Income Taxes		76,462
State and Local Income Taxes		(1,357)
PreTax Book Income		252,609
Increase (Decrease) in Taxable Income resulting from:		
Allowance for Funds Used During Construction and Interest Capitalized		(15,146)
Amortization of Deferred Book Gain - Rockport Unit 1 Sale		(3,707)
Book Accruals and Deferrals		(1,487)
Book/Tax Unit Property Adj		(63,708)
Deferred Fuel Cost		3,143
Emission Allowances Net		(9,287)
Equity in Earnings Subsidiary Companies		(9)
Excess Tax vs Book Depreciation		(176,412)
Mark to Market		7,055
Nuclear Book Deferred Cost		(31,327)
Nuclear Decommissioning Costs		(224,821)
Nuclear Fuel Adjustments		(38,666)
Nuclear Fuel Disposal Costs		(865)
Pollution Control		84
Property Tax		1,659
Removal Costs		(25,592)
Relocation Costs		(2,100)
Revenue Refunds		(3,924)
SFAS 143 - ARO		229,622
Tax Accruals/Tax Deferrals		(20,336)
Other (Net)		(12,112)
Federal Tax Net Income - Estimated Current Year Taxable Income (Separate Return Basis)		(135,327)
Current State Income Taxes		(176)
Federal Taxable Income		(135,151)
Computation Tax*		
Federal Income Tax on Current Year Taxable Income (Separate Return Basis) at Statutory Rate of 35%		(47,303)
Adjustment due to System Consolidation	a	-
Estimated Taxes Currently Payable	b	(47,303)
Tax Provision Adjustment		(2,175)
NOL Reclass		(16,875)
IRS Audit Settlement		13,403
R&D Credit		43
Adjustment of Prior Years Accruals(Net)		12,431
Estimated Current Year Federal Income Taxes (Net)		(40,476)

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

(b) The Company joins in the filing of a consolidated Federal income tax return with its affiliated companies in the AEP system. The allocation of the AEP System's consolidated Federal income tax to the System companies allocates the benefit of 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 2013 System Federal income taxes will not be available until the consolidated Federal income tax return is completed and filed by September 2014. 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.

This Page Intentionally
Left Blank

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 2013/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)	Adjustments (f)
1	FEDERAL:					
2	INCOME	-8,852,962		-51,995,595	-18,587,857	-906,058
3	FICA - 2013	2,223,557		18,755,063	17,975,521	
4	UNEMPLOYMENT - 2013	8,347		238,085	124,513	
5	EXCISE TAX - 2012	374,225		10,783	385,008	
6	EXCISE TAX - 2013			1,315,651	991,429	
7	SUBTOTAL Federal	-6,246,833		-31,676,013	888,614	-906,058
8						
9	STATE OF INDIANA:					
10	INCOME 2011	-5,403,700				5,403,700
11	INCOME 2012	-1,306,050		1,546,829	240,779	
12	INCOME 2013			611,631	1,917,800	
13	UNEMPLOYMENT IN - 2013	3,954		302,367	249,470	
14	UTIL RECEIPTS TAX - 2012			-31,995	-31,995	
15	UTIL RECEIPTS TAX - 2013			16,279,000	16,279,000	
16						
17	INDIANA LICENSE TAX			22	22	
18	SALES & USE TAX - 2012	536,837		7,776	544,613	
19	SALES & USE TAX - 2013			3,541,271	2,751,680	
20						
21	PUBLI SERV COMM-2012		317,745	635,491	317,746	
22	PUBLI SERV COMM-2013			703,152	1,054,728	
23						
24	REAL & PERS PROP-2005			-6,011	-6,011	
25	REAL & PERS PROP-2010			1,976	1,976	
26	REAL & PERS PROP-2011			-202,401	-202,401	
27	REAL & PERS PROP-2012	18,847,196		295,162	19,142,358	
28	REAL & PERS PROP-2013			19,075,016	105	
29						
30	PERS PROP LEASED-2012	294,000		-40,504	253,496	
31	PERS PROP LEASED-2013			271,400		
32						
33	REAL PROP LEASED-2012	234,478		-19,941	214,537	
34	REAL PROP LEASED-2013			942,738	778,663	
35						
36	SUBTOTAL Indiana	13,206,715	317,745	43,912,979	43,506,566	5,403,700
37						
38						
39						
40						
41	TOTAL	40,058,941	1,175,988	50,194,344	80,360,752	15,807,838

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 (I) 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
(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)	No.
						1
-43,166,758		-55,069,915			3,074,320	2
3,003,099		12,737,766			6,017,297	3
121,919		253,590			-15,505	4
					10,783	5
324,222		12,446			1,303,205	6
-39,717,518		-42,066,113			10,390,100	7
						8
						9
						10
		1,430,344			116,485	11
-1,306,169		292,156			319,475	12
56,851		237,544			64,823	13
		-31,995				14
		16,279,000				15
						16
		22				17
					7,776	18
789,591					3,541,271	19
						20
		635,491				21
	351,576	703,152				22
						23
		-6,011				24
		1,976				25
		-204,676			2,275	26
		3,377,689			-3,082,527	27
19,074,911		15,587,580			3,487,436	28
						29
		8,499			-49,003	30
271,400		226,170			45,230	31
						32
					-19,941	33
164,075					942,738	34
						35
19,050,659	351,576	38,536,941			5,376,038	36
						37
						38
						39
						40
26,155,820	1,631,437	29,303,011			20,891,333	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 2013/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 Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	STATE OF KENTUCKY:					
2						
3	KY INCOME 2012	-312,042		82,882	-229,160	
4	KY INCOME 2013			-9,236	341,963	
5	Subtotal Kentucky	-312,042		73,646	112,803	
6	STATE OF MICHIGAN:					
7	MI INCOME 2012	-3,645,236		1,604,928	-2,040,308	
8	MI INCOME 2013			-35,308	2,127,008	
9	MI SBT					
10	MI CITIES	-1,279				
11	UNEMPLOYMENT - 2013	5,386		792,981	629,550	
12	PUBL SERV COMM'S-2012		118,486	384,657	266,171	
13	PUBL SERV COMM'S-2013			167,525	248,512	
14	USE TAX-2012	464,308	139,157	5,073	330,224	
15	USE TAX - 2013			1,615,988	1,829,069	
16	SALES TAX - 2012		600,600		-600,600	
17	SALES TAX - 2013				684,965	
18						
19	REAL & PERS PROP-2011	8,199,391		48,981	8,248,372	
20	REAL & PERS PROP-2012	32,250,191			22,781,474	
21	REAL & PERS PROP-2013			33,479,134		
22						
23	PERS PROP LEASED-2011	6,131		-3,511	2,620	
24	PERS PROP LEASED-2012	40,809			13,778	
25	PERS PROP LEASED-2013			54,842		
26						
27	REAL PROP LEASED-2011	28,844		3,243	32,087	
28	REAL PROP LEASED-2012			209,000	181,184	
29	SUBTOTAL Michigan	37,348,545	858,243	38,327,533	34,734,106	
30						
31	DE License Tax			1,250	1,250	
32	SUBTOTAL DELAWARE			1,250	1,250	
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	40,058,941	1,175,988	50,194,344	80,360,752	15,807,838

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 2013/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
		28,083			54,799	3
-351,199		-28,585			19,349	4
-351,199		-502			74,148	5
						6
		1,584,465			20,463	7
-2,162,316		-160,746			125,438	8
						9
-1,279						10
168,817		700,011			92,970	11
		384,657				12
	80,987	167,525				13
		12,602			-7,529	14
300,828	513,909	119,611			1,496,377	15
						16
	684,965					17
						18
		48,981				19
9,468,717		30,435,644			-30,435,644	20
33,479,134					33,479,134	21
						22
		-3,511				23
27,031		40,809			-40,809	24
54,842					54,842	25
						26
		3,243				27
27,816		209,000				28
41,363,590	1,279,861	33,542,291			4,785,242	29
						30
		1,250				31
		1,250				32
						33
						34
						35
						36
						37
						38
						39
						40
26,155,820	1,631,437	29,303,011			20,891,333	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 2013/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)	Adjustments (f)
1	STATE OF WEST VIRGINIA:					
2	LICENSE TAX			50	50	
3	WEST VA INC TAX-2009	-413,012				
4	WEST VA INC TAX-2012	-384,000		-575	-384,575	
5	WEST VA INC TAX-2013			-290,705	384,000	
6	WVA FRANCHISE - 2012	-156,164		-77,600	-233,764	
7	WVA FRANCHISE - 2013			64,158	254,100	-50
8						
9	REAL & PERS PROP-2011	19,395		-1	19,394	
10	REAL & PERS PROP-2012	45,695		6,252	26,022	
11	REAL & PERS PROP-2013			51,896		
12						
13	WV USE TAX - 2012	4,778		-29	4,749	
14	WV USE TAX - 2013			45,908	41,657	
15	WV EXCISE TAX - 2012	74,480		-478	74,002	
16	WV EXCISE TAX - 2013			352,824	264,411	
17	WV EXCISE TAX - AUDIT	200,000			46,043	
18	UNEMPLOYMENT - 2013	58,454		62,968	61,761	
19	SUBTOTAL West Virginia	-550,374		214,668	557,850	-50
20						
21	STATE OF OHIO:					
22	OHIO FRANCH TAX - 2008					
23	OHIO INCOME TAX					
24	OHIO CAT TAX - 2012	108,000		-103,256	4,744	
25	OHIO CAT TAX - 2013			179,154	131,154	
26	OHIO CAT TAX - Refunds			-114,397	-114,397	
27	SUBTOTAL Ohio	108,000		-38,499	21,501	
28	STATE OF ILLINOIS:					
29	IL INCOME TAX - 2012	-78,471		-130,599	-209,070	
30	IL INCOME TAX - 2013			31,168	593,170	
31	SUBTOTAL Illinois	-78,471		-99,431	384,100	
32	STATE OF LOUISIANA:					
33	LA Franchise Tax					
34						
35	SUBTOTAL Louisiana					
36						
37	STATE OF PA:					
38	PA Gross Receipts Audit			239,325		
39						
40						
41	TOTAL	40,058,941	1,175,988	50,194,344	80,360,752	15,807,838

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 2013/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
(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)	No.
						1
		50				2
-413,012						3
		-4,669			4,094	4
-674,705		-315,709			25,004	5
		-77,486			-114	6
-189,992		60,283			3,875	7
						8
		3,393			-3,394	9
25,925		3,385			2,867	10
51,896					51,896	11
						12
					-29	13
4,251					45,908	14
					-478	15
88,413					352,824	16
153,957						17
59,661		-9,234			72,202	18
-893,606		-339,987			554,655	19
						20
						21
						22
						23
		-103,256				24
48,000		179,154				25
		-99,464			-14,933	26
48,000		-23,566			-14,933	27
						28
		-133,394			2,795	29
-562,002		13,889			17,279	30
-562,002		-119,505			20,074	31
						32
						33
						34
						35
						36
						37
239,325		239,325				38
						39
						40
26,155,820	1,631,437	29,303,011			20,891,333	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 2013/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 Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1						
2	RAILCAR PROP TAX:					
3	Misc States - 2011	-9,805		11,427	1,622	
4	Misc States - 2012	126,989		-41	120,544	
5	Misc States - 2013			30,631	31	
6	MO PROP TAX - 2011	-791		791		
7	NE PROP TAX-2011	3,500		28,010	31,510	
8	WY PROP TAX-2011	58		-58		
9	SUBTOTAL Railcar Prop Tax	119,951		310,085	153,707	
10						
11	STATE OF MISSOURI					
12	UNEMPLOYMENT - 2013	-56,960				
13	MO INCOME TAX - 2012	-408		408		
14	MO INCOME TAX - 2013			-85		
15	MO FRANCHISE	-1,258				
16	SUBTOTAL Missouri	-58,626		323		
17						
18	MISC RTD PROP TX-2011	2,729,964		-2,729,964		
19	MISC RTD PROP TX-2012			2,381,054		
20						
21	FED INCOME TAX FIN-48 -					
22	STATE INCOME TAX FIN-48	2,520,240		-483,542		
23						
24	MICHIGAN LICENSE TAX			100	100	
25	VARIOUS LICENSE TAX			155	155	
26						
27	VARIOUS FRANCHISE TAX					
28						
29	FIT IRS AUDIT	-9,250,043				11,310,246
30	SIT LONG TERM	521,915				
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	40,058,941	1,175,988	50,194,344	80,360,752	15,807,838

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 2013/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
		1,622			9,805	3
6,404		3,078			-3,119	4
30,600					30,631	5
					791	6
					28,010	7
					-58	8
276,329		244,025			66,060	9
						10
						11
-56,960						12
		377			31	13
-85		-92			7	14
-1,258						15
-58,303		285			38	16
						17
					-2,729,964	18
2,381,054					2,381,054	19
						20
						21
2,036,698		-472,363			-11,179	22
						23
		100				24
		155				25
						26
						27
						28
2,060,203						29
521,915						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
26,155,820	1,631,437	29,303,011			20,891,333	41

FOOTNOTE DATA

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

($7,857) - Fuel Tax Credit

$100,045 - Tax Credit Carryforward

($998,246) - NOL Carryforward/FIN48 Reclass

Schedule Page: 262 Line No.: 10 Column: f

$5,403,700 - Reclass to Receivable

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

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

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

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

Schedule Page: 262.2 Line No.: 7 Column: f

($50) - Franchise Tax Expense Transferred from another company

Schedule Page: 262.3 Line No.: 29 Column: f

$11,310,246 - Reclass of Accumulated CFIT - IRS Audit

This Page Intentionally Left Blank

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 2013/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	118,642			4114	79,043	
4	7%						
5	10%	48,011,806			4114	4,851,815	
6							
7							
8	TOTAL	48,130,448				4,930,858	
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							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
39,599			3
			4
43,159,991			5
			6
			7
43,199,590			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

FOOTNOTE DATA

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

Remaining amortization period is 9 years.

This Page Intentionally
Left Blank

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, 2013

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	39,605,314
2	Accrued Vacation, Holiday, and Other Non-Productive	19,824,819
3	Accrued Payroll	5,589,296
4	Payroll Deductions	973,614
5	Miscellaneous Employee Benefits (2 Items)	1,796,195
6	Accrued Workers Compensation	1,237,799
7	Accrued Lease/Rents	30,260,391
8	Accrued Revenue Refunds	3,931,702
9	Control Cash Disbursements	10,935,623
10	Accrued Civil Penalties	6,978,082
11	Spent Nuclear Fuel Disposal Costs	3,343,747
12	Miscellaneous Current & Accrued Liabilities (7 Items)	149,382
13	Environmental Accruals	1,994,053
14	Severance Accruals	21,804
15		
16		
17		
18		
19		
20	TOTAL	126,641,821

CUSTOMER ADVANCES FOR CONSTRUCTION (Account 252)

Line No.	List Advances by department (a)	Balance End of Year (b)
21	None	0
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39	TOTAL	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 2013/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					
2	Amtz Period 12/1989-12/2022	36,818,081	507	9,277,668	5,570,952	33,111,365
3						
4	Pole Attachment Rentals	587,185	454	1,767,887	1,766,287	585,585
5						
6	IPP-System Upgrade Credits	2,810,348			92,456	2,902,804
7						
8	Defd Gain-Fiber Optics Agrmt					
9	In Kind Service-Amrtz thru 2025	4,821,243	411.6	170,564		4,650,679
10						
11	Deferred Revenues-Verizon					
12	Amortized thru March 2023	486,252	451	47,439		438,813
13						
14	Deferred Revenues-KDL					
15	Amortized thru Dec 2022	89,010	451	9,348		79,662
16						
17	Customer Advance Receipts	5,088,462	142	5,088,462	3,796,984	3,796,984
18						
19	Federal Mitigation Deferral (NSR)	2,052,907				2,052,907
20						
21	SEMCO Agreement - MGP Sites	1,000,000				1,000,000
22						
23	Contract Settlement reserves	2,547,316	various	1,984,331	26,515	589,500
24						
25	Environmental Site Remediation	9,360,368	242	2,311,565	334,027	7,382,830
26						
27	City of Sturgis Overpayment				1,026,292	1,026,292
28						
29	Minor Items	2,075	various	314,955	402,181	89,301
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	65,663,247		20,972,219	13,015,694	57,706,722

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 2013/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	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	246,285		30,890
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	246,285		30,890
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				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	246,285		30,890
18	Classification of TOTAL			
19	Federal Income Tax	246,285		30,890
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 2013/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
							3
						215,395	4
							5
							6
							7
						215,395	8
							9
							10
							11
							12
							13
							14
							15
							16
						215,395	17
							18
						215,395	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 2013/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Account 282			
2	Electric	920,003,284	122,025,081	42,123,435
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	920,003,284	122,025,081	42,123,435
6	Non-Utility	342,589		
7	SFAS 109/FIN 48	75,411,333		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	995,757,206	122,025,081	42,123,435
10	Classification of TOTAL			
11	Federal Income Tax	995,757,206	122,025,081	42,123,435
12	State Income Tax			
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
						999,904,930	2
							3
							4
						999,904,930	5
	939					341,650	6
		various	22,716,740	various	32,080,596	84,775,189	7
							8
	939		22,716,740		32,080,596	1,085,021,769	9
							10
	939		22,716,740		32,080,596	1,085,021,769	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 2013/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)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	SFAS 158	77,279,094	491,577	42,724,398
4	Reg Asset - SFAS 143 - ARO	489,889,606	78,684,845	39,134
5	Deferred Cook O&M Restart Cost	9,328,079	22,615,867	11,651,215
6	Nuclear Fuel	28,263,092	59,242,636	54,737,107
7	Mark To Market	13,437,768	1,700,313	8,413,113
8	Other	46,267,256	32,662,607	23,761,906
9	TOTAL Electric (Total of lines 3 thru 8)	664,464,895	195,397,845	141,326,873
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	207,930,716	30,979,947	34,887,915
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	872,395,611	226,377,792	176,214,788
20	Classification of TOTAL			
21	Federal Income Tax	757,667,378	195,397,845	141,326,873
22	State Income Tax	114,728,233	30,979,947	34,887,915
23	Local Income Tax			

NOTES

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				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
						35,046,273	3
						568,535,317	4
						20,292,731	5
						32,768,621	6
						6,724,968	7
2,689,822	1,036,074			various	4,284,566	61,106,271	8
2,689,822	1,036,074				4,284,566	724,474,181	9
							10
							11
							12
							13
							14
							15
							16
							17
6,465,025	5,949,927	various	24,591,060	various	57,012,801	236,959,587	18
9,154,847	6,986,001		24,591,060		61,297,367	961,433,768	19
							20
9,154,847	6,986,001		22,711,680		35,489,656	826,685,172	21
			1,879,380		25,807,711	134,748,596	22
							23

NOTES (Continued)

FOOTNOTE DATA

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

	Balance at Beginning of Year	Balance at End of Year
NON-UTILITY	4,370,427	4,885,525
SFAS 133	463,993	349,280
SFAS 109	203,096,296	231,724,782
Total Line 18	207,930,716	236,959,587

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 2013/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	19,871,620	456	64,671,711	55,609,758	10,809,667
2						
3	Asset Retirement Oblig-Excess Provision SFAS 143	435,716,741	228	62,307,417	223,703,476	597,112,800
4						
5	SNF Trust Funds - Pre 4/83	42,897,941	various	8,825,508	9,343,207	43,415,640
6						
7	Gains on Foreign Currency Derivatives	124,398	403	11,308		113,090
8	Amortz 1/2009 - 12/2023					
9						
10	Clean Coal Technology Rider	773,532	various	1,196,774	430,363	7,121
11	Over-Recovered Expenses					
12						
13	Demand Side Management - Indiana	11,079,687	402,442,908	10,394,172	14,336,004	15,021,519
14						
15	SFAS 109 Deferred FIT	30,896,168	various	3,713,121	82,068	27,265,115
16						
17	Over Recovered Environmental	951,688	182,509	4,057,108	3,105,420	
18	Compliance Tracker					
19						
20	OSS Margin Sharing	7,611,289	447	7,676,258	64,969	
21						
22	River Transportation Selling Price Variance		182	1,760,311	1,760,311	
23						
24	Renewable Energy Surcharge	125,734	various	150,510	24,776	
25						
26	Deregulation - Customer Educ & Transition Filing		254	236,076	236,076	
27						
28	Over Recovered Fuel Costs - Michigan				1,923,886	1,923,886
29						
30	PJM Over Recovered Expenses				13,924,161	13,924,161
31						
32	Major Storm Damage Restoration Reserve		593	1,349,176	1,349,176	
33	Indiana Cause #44075					
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	550,048,798		166,349,450	325,893,651	709,592,999

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) 02/27/14	December 31, 2013

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	Three (3) properties each with original				
5	cost less than $100,000	4,490		48,904	
6					
7					
8	Sale of Non-Utility Property				
9	Six (6) properties each with original	146,620		270,284	
10	cost less than $100,000				
11					
12					
13					
14					
15	Sale of Other Property				
16	Former Breed Plant Land	180,250		580,795	
17	to Wernz LTD				
18					
19	Former Breed Plant Land to J.Kerns,	302,589		3,137,042	
20	R.Kerns, Ceres Farms, Freedom Energy				
21					
22	Fort Wayne NE Service Center Land	7,687		11,713	
23	to City of New Haven				
24					
25					
26					
27	Total Gain	641,636		4,048,738	

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) 02/27/14	December 31, 2013

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	Nothing to report for 2013				
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43	Total Loss	0.00			0.00

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, 2013

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 Expenes	0
5	Total Accounts 415 & 416	0
6		
7	Account 417 - Nonutility Operations	
8	Water Transportation	
9	-Revenues	122,287,805
10	-Expenses - Operation	(102,328,800)
11	-Maintenance	(8,295,053)
12	-Depreciation, Depletion, and Amortization	(1,043,871)
13	-Other	0
14	Total Account 417	10,620,081
15		
16	Account 418 - Nonoperating Rental Income	
17	-Rent Revenue	364,959
18	-Expense	(46,495)
19	-Other	0
20	Total Account 418	318,464
21		
22	Account 418.1 - Equity in Earnings of Subsidiary Companies	8,843
23		
24	Account 419 - Interest and Dividend Income	
25	- Communications Leases	660,195
26	- Margin Interest	201
27	- Dedicated Sales	275,621
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)	December 31, 2013

PARTICULARS CONCERNING CERTAIN OTHER INCOME ACCOUNTS

Line No.	Item (a)	Amount (b)
1		
2	- Other	17,899
3	- Income Taxes	1,508,252
4	- Other	
5	- Other	
6		
7	- Associated Companies	856,304
8		
9	Total Account 419	3,318,472
10		
11		
12	Account 419.1 - Allowance for Funds Used During Contruction	19,943,467
13		
14	Account 421 - Miscellaneous Nonoperating Income	
15		
16	- Power Trading	2,422
17	- Michigan Energy Optimization Carry Charge	4,381
18	- Deregulation Implementation Carrying Charge	26,767
19	MPSC Case U-12652	
20	- Turbine Replacement Carrying Charge	2,218,101
21	- RTO Carrying Charges	251,611
22	- Other	177,597
23	- Rents	36,263
24	- Clean Coal Technology Carrying Charge	208,998
25	- Indiana Life Cycle Management Carry Charge	2,372,985
26	- Michigan Life Cycle Management Carry Charge	133,907
27	- Michigan Lost Net Revenue	6,902
28	- Michigan Renewable Energy Carry Charge	11,451
29		
30	Total Account 421	5,451,385
31		
32	Account 421.1 - Gain on Disposition of Property	4,048,738
33		
34	Account 421.2 - Loss on Disposition of Property	0
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46		
47	Total Other Income	43,709,450

275621

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 31,2013

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 previous 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	121,234,661	117,523,060
3	(442) Commercial and Industrial Sales		
4	Small (or Commercial)	74,789,100	74,852,074
5	Large (or Industrial)	63,296,998	61,517,393
6	(444) Public Street and Highway Lighting	1,359,808	1,426,349
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	260,680,567	255,318,876
13			
14	(447) Sales for Resale	44,086,658	36,882,273
15	TOTAL Sales of Electricity	304,767,225	292,201,149
16			
17	(Less) (449.1) Provision for Rate Refunds	0	0
18	TOTAL Revenue Net of Provision for Refunds	**304,767,225**	**292,201,149**
19	Other Operating Revenues		
20	(450) Forfeited Discounts	728,907	726,403
21	(451) Miscellaneous Service Revenues	763,027	738,140
22	(453) Sales of Water and Water Power		
23	(454) Rent from Electric Property	1,000,120	1,067,940
24	(455) Interdepartmental Rents		
25	(456) Other Electric Revenues	8,386,112	6,310,218
26			
27			
28			
29			
30	TOTAL Other Operating Revenues	10,878,166	8,842,701
31			
32	TOTAL Electric Operating Revenues	**315,645,391**	**301,043,850**

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 31,2013

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		Line No.
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number or Previous Year (g)	
				1
1,214,720	1,217,370	109,111	109,019	2
				3
808,760	818,042	17,485	17,410	4
813,178	801,640	970	975	5
11,111	11,182	342	341	6
				7
				8
				9
				10
				11
2,847,769	2,848,234	127,908	127,745	12
				13
608,277	623,897	5	5	14
3,456,046 **	3,472,131	127,913	127,750	15
				16
				17
3,456,046	3,472,131	127,913	127,750	18

* Include ($1,357,888) unbilled revenues.

** Includes (15,352) 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)	December 31, 2013

CUSTOMER CHOICE ELECTRIC OPERATING REVENUES

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	Customer Choice Sales of Electricity		
2	Residential Sales	$ 1,136	$ 4,831
3	Commercial and Industrial Sales		
4	Small (or Commercial)	$ 300,693	$ 932,786
5	Large (or Industrial)	$ 528,012	$ 1,228,514
6			
7			
8			
9			
10			
11			
12	TOTAL Customer Choice Sales	$ 829,841	$ 2,166,131
13			
14			
15	TOTAL Sales of Electricity	$ 829,841	$ 2,166,131
16			
17			
18	TOTAL Revenue Net of Provision for Refunds	**$ 829,841**	**$ 2,166,131**
19	Other Operating Revenues		
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30	TOTAL Other Operating Revenues		
31			
32	TOTAL Electric Operating Revenues	**$ 829,841**	**$ 2,166,131**

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, 2013

CUSTOMER CHOICE ELECTRIC OPERATING REVENUES (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		Line No.
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number or Previous Year (g)	
				1
16	101	4	12	2
				3
6,795	24,097	31	43	4
10,324	25,573	13	14	5
				6
				7
				8
				9
				10
				11
17,135	49,771	48	69	12
				13
				14
17,135	49,771	48	69	15
				16
				17
17,135	49,771	48	69	18

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 31,2013

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, avg 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	1,104,394	112,941,833	101,903	10,838	0.1023
3	RESIDENTIAL SERVICE TOD	84,029	7,827,894	4,784	17,565	0.0932
4	RESIDENTIAL OFF PEAK ENERGY	14,329	1,143,128	575	24,920	0.0798
5	RESIDENTIAL SVC OPT SENIOR	10,669	896,841	1,849	5,770	0.0841
6	OUTDOOR LIGHTING	3,911	788,231			0.2015
7	UNBILLED	(2,612)	(405,331)			0.1552
8	UNRECOVERED FUEL		(1,957,935)			
9	Total Residential Sales	1,214,720	121,234,661	109,111	11,133	0.0998
10						
11	442 Commercial Sales					
12	SMALL GENERAL SERVICE	80,889	9,931,616	12,766	6,336	0.1228
13	MEDIUM GENERAL SERVICE	366,158	36,138,715	3,412	107,315	0.0987
14	MEDIUM GENERAL SERVICE TOD	8,462	728,366	149	56,792	0.0861
15	LARGE GENERAL SERVICE	170,646	13,947,620	158	1,080,038	0.0817
16	LARGE POWER	104,853	7,732,937	4	26,213,250	0.0738
17	ELECTRIC HEATING GENERAL	3,643	348,140	59	61,746	0.0956
18	ELECTRIC HEATING SCHOOLS	8,078	686,077	17	475,176	0.0849
19	MUNICIPAL & SCHOOL SERVICE	27,613	2,739,797	198	139,460	0.0992
20	IRRIGATION SERVICE	9,529	905,317	471	20,231	0.0950
21	WATER & SEWAGE SERVICE	25,398	2,053,805	249	102,000	0.0809
22	STREETLIGHTING SERVICE	20	2,091	2	10,000	0.1046
23	RESIDENTIAL SERVICE	0	0	0	0	0.0000
24	OUTDOOR LIGHTING	6,197	1,076,992			0.1738
25	UNBILLED	(2,726)	(352,776)			0.1294
26	UNRECOVERED FUEL		(1,149,597)			
27	Total Commercial Sales	808,760	74,789,100	17,485	46,255	0.0925
28						
29	442 Industrial Sales					
30	SMALL GENERAL SERVICE	3,257	377,542	395	8,246	0.1159
31	MEDIUM GENERAL SERVICE	187,611	17,722,144	511	367,145	0.0945
32	MEDIUM GENERAL SERVICE TOD	71	6,639	1	71,000	0.0935
33	LARGE GENERAL SERVICE	141,555	11,402,593	40	3,538,875	0.0806
34	LARGE POWER	489,405	35,338,476	20	24,470,250	0.0722
35	ELECTRIC HEATING GENERAL	424	40,966	3	141,333	0.0966
36	OUTDOOR LIGHTING	853	135,026			0.1583
37	UNBILLED	(9,998)	(597,864)			0.0598
38	UNRECOVERED FUEL		(1,128,524)			
39	Total Industrial Sales	813,178	63,296,998	970	838,328	0.0778

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 31,2013

SALES OF ELECTRICITY BY RATE SCHEDULES

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	444 Public Street & Highway Light					
2	SMALL GENERAL SERVICE	511	77,550	161	3,174	0.1518
3	MEDIUM GENERAL SERVICE	93	9,467	2	46,500	0.1018
4	SL CUST OWNED SYS	523	45,199	7	74,714	0.0864
5	SL CUST OWNED SYS METERED	552	34,888	30	18,400	0.0632
6	MUNICIPAL & SCHOOL	145	16,720	6	24,167	0.1153
7	ENERGY CONSERV LIGHTING	5,044	648,103	88	57,318	0.1285
8	STREETLIGHTING SERVICE	4,155	523,467	48	86,563	0.1260
9	OUTDOOR LIGHTING	105	17,977			0.1712
10	UNBILLED	(17)	(1,916)			0.1127
11	UNRECOVERED FUEL		(11,647)			
12	Total Public Street & Highway Light	11,111	1,359,808	342	32,488	0.1224
13						
14	Fuel Clause (see footnote)					
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49						
50						
51						
52						
53						
54						
55	Total Billed	2,863,121	262,038,455	127,908	22,384	0.0915
56	Total Unbilled Rev. (See Instr. 6)	(15,352)	(1,357,888)			0.0885
57	TOTAL	**2,847,769**	**260,680,567**	**127,908**	22,264	0.0915

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 31,2013

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)	
304.1	14	a	440 Residential Sales	
			RESIDENTIAL SERVICE	(6,249,879)
			RESIDENTIAL SERVICE TOD	(475,518)
			OUTDOOR LIGHTING	(22,129)
			RESIDENTIAL OFF PEAK ENERGY STORAGE	(81,133)
			RESIDENTIAL SVC OPT SENIOR CITIZEN	(60,389)
			RESIDENTIAL TOTAL	(6,889,048)
			442 Commercial Sales	
			SMALL GENERAL SERVICE	(457,657)
			MEDIUM GENERAL SERVICE	(2,068,947)
			MEDIUM GENERAL SERVICE TOD	(47,895)
			LARGE GENERAL SERVICE	(947,518)
			LARGE POWER	(564,636)
			ELECTRIC HEATING GENERAL	(20,607)
			ELECTRIC HEATING SCHOOLS	(41,517)
			MUNICIPAL & SCHOOL SERVICE	(155,097)
			IRRIGATION SERVICE	(53,990)
			WATER & SEWAGE SERVICE	(143,740)
			OUTDOOR AND STREET LIGHTING	(35,187)
			COMMERCIAL TOTAL	(4,536,791)
			442 Industrial Sales	
			SMALL GENERAL SERVICE	(18,386)
			MEDIUM GENERAL SERVICE	(1,046,846)
			MEDIUM GENERAL SERVICE TOD	(404)
			LARGE GENERAL SERVICE	(787,106)
			LARGE POWER	(2,685,134)
			ELECTRIC HEATING GENERAL	(2,402)
			OUTDOOR AND STREET LIGHTING	(4,842)
			INDUSTRIAL TOTAL	(4,545,120)
			444 Public Street & Highway Light	
			SMALL GENERAL SERVICE	(2,890)
			MEDIUM GENERAL SERVICE	(524)
			SL CUST OWNED SYS	(26,493)
			SL CUST OWNED SYS METERED	(3,123)
			MUNICIPAL & SCHOOL SERVICE	(818)
			OUTDOOR AND STREET LIGHTING	(594)
			ENERGY CONSERVE LIGHTING	(28,554)
			PUBLIC STREET & HIGHWAY LIGHT TOTAL	(62,996)
			GRAND TOTAL	**(16,033,955)**

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)	December 31, 2013

CUSTOMER CHOICE SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, avg 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	24	$ 1,705	4	6,000	$ 0.07104
3	Unbilled	(8)	$ (569)			$ 0.07113
4	Total Residential Sales	16	$ 1,136			$ 0.07100
5						
6						
7	442 Commercial Sales					
8	Electric Heating General	2	$ 182		0	$ 0.09100
9	Electric Heating Schools	237	$ 18,121	2	118,500	$ 0.07646
10	Small General Service	26	$ 2,081	13	2,000	$ 0.08004
11	Medium General Service	477	$ 29,078	10	47,700	$ 0.06096
12	Large General Service	3,251	$ 154,185	4	812,750	$ 0.04743
13	Large Power	5,095	$ 197,302		0	$ 0.03872
14	Municipal and School Service	216	$ 13,755	2	108,000	$ 0.06368
15	Misc	7	$ 987		0	$ 0.14100
16	Unbilled	(2,517)	$ (114,998)			$ 0.04569
17	Total Commercial Sales	6,794	$ 300,693			$ 0.04426
18						
19						
20	442 Industrial Sales					
21	Small General Service	9	$ 500			$ 0.05556
22	Medium General Service	2,525	$ 150,410	7	360,714	$ 0.05957
23	Large General Service	2,248	$ 129,385	3	749,333	$ 0.05756
24	Large Power	8,914	$ 423,562	3	2,971,333	$ 0.04752
25	Unbilled	(3,372)	$ (175,845)			$ 0.05215
26	Total Industrial Sales	10,324	$ 528,012			$ 0.05114
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42	Total Billed	23,031	$ 1,121,253	48	479,813	$ 0.04868
43	Total Unbilled Rev. (See Instr. 6)	(5,897)	$ (291,412)			$ 0.04942
44	TOTAL	**17,134**	**$ 829,841**	**48**	356,958	$ 0.04843

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 2013/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 Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	CITY OF AUBURN	RQ	Note 2			
2	CITY OF BLUFFTON	RQ	IMPCO#104			
3	CITY OF DOWAGIAC, MI	RQ	Note1			
4	CITY OF GARRETT	RQ	IMPCO#109			
5	CITY OF MISHAWAKA	RQ	IMPCO#102			
6	CITY OF NILES	RQ	IMPCO#106			
7	CITY OF SOUTH HAVEN	RQ	IMPCO#108			
8	CITY OF STURGIS	RQ	IMPCO#107			
9	INDIANA MUNICIPAL POWER AGENCY	RQ	IMPCO#101			
10	PJM TRANSMISSION FOR RQ	RQ	Various			
11	TOWN OF AVILA	RQ	IMPCO#105			
12	TOWN OF NEW CARLISLE	RQ	IMPCO#103			
13	TOWN OF WARREN	RQ	IMPCO#110			
14	VILLAGE OF PAW PAW	RQ	IMPCO#111			
	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 ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
449,681	10,859,352	17,902,191		28,761,543	1
314,520	13,231,269	7,493,111		20,724,380	2
69,272	3,131,560	1,678,027		4,809,587	3
91,643	4,193,490	2,237,893		6,431,383	4
619,372	28,267,192	14,541,044		42,808,236	5
135,029	6,354,409	3,173,030		9,527,439	6
139,714	6,349,415	3,329,356		9,678,771	7
220,516	9,998,410	5,362,470		15,360,880	8
1,640,808	56,741,131	36,549,540		93,290,671	9
			-25,756,655	-25,756,655	10
35,389	1,577,679	847,105		2,424,784	11
11,389	565,792	302,598		868,390	12
18,925	901,386	493,224		1,394,610	13
43,746	2,078,314	1,207,893		3,286,207	14
5,030,489	200,538,047	124,886,677	-25,756,655	299,668,069	
14,691,572	23,361,011	470,430,485	0	493,791,496	
19,722,061	**223,899,058**	**595,317,162**	**-25,756,655**	**793,459,565**	

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 2013/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 Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	WABASH VALLEY POWER ASSN INC.	RQ	IMPCO#112			
2	ADJUSTMENT	OS	See footnote			
3	AEP SERVICE CORPORATION	OS	17			
4	AEP SERVICE CORPORATION	OS	20			
5	ALLEGHENY ELECTRIC COOPERATIVE	OS	Note1			
6	AMEREN CILCO	OS	Note1			
7	AMEREN ENERGY MARKETING	OS	Note1			
8	AMERICAN MUNICIPAL POWER-OHIO	OS	Note1			
9	AMERICAN POWERNET MANAGEMENT	OS	Note1			
10	ASSOCIATED ELECT COOPERATIVE	OS	Note1			
11	B.P. ENERGY COMPANY	OS	Note1			
12	BARCLAYS BANK PLC	OS	Note1			
13	BEECH RIDGE ENERGY LLC	OS	Note1			
14	BP AMOCO	OS	Note1			
	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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
1,240,485	56,288,648	29,769,195		86,057,843	1
		72,247		72,247	2
8,485,017	21,857,120	214,937,863		236,794,983	3
12,983		396,491		396,491	4
3,634		177,547		177,547	5
18,452		618,473		618,473	6
-10,940		-209,676		-209,676	7
35,410	122,897	1,850,251		1,973,148	8
15,133		624,891		624,891	9
-1,857		-61,117		-61,117	10
-3,339		-298,607		-298,607	11
5,809		-74,925		-74,925	12
		-38,456		-38,456	13
		-46,450		-46,450	14
5,030,489	200,538,047	124,886,677	-25,756,655	299,668,069	
14,691,572	23,361,011	470,430,485	0	493,791,496	
19,722,061	**223,899,058**	**595,317,162**	**-25,756,655**	**793,459,565**	

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 2013/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 Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	BUCKEYE RURAL ELECTRIC ADMIN	OS	Note1			
2	CALIFORNIA ISO	OS	Note 1			
3	CALPINE POWER SERVICE COMPANY	OS	Note1			
4	CITIGROUP ENERGY INC.	OS	Note1			
5	CITY OF BANGOR, WISCONSIN	OS	Note 1			
6	CITY OF BARRON, WISCONSIN	OS	Note 1			
7	CITY OF BATAVIA	OS	Note1			
8	CITY OF BLOOMER, WISCONSIN	OS	Note 1			
9	CITY OF COLUMBUS	OS	Note1			
10	CITY OF CORNELL, WISCONSIN	OS	Note 1			
11	CITY OF CROSWELL, MI	OS	Note1			
12	CITY OF KIRKWOOD, MISSOURI	OS	Note1			
13	CITY OF MEDFORD	OS	Note1			
14	CITY OF RICE LAKE UTILITIES	OS	Note 1			
	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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
64,607		19,603,997		19,603,997	1
		8		8	2
-333		-11,356		-11,356	3
316		13,267		13,267	4
5,863		364,673		364,673	5
17,451		1,066,279		1,066,279	6
5,303		226,712		226,712	7
11,320		692,202		692,202	8
177,341		11,887,192		11,887,192	9
3,011		183,633		183,633	10
8,609		427,500		427,500	11
5,303		277,092		277,092	12
26,841		1,596,051		1,596,051	13
33,836		2,097,629		2,097,629	14
5,030,489	200,538,047	124,886,677	-25,756,655	299,668,069	
14,691,572	23,361,011	470,430,485	0	493,791,496	
19,722,061	**223,899,058**	**595,317,162**	**-25,756,655**	**793,459,565**	

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 2013/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 Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	CITY OF SHELBY	OS	Note1			
2	CITY OF SPOONER, WISCONSIN	OS	Note 1			
3	CITY OF WAKEFIELD, WISCONSIN	OS	Note 1			
4	CITY OF WESTERVILLE	OS	Note1			
5	CLEVELAND TOLEDO OH PA ELECTRIC	OS	Note1			
6	COMMONWEALTH EDISON COMPANY	OS	Note1			
7	CONOCO INC.	OS	Note1			
8	CONSTELLATION ENGY COMMODITIES	OS	Note1			
9	COOK INLET ENERGY SUPPLY LP	OS	Note1			
10	DAIRYLAND POWER COOPERATIVE	OS	Note1			
11	DAMAN QUATTRO LIMITED	OS	Note 1			
12	DB ENERGY TRADING LLC	OS	Note1			
13	DELMARVA POWER & LIGHT	OS	Note 1			
14	DP&L POWER SERVICES	OS	Note1			
	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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
5,731		419,136		419,136	1
7,059		428,840		428,840	2
2,981		178,259		178,259	3
102,065		7,845,468		7,845,468	4
	57,253	-985		56,268	5
50,538		1,622,334		1,622,334	6
		103,358		103,358	7
-181		-24,663		-24,663	8
		-201,937		-201,937	9
		-697		-697	10
		-98		-98	11
		-256,157		-256,157	12
		-4,228		-4,228	13
		350,594		350,594	14
5,030,489	200,538,047	124,886,677	-25,756,655	299,668,069	
14,691,572	23,361,011	470,430,485	0	493,791,496	
19,722,061	**223,899,058**	**595,317,162**	**-25,756,655**	**793,459,565**	

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 2013/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)	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	DTE ENERGY TRADING INC.	OS	Note1			
2	DUKE ENERGY CAROLINAS, LLC	OS	Note1			
3	DUKE ENERGY OHIO, INC	OS	Note1			
4	EAST KY POWER CO-OP POWER MKTG	OS	Note1			
5	EASTON UTILITIES	OS	Note1			
6	EDF TRADING NORTH AMERICA LLC	OS	Note1			
7	EDISON MISSION MKTG & TRADING	OS	Note1			
8	ENDURE ENERGY, LLC	OS	Note1			
9	ENERGY AMERICA, LLC	OS	Note1			
10	ENG MKTG, DIV OF AMERADA HESS	OS	Note1			
11	ENTERGY POWER SERV	OS	Note1			
12	EXELON GENERATION - POWER TEAM	OS	Note1			
13	FIRSTENERGY TRADING SERVICES	OS	Note1			
14	HARRISON RURAL ELECTRIFICATION	OS	Note1			
	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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
		-46,791		-46,791	1
		-2,722		-2,722	2
33,176		1,617,558		1,617,558	3
90,757		3,485,683		3,485,683	4
5,437		236,282		236,282	5
41,421		1,698,942		1,698,942	6
	100,837			100,837	7
		-1,489		-1,489	8
		214,656		214,656	9
		249,799		249,799	10
		-5,496		-5,496	11
-11,315		-5,279,589		-5,279,589	12
287,827		15,282,278		15,282,278	13
21,050		1,633,475		1,633,475	14
5,030,489	200,538,047	124,886,677	-25,756,655	299,668,069	
14,691,572	23,361,011	470,430,485	0	493,791,496	
19,722,061	**223,899,058**	**595,317,162**	**-25,756,655**	**793,459,565**	

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 2013/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 Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	INDIANAPOLIS POWER & LIGHT CO	OS	Note1			
2	INTEGRYS ENERGY SERVICES, INC	OS	Note1			
3	INTERSTATE GAS SUPPLY, INC.	OS	Note 1			
4	INTERSTATE POWER & LIGHT CO	OS	Note1			
5	J ARON & COMPANY	OS	Note1			
6	JP MORGAN VENTURES ENERGY CORP	OS	Note1			
7	KANSAS CITY POWER & LIGHT CO	OS	Note1			
8	LETTERKENNY INDUSTRIL DEV AUTH	OS	Note1			
9	MICHIGAN PUBLIC POWER AGENCY	OS	Note1			
10	MIDAMERICAN ENERGY	OS	Note1			
11	MIDWEST ISO	OS	Note1			
12	MIZUHO SECURITIES USA INC	OS	Note1			
13	MORGAN STANLEY CAPT.	OS	Note1			
14	NC ELECTRIC MEMBERSHIP CORP.	OS	Note1			
	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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
	4,174			4,174	1
		133,063		133,063	2
4,809		175,503		175,503	3
		9,530		9,530	4
181,126		5,622,138		5,622,138	5
14,949		-1,084,609		-1,084,609	6
-717		-24,127		-24,127	7
6,461		407,508		407,508	8
13,382		897,416		897,416	9
		35,337		35,337	10
-403,356		-14,669,001		-14,669,001	11
		2,033,309		2,033,309	12
824		-1,177,473		-1,177,473	13
181,026		7,789,346		7,789,346	14
5,030,489	200,538,047	124,886,677	-25,756,655	299,668,069	
14,691,572	23,361,011	470,430,485	0	493,791,496	
19,722,061	**223,899,058**	**595,317,162**	**-25,756,655**	**793,459,565**	

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 2013/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 Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	NEXTERA ENERGY POWER MKTG LLC	OS	Note1			
2	NOBLE AMERICAS GAS AND POWER	OS	Note1			
3	NRG POWER MARKETING INC.	OS	Note1			
4	OLD DOMINION ELEC.	OS	Note1			
5	OSS OVER/UNDER JULY 11 - JUNE 12	OS	Note 1			
6	OTTER TAIL POWER COMPANY	OS	Note1			
7	OVEC POWER SCHEDULING	OS	Note 1			
8	PARIBAS	OS	Note1			
9	PAULDING WIND FARM II, LLC	OS	Note 1			
10	PJM INTERCONNECTION	OS	Note1			
11	POTOMAC ELECTRIC POWER COMPANY	OS	Note1			
12	PP&L ENERGY PLUS CO.	OS	Note 1			
13	PPL ELECTRIC UTILITIES CORP	OS	Note1			
14	PRAIRIE POWER, INC.	OS	Note1			
	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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
996		566,944		566,944	1
		104,554		104,554	2
8,755	11,691	201,465		213,156	3
167		6,075		6,075	4
		12,019,843		12,019,843	5
		-10		-10	6
		49		49	7
		15		15	8
		-47,624		-47,624	9
4,878,343	1,206,700	162,537,189		163,743,889	10
21,355		1,512,137		1,512,137	11
		567,744		567,744	12
415		27,743		27,743	13
13,004		702,628		702,628	14
5,030,489	200,538,047	124,886,677	-25,756,655	299,668,069	
14,691,572	23,361,011	470,430,485	0	493,791,496	
19,722,061	**223,899,058**	**595,317,162**	**-25,756,655**	**793,459,565**	

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 2013/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 Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	PRAIRIELAND ENERGY INCORPORATE	OS	Note1			
2	SEMPRA ENERGY SOLUTIONS, LLC	OS	Note1			
3	SOUTHERN COMPANY	OS	Note1			
4	THE BOROUGH OF PITCAIRN, PA	OS	Note1			
5	THE ENERGY AUTHORITY	OS	Note1			
6	TOWN OF BERLIN, MARYLAND	OS	Note1			
7	TOWN OF HAGERSTOWN, INDIANA	OS	Note1			
8	TVA BULK POWER TRADING	OS	Note1			
9	UBS AG, LONDON BRANCH	OS	Note 1			
10	UBS SECURITIES LLC	OS	Note1			
11	UGI UTILITIES	OS	Note 1			
12	UNION ELECTRIC COMPANY	OS	Note1			
13	UNION POWER PARTNERS	OS	Note1			
14	VILLAGE OF BETHEL OHIO	OS	Note1			
	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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
18,633		628,625		628,625	1
		-23,498		-23,498	2
4,153		158,029		158,029	3
2,675		125,787		125,787	4
190		7,637		7,637	5
4,049		258,156		258,156	6
4,832		301,447		301,447	7
1,655		73,407		73,407	8
		-106,758		-106,758	9
		-3,695,844		-3,695,844	10
6,002		309,538		309,538	11
		57,719		57,719	12
-3,915		-122,079		-122,079	13
6,064		314,188		314,188	14
5,030,489	200,538,047	124,886,677	-25,756,655	299,668,069	
14,691,572	23,361,011	470,430,485	0	493,791,496	
19,722,061	**223,899,058**	**595,317,162**	**-25,756,655**	**793,459,565**	

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 2013/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 Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	VILLAGE OF CADOTT, WISCONSIN	OS	Note 1			
2	VILLAGE OF GLOUSTER	OS	Note1			
3	VILLAGE OF HAMERSVILLE, OHIO	OS	Note1			
4	VILLAGE OF RIPLEY OHIO	OS	Note1			
5	VILLAGE OF SEBEWAING, MI	OS	Note1			
6	VILLAGE OF TREMPEALEAU, WISCONSIN	OS	Note 1			
7	WASHINGTON GAS ENERGY SERVICES	OS	Note1			
8	WESTAR ENERGY INC.	OS	Note1			
9	WILDCAT WIND FARM	OS	Note 1			
10	WISCONSIN POWER & LIGHT	OS	Note1			
11	WOLVERINE POWER SUPPLY COOP	OS	Note1			
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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
2,957		183,994		183,994	1
269		49,041		49,041	2
1,108		66,446		66,446	3
4,021		208,828		208,828	4
10,015		474,022		474,022	5
3,498		219,879		219,879	6
48,397		2,067,078		2,067,078	7
-6,282		-218,352		-218,352	8
		-39,099		-39,099	9
14,833		523,206		523,206	10
90,563	339	4,347,175		4,347,514	11
					12
					13
					14
5,030,489	200,538,047	124,886,677	-25,756,655	299,668,069	
14,691,572	23,361,011	470,430,485	0	493,791,496	
19,722,061	**223,899,058**	**595,317,162**	**-25,756,655**	**793,459,565**	

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

NOTE 2 - I&M FERC Electric Tariff, Original Vol. No. 7, SA No. 013

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

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

Schedule Page: 310 Line No.: 3 Column: c

NOTE 1: FERC Electric Tariff, Second Substitute Volume No. 5 (1st quarter 2009) FERC Electric Tariff, First Revised Volume No. 5 (2nd, 3rd, and 4th quarter 2009)

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

PJM transmission expenses related to wholesale customers

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

Amount represents transmission services and related charges.

Schedule Page: 310.1 Line No.: 2 Column: a

Reclass between 447 and 555 accounts to incorporate certain trading/marketing activity. The amounts represented on Page 310-11 and 326-27 are equal and off-setting.

Schedule Page: 310.1 Line No.: 3 Column: a

Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company and Ohio Power Company are associated companies and were members of the American Electric Power System Pool, whose electric facilities are interconnected at a number of points and are operated in a fully coordinated manner on a system pool basis. Power transactions between the members of the AEP System Pool were governed by the terms of the interconnection agreement dated July 6, 1951, as amended, and were processed by American Electric Power Service. See Notes to Financial Statements for discussion of termination of interconnection agreement as of 12/31/2013.

Schedule Page: 310.1 Line No.: 4 Column: a

Affiliated Company transactions related to the System Integration Agreement. See pages 122-123 (Notes to Financial Statements) Related Party Transactions - System Integration Agreement for additional information.

Schedule Page: 310.6 Line No.: 7 Column: a

An affiliated company.

This Page Intentionally
Left Blank

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, 2013

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived 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	6,269,752	6,068,133
5	(501) Fuel	271,220,084	286,390,555
6	(502) Steam Expenses	7,003,491	9,585,347
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred - **CR.**		
9	(505) Electric Expenses	1,661,709	1,571,953
10	(506) Miscellaneous Steam Power Expenses	7,955,966	16,909,050
11	(507) Rents	70,143,009	70,141,543
12	(509) Allowances	13,587,258	17,533,485
13	TOTAL Operation *(Enter Total of Lines 4 thru 12)*	377,841,269	408,200,066
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	3,655,468	3,738,924
16	(511) Maintenance of Structures	1,514,111	2,120,896
17	(512) Maintenance of Boiler Plant	18,867,611	15,794,382
18	(513) Maintenance of Electric Plant	6,265,980	3,851,616
19	(514) Maintenance of Miscellaneous Steam Plant	2,089,912	1,879,545
20	TOTAL Maintenance *(Enter Total of Lines 15 thru 19)*	32,393,082	27,385,363
21	TOTAL Power Production Expenses-Steam Power *(Total of lines 13 & 20)*	410,234,351	435,585,429
22	**B. Nuclear Power Generation**		
23	Operation		
24	(517) Operation Supervision and Engineering	18,410,520	16,879,511
25	(518) Fuel	150,381,935	159,132,153
26	(519) Coolants and Water	4,432,531	5,310,279
27	(520) Steam Expenses	9,470,954	9,761,297
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred - **CR**		
30	(523) Electric Expenses	1,842,260	2,212,555
31	(524) Miscellaneous Nuclear Power Expenses	90,133,559	86,689,774
32	(525) Rents	0	0
33	TOTAL Operation *(Enter Total of lines 24 thru 32)*	274,671,759	279,985,569
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	10,609,249	12,052,181
36	(529) Maintenance of Structures	3,504,124	2,520,038
37	(530) Maintenance of Reactor Plant Equipment	66,680,026	62,577,064
38	(531) Maintenance of Electric Plant	11,096,849	2,872,540
39	(532) Maintenance of Miscellaneous Nuclear Plant	17,551,934	18,320,357
40	TOTAL Maintenance *(Enter Total of Lines 35 thru 39)*	109,442,182	98,342,180
41	TOTAL Power Production Expenses-Nuclear Power *(Total of lines 33 & 40)*	384,113,941	378,327,749
42	**C. Hydraulic Power Generation**		
43	Operation		
44	(535) Operation Supervision and Engineering	456,817	614,674
45	(536) Water for Power	0	0
46	(537) Hydraulic Expenses	18,038	28,282
47	(538) Electric Expenses	146	617
48	(539) Miscellaneous Hydraulic Power Generation Expenses	820,503	1,068,418
49	(540) Rents	0	0
50	TOTAL Operation *(Enter Total of Lines 44 thru 49)*	1,295,504	1,711,991
51	Maintenance		
52	(541) Maintenance Supervision and Engineering	124,727	118,972
53	(542) Maintenance of Structures	456,545	368,042
54	(543) Maintenance of Reservoirs, Dams, and Waterways	404,311	716,830
55	(544) Maintenance of Electric Plant	327,657	420,584
56	(545) Maintenance of Miscellaneous Hydraulic Plant	36,701	36,304
57	TOTAL Maintenance *(Total of Lines 52 thru 56)*	1,349,941	1,660,732

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, 2013

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (cont'd)

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

Line No.	Account (a)	Amt. For Current Year (b)	Amt. For Previous Year (c)
58	**C. Hydraulic Power Generation (Continued)**		
59	TOTAL Pwr. Production Expenses-Hydraulic Pwr.*(Total of lines 50 & 57)*	2,645,445	3,372,723
60	**D. Other Power Generation**		
61	Operation		
62	(546) Operation Supervision and Engineering	47,435	39,699
63	(547) Fuel	0	64
64	(548) Generation Expenses	22,564	(15)
65	(549) Miscellaneous Other Power Generation Expenses	7,833	14,554
66	(550) Rents		
67	TOTAL Operation *(Total of Lines 62 thru 66)*	77,832	54,302
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant	2	(19)
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	0	0
73	TOTAL Maintenance *(Total of Lines 69 thru 72)*	2	(19)
74	TOTAL Pwr. Production Expenses-Other Power *(Total of Lines 67 & 73)*	77,834	54,283
75	**E. Other Power Supply Expenses**		
76	(555) Purchased Power	618,236,014	530,902,651
77	(556) System Control and Load Dispatching	1,488,784	1,616,100
78	(557) Other Expenses	3,657,105	4,996,816
79	Total Other Power Supply Expenses *(Total of Lines 76 thru 78)*	623,381,903	537,515,567
80	Total Pwr. Production Expenses *(Total of lines 21, 41, 59, 74 & 79)*	1,420,453,474	1,354,855,751
81	**2. TRANSMISSION EXPENSES**		
82	Operation		
83	(560) Operation Supervision and Engineering	2,748,922	2,141,577
84	(561) Load Dispatching		
85	(561.1) Load Dispatch-Reliability	29,851	17,920
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,451,031	1,172,559
87	(561.3) Load Dispatch-Transmission Service and Scheduling	0	(246)
88	(561.4) Scheduling, System Control and Dispatch Services	3,174,684	5,531,795
89	(561.5) Reliability, Planning and Standards Development	390,782	327,367
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	746,285	1,083,397
93	(562) Station Expenses	642,820	790,946
94	(563) Overhead Lines Expenses	254,798	151,087
95	(564) Underground Lines Expenses	(11,203)	0
96	(565) Transmission of Electricity by Others	28,944,437	13,667,883
97	(566) Miscellaneous Transmission Expenses	2,712,985	3,551,568
98	(567) Rents	16,122	28,321
99	TOTAL Operation *(Total of Lines 83 thru 98)*	41,101,514	28,464,174
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	66,910	103,039
102	(569) Maintenance of Structures	26,575	60,724
103	(569.1) Maintenance of Computer Hardware	66,794	122,732
104	(569.2) Maintenance of Computer Software	900,944	623,152
105	(569.3) Maintenance of Communication Equipment	82,377	190,134
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	3,953,919	3,838,482
108	(571) Maintenance of Overhead Lines	8,754,308	6,623,668
109	(572) Maintenance of Underground Lines	0	(6)
110	(573) Maintenance of Miscellaneous Transmission Plant	46,721	0
111	TOTAL Maintenance *(Total of Lines 101 thru 110)*	13,898,548	11,561,925
112	TOTAL Transmission Expenses *(Total of Lines 99 & 111)*	55,000,062	40,026,099
113	**3. REGIONAL MARKET EXPENSES**		
114	Operation		

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, 2013

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (cont'd)

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

Line No.	Account (a)	Amt. For Current Year (b)	Amt. For Previous Year (c)
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	3,258,456	5,602,674
122	(575.8) Rents		
123	TOTAL Operation *(Total of Lines 115 thru 122)*	3,258,456	5,602,674
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	TOTAL Maintenance *(Total of Lines 125 thru 129)*	0	0
131	TOTAL Distribution Expenses *(Total of Lines 123 & 130)*	3,258,456	5,602,674
132	**4. DISTRIBUTION EXPENSES**		
133	Operation		
134	(580) Operation Supervision and Engineering	2,941,346	3,038,309
135	(581) Load Dispatching	1,146,832	1,129,568
136	(582) Station Expenses	736,301	1,139,861
137	(583) Overhead Line Expenses	450,598	279,332
138	(584) Underground Line Expenses	2,124,332	1,950,941
139	(585) Street Lighting and Signal System Expenses	109,589	135,955
140	(586) Meter Expenses	(86,823)	(450,431)
141	(587) Customer Installations Expenses	655,069	576,407
142	(588) Miscellaneous Expenses	13,614,779	14,868,403
143	(589) Rents	1,447,588	1,827,905
144	TOTAL Operation *(Total of Lines 134 thru 143)*	23,139,611	24,496,250
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	46,859	159,921
147	(591) Maintenance of Structures	43,813	103,512
148	(592) Maintenance of Station Equipment	2,290,137	2,902,721
149	(593) Maintenance of Overhead Lines	26,661,835	23,066,871
150	(594) Maintenance of Underground Lines	1,971,324	1,836,091
151	(595) Maintenance of Line Transformers	150,931	450,603
152	(596) Maintenance of Street Lighting and Signal Systems	415,017	469,120
153	(597) Maintenance of Meters	281,296	202,507
154	(598) Maintenance of Miscellaneous Distribution Plant	465,891	365,173
155	TOTAL Maintenance *(Total of Lines 146 thru 154)*	32,327,103	29,556,519
156	TOTAL Distribution Expenses *(Total of Lines 144 & 155)*	55,466,714	54,052,769
157	**5. CUSTOMER ACCOUNTS EXPENSES**		
158	Operation		
159	(901) Supervision	1,052,643	1,057,730
160	(902) Meter Reading Expenses	1,190,898	2,310,484
161	(903) Customer Records and Collection Expenses	13,611,067	14,604,947
162	(904) Uncollectible Accounts	(182,109)	321,027
163	(905) Miscellaneous Customer Accounts Expenses	49,348	39,116
164	TOTAL Customer Accounts Expenses *(Total of Lines 159 thru 163)*	15,721,847	18,333,304
165	**6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES**		
166	Operation		
167	(907) Supervision	751,810	919,850
168	(908) Customer Assistance Expenses	30,440,420	19,876,898
169	(909) Informational and Instructional Expenses	0	562
170	(910) Miscellaneous Customer Service and Informational Expenses	13,035	599
171	TOTAL Cust. Service and Informational Exp. *(Total of Lines 167 thru 170)*	31,205,265	20,797,909

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, 2013

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)
172	**7. SALES EXPENSE**		
173	Operation		
174	(911) Supervision	0	480
175	(912) Demonstrating and Selling Expenses	98,405	222,714
176	(913) Advertising Expenses	110	390
177	(916) Miscellaneous Sales Expenses		
178	Total Sales Expenses *(Total of Lines 174 thru 177)*	98,515	223,584
179	**8. ADMINISTRATIVE AND GENERAL EXPENSES**		
180	Operation		
181	(920) Administrative and General Salaries	34,425,872	26,678,857
182	(921) Office Supplies and Expenses	3,812,666	3,076,383
183	(Less) (922) Administrative Expenses Transferred - **CR**	4,182,032	4,966,861
184	(923) Outside Services Employed	7,380,988	24,930,210
185	(924) Property Insurance	4,470,216	4,407,050
186	(925) Injuries and Damages	5,770,830	6,444,620
187	(926) Employee Pensions and Benefits	33,617,416	37,817,551
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	11,759,489	13,085,376
190	(929) (Less) Duplicate Charges - **CR**.	575,335	370,156
191	(930.1) General Advertising Expenses	167,607	276,915
192	(930.2) Miscellaneous General Expenses	5,399,463	5,318,780
193	(931) Rents	7,053,777	6,755,425
194	TOTAL Operation *(Total of Lines 181 thru 193)*	109,100,957	123,454,150
195	Maintenance		
196	(935) Maintenance of General Plant	6,480,687	4,055,727
197	TOTAL Administrative and General Expenses *(Total of Lines 194 & 196)*	115,581,644	127,509,877
198	TOTAL Electric Operation and Maintenance Expenses *(Enter total*	1,696,785,977	1,621,401,967
199	*of lines 80, 112, 131, 156, 164, 171, 178, and 197)*		

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)	12/31/2013	12/31/2012
2. Total Regular Full-Time Employees	2,565	2,627
3. Total Part-Time and Temporary Employees	4	10
4. Total Employees	2,569	2,637

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Company	(2) [ ] A Resubmission		December 31, 2013

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	93	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	103	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	185	b	The insurance expenses for generation included in I&M's generation formula rate are identified by a query from the general ledger.

This Page Intentionally
Left Blank

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 2013/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 Classifi-cation (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	AEP Service Corporation	OS	17			
3	AEP Service Corporation	OS	20			
4	Ameren Energy Marketing	OS				
5	Associated Elect Cooperative	OS				
6	B.P. Energy Company	OS				
7	Beech Ridge Energy LLC	OS				
8	Buckeye Rural Electric Administration	OS				
9	CMS Marketing Svcs and Trading	OS				
10	DB Energy Trading LLC	OS				
11	Dynegy Power Marketing Inc.	OS				
12	EDF Trading North America LLC	OS				
13	Exelon Generation - Power Team	OS				
14	Fowler Ridge II Wind Farm LLC	OS				
	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)	
5,532,653			108,821,464	142,696,757		251,518,221	1
5,420,180			7,029,441	174,657,708		181,687,149	2
60				3,266		3,266	3
			5,214			5,214	4
110				3,938		3,938	5
				-141,275		-141,275	6
				-22,575		-22,575	7
				458,242		458,242	8
			82,760			82,760	9
				53,348		53,348	10
			9,423			9,423	11
			135,475			135,475	12
				83,271		83,271	13
134,981				10,951,866		10,951,866	14
13,772,690			140,733,707	477,502,307		618,236,014	

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 2013/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 Classifi-cation (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	Fowler Ridge Wind Farm LLC	OS				
2	French Paper	OS				
3	Ft. Wayne Electric JATC	OS				
4	J ARON & Company	OS				
5	JP Morgan Ventures Energy Corp	OS				
6	LG&E Utilities Power Sales	OS				
7	Midwest ISO	OS				
8	Mizuho Securities USA Inc	OS				
9	National Power Cooperative Inc	OS				
10	OVEC Power Scheduling	OS				
11	Over / Under Capacity Expenses Tracker	OS	17			
12	Over/Under PJM Exp Tracker	OS				
13	Paulding Wind Farm II, LLC	OS				
14	PJM Interconnection	OS				
	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)	
238,962				14,411,008		14,411,008	1
2,247				65,894		65,894	2
1				23		23	3
				432		432	4
			156,674			156,674	5
316				13,693		13,693	6
5,501				223,075		223,075	7
				14,749		14,749	8
9,367			69,795	1,163,858		1,233,653	9
781,963			27,103,580	25,126,826		52,230,406	10
			-3,292,705			-3,292,705	11
				27,922,643		27,922,643	12
				-236,953		-236,953	13
1,241,343			609,367	63,857,175		64,466,542	14
13,772,690			140,733,707	477,502,307		618,236,014	

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 2013/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 Classifi-cation (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	Randolph Schools	OS				
2	TVA Bulk Power Trading	OS				
3	UBS Securities LLC	OS				
4	Wildcat Wind farm	OS				
5	William E Richter	OS				
6	Wisconsin Electric Power Co	OS				
7	Wisconsin Power & Light	OS				
8	Adjustment	OS				
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)	
				38,349		38,349	1
113,459				2,668,344		2,668,344	2
				214,789		214,789	3
291,545				13,201,566		13,201,566	4
2				43		43	5
			130			130	6
			3,089			3,089	7
				72,247		72,247	8
							9
							10
							11
							12
							13
							14
13,772,690			140,733,707	477,502,307		618,236,014	

FOOTNOTE DATA

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

Affiliated Company

Schedule Page: 326 Line No.: 2 Column: a

Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company and Ohio Power Company are associated companies and were members of the American Electric Power System Power Pool, whose electric facilities are interconnected at a number of points and are operated in a fully coordinated manner on a system pool basis. Power transactions between the members of the AEP System Pool were governed by the terms of the interconnection agreement dated July 6, 1951, as amended, and are processed by American Electric Power Service Corporation. See Notes to Financial Statements for discussion of termination of interconnection agreement as of 12/31/2013.

Schedule Page: 326 Line No.: 3 Column: a

Affiliated Company - transactions related to the System Integration Agreement. See pages 122-123 (Notes to Financial Statements) Related Party Transactions - System Integration Agreement for additional information.

Schedule Page: 326.2 Line No.: 8 Column: a

Reclassification between 447 and 555 accounts to incorporate certain trading/marketing activity. The amounts represented on Page 310-11 and 326-27 are equal and off-setting.

This Page Intentionally
Left Blank

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 2013/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 Classification (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 Network Integ Rev - Affil	Various	Various	FNS
6	PJM Point to Point Trans Serv	Various	Various	LFP
7	PJM Trans Owner Admin Revenue	Various	Various	OLF
8	PJM Trans Owner Serv Rev Whlsle	Various	Various	OLF
9	PJM Expansion Cost Recovery	Various	Various	OS
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 2013/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	

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 2013/Q4

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
5,075,721			5,075,721	1
28,474,441			28,474,441	2
552,441			552,441	3
40,380			40,380	4
-680,690			-680,690	5
1,595,773			1,595,773	6
	380,474		380,474	7
	62,321		62,321	8
337,942			337,942	9
		134,194	134,194	10
		528,232	528,232	11
138,443			138,443	12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
35,534,451	**442,795**	**662,426**	**36,639,672**	

FOOTNOTE DATA

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 ILDSA AEP Tariff 3rd Revised Volume No. 6.

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

Per Proforma ILDSA (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)	December 31, 2013

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 if 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	Acct 454 - Rents from Electric Property - Michigan		
17	Miscellaneous Lessees	Pole Contact Rental	884,506
18	American Electric Power Service Corporation **	Benton Harbor Service Center	8,691
19	Miscellaneous Lessees	Agricultural, Commercial, & Residential	106,922
20			
21			
22	Total Acct 454		1,000,119
23			
24	Acct 455	None	
25			
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)	December 31, 2013

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 water 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			0

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	Acct 451 - Miscellaneous Service Revenues - Michigan	
12	Other	763,027
13		
14	Acct 456 - Other Electric Revenues - Michigan	
15		
16		
17	Associated Business Development	333,963
18		
19	Michigan Net Lost Revenue	1,550,534
20		
21	PJM/RTO Cost Recovery Items	6,501,615
22		
23		
24		
25		
26		
27		
28		
29		
30	TOTAL	9,149,139

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 2013/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		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	PJM Enhancements	OS					9,424,886	9,424,886
2	PJM NITS	OS					18,881,194	18,881,194
3	PJM-Trans Owner	OS					638,148	638,148
4	Other	OS					209	209
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						28,944,437	28,944,437

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

Transmission Enhancement Charges and Credits (PJM OATT Schedule 12)

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

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

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

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

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

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

Name of Respondent	This Report Is:	Date of Report	Year of Report
INDIANA MICHIGAN POWER COMPANY - MICHIGAN	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/2013

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)
GE Capital Commercial Inc (GE)	Office Furniture and Equipment and Transportation Equipment (2)	
Huntington Bank	Office Furniture and Equipment and Transportation Equipment (2)	
RBS Asset Finance	Office Furniture and Equipment and Transportation Equipment (2)	

Name of Respondent	This Report Is:	Date of Report	Year of Report
INDIANA MICHIGAN POWER COMPANY - MICHIGAN	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/2013

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 (d)	Expense to be Paid By Lessee Itemize (e)	Amount of Rent - Current Term, Current Year, Lessor (f)	Amount of Rent - Current Term, Current Year, Other (g)	Amount of Rent - Current Term, Lessor (h)	Amount of Rent - Current Term, Other (i)	Account Charged (j)	Remaining Annual Charges Under Lease Est. If Not Known (k)
		10,957				506	
		1,157				524	
		909				566	
		52,183				588	
		23,139				931	
		175				935	
		89,232				501	
		63,380				506	
		37,051				514	
		1,382,043				524	
		3,648				566	
		507				580	
		151,139				588	
		430,216				931	
		17,878				935	
		181,597				501	
		10,329				524	
		33,726				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)	Year of Report 12/31/2013

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.	
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.	

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/2013

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				Account Charged (j)	Remaining Annual Charges Under Lease Est. If Not Known (k)
		Current Year					
		Lessor (f)	Other (g)	Lessor (h)	Other (i)		
	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)	Year of Report 12/31/2013

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.	12/31/2014
Aetna Life Insurance Co. and One Summit Associates	Fort Wayne General Office Building- One Summit Square (1) Date of Lease: 10-25-78 BLDG227 Ls# 2059 LPM2688 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 is noncancellable 4. Respondent is responsible for all operation and maintenance expenses.	10/23/2013
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	
U.S. Bank Trust N.A.	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)	Year of Report 12/31/2013

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				Account Charged (j)	Remaining Annual Charges Under Lease Est. If Not Known (k)
		Current Year					
		Lessor (f)	Other (g)	Lessor (h)	Other (i)		
5,225,000	Real Estate taxes, assessments, maintenance, alterations, replacements and additions, insurance, and utilities.			1,183,277		567	
				1,808,390		588	
				2,517,082		589	
				111,802		921	
				698,760		184	
		537,500		7,605,705		931	671,875
44,668,660	Real Estate taxes, assessments, maintenance, alterations, replacements and additions, insurance, and utilities.			-22		506	
				1,801,102		566	
				4,829,851		567	
				4,561,517		588	
				2,450,128		589	
				6,325,888		921	
		5,042,487		77,730,822		931	14,287,044
				5,479,250		184	
	Maintenance, alterations, replacements, additions and insurance	64,140				931	
850,000,000	All expenses necessary to operate, maintain, preserve and keep the leased property in good working order. Also responsible for taxes and insurance.	73,853,988		1,775,851,582	26,654,952	507	59,722,589

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/2013

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	D.C. Cook Nuclear Plant Visitor's Center BLDG248, LPM1862 Date of Lease: 5-1-71 1. This is not 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.	
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.	
Green, B.G. & Teresa	New Buffalo Service Center BLDG247 Ls# 2058	
American Tower, LP	Milan Telecom Site	
Global Tower, LLC	Butler Telecom	
Capital Tower LLC	Lansing Office LPM9010	
	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.	

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/2013

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				Account Charged (j)	Remaining Annual Charges Under Lease Est. If Not Known (k)
		Current Year					
		Lessor (f)	Other (g)	Lessor (h)	Other (i)		
		83,920				931	
		90,000				931	
		39,287				931	
		38,425				935	
		43,853				935	
		50,946				931	
	Total Section A	82,493,914					

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/2013

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)
GE Capital Commercial Inc (GE)	Office Furniture and Equipment and Transportation Equipment (2)	
Huntington Bank	Office Furniture and Equipment and Transportation Equipment (2)	
RBS Operating Co	Transportation Equipment	
Renaissance Capital Alliance LLC	Transportation Equipment	
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)	12/15/2024
U.S. Bank Trust N.A.	Railcars Trust 94-1 (Lease 3708) Railcars Trust 91-5 (Lease 4490) - Renewal of 00736 Railcars Trust 91-3 (Lease 4461) - Renewal of 00735 Railcars Trust 91-2 (Lease 4462) - Renewal of 3702	12/30/2014 12/31/2016 9/30/2016 9/30/2016
Pitney Bowes	Water Transportation Equipment	10/1/2014
Wilmington Trust	Water Transportation Equipment	04/01/2015
State Street Bank	Water Transportation Equipment	07/01/2013
CIT Group/Equipment Financing, Inc.	Water Transportation Equipment (3) Date of Lease: 03/01/88, 02/01/89, 10/01/90, & 04/01/93 1. This is not a sale and leaseback. 2. Lessee has an option to purchase any or all of the vessels at the end of the original charter period or any extension thereof at a purchase price equal to the fair market value of the vessels at such date. 3. Lessee has option to terminate this lease subject to certain conditions. 4. Respondent is responsible for all operation and maintenance expenses.	01/01/2013 (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)	Year of Report 12/31/2013

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				Account Charged (j)	Remaining Annual Charges Under Lease Est. If Not Known (k)
		Current Year					
		Lessor (f)	Other (g)	Lessor (h)	Other (i)		
		50,527				107	
		736,220				152	
		2,244,014				184	
		910,001				417	
		155,333				107	
		71,917				152	
		276,330				163	
		7,384				184	
		20,689				107	
		58,473				152	
		6,000				163	
		1,473,395				184	
		69,964				417	
		1,197,886				184	
		1,386,237				186	35,125,251
		16,541				242	
12,271,945		1,841,392		15,470,219		186	28,367,144
8,220,826		1,120,983				186	1,123,888
18,966,753		967,450				186	2,952,736
4,379,951		247,552				186	691,920
17,637,125		1,003,590				186	2,771,023
36,397,500		3,410,025		50,688,429		417	
19,030,575		1,495,524		22,019,712		417	
12,656,244		379,335		7,575,414		417	
9,035,000	Taxes except federal & state income, assessments operation and maintenance expenses, altering, replacements and additions, insurance, etc.	178,453		49,366,339		417	

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/2013

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)
RBS Asset Refinance	Water Transportation Equipment	12/30/2022
RBS Asset Refinance	Water Transportation Equipment	01/24/2021
Mitchland LLC (formerly Rashid Bros)	Water Transportation Equipment	07/31/2018
Consolidation Coal Company	Water Transportation Equipment	08/31/2017
FM, LLC	Water Transportation Equipment	12/31/2016
RBS Asset Refinance	Water Transportation Equipment	08/31/2020
Chase Equipment Leasing	Water Transportation Equipment	01/29/2028
Chase Equipment Leasing	Water Transportation Equipment	06/04/2026
BB&T Finance	Water Transportation Equipment	06/29/2019
Chase Equipment Leasing	Water Transportation Equipment	09/24/2026
Regions Equipment Finance	Water Transportation Equipment	12/17/2019
Manufacturers and Traders Trust Co	Water Transportation Equipment	6/24/2029

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/2013

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)	Lessor (h)	Other (i)	Account Charged (j)	Remaining Annual Charges Under Lease Est. If Not Known (k)
		2,215,114					
		882,643					
		15,760					
		36,000					
		71,175					
		2,130,530					
		627,765					
		921,725					
		1,174,029					
		1,015,022					
		1,328,256					
		824,403					
	Total Section B	30,567,637					

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 2013/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	2,919,888
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	7,900
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	843,465
7	American Electric Power Service Corp Billings	466,843
8	Nuclear Plant Insurance	926,026
9	Corporate Money Pool Allocations	21,622
10	Misc Financing and Legal Expenses	135,457
11	Corporate Contributions and Memberships	309,038
12	Cafeteria Subsidy Expenses	10,501
13	Labor Accruals	19,594
14	River Transport Division Expenses	-40
15	Intercompany Billings	-231,894
16	Minor Items	-28,937
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	5,399,463

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 2013/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			15,281,406		15,281,406
2	Steam Production Plant	37,743,751	954,759	4,333,534		43,032,044
3	Nuclear Production Plant	38,026,586	8,636,512			46,663,098
4	Hydraulic Production Plant-Conventional	1,275,753	5,874			1,281,627
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	20,181,719				20,181,719
8	Distribution Plant	45,237,596				45,237,596
9	Regional Transmission and Market Operation					
10	General Plant	3,009,246	3,378	1,161,881		4,174,505
11	Common Plant-Electric					
12	TOTAL	145,474,651	9,600,523	20,776,821		175,851,995

B. Basis for Amortization Charges

Section A, Line 1, Column D represents amortization of franchises over the life of the franchise totaling $610,352 and amortization of capitalized software development cost over a 5 year life totaling $14,671,054.

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 2013/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	93,051		18.00	1.95		
14	311 - Rockport U2	4,045		2.00	2.96		
15	311 - Tanners Crk Plant	46,804		15.00	1.96		
16	311 - Tanners Precips	6,874		15.00	2.02		
17	312 - Rockport ACI	11,817		6.00	3.33		
18	312 - Rockport U1	420,348		18.00	2.10		
19	312 - Rockport U2	18,217		2.00	3.16		
20	312 - Tanners Crk Plant	364,925		15.00	4.28		
21	312 - Tanners Crk SNCR	14,152		15.00	15.71		
22	312 - Tanners Precips	76,225		15.00	2.10		
23	314 - Rockport U1	89,949		18.00	2.37		
24	314 - Rockport U2	776		2.00	3.30		
25	314 - Tanners Crk Plant	87,786		15.00	2.83		
26	315 - Rockport U1	57,913		18.00	1.94		
27	315 - Rockport U2	2,049		2.00	3.16		
28	315 - Tanners Crk Plant	19,415		15.00	3.15		
29	315 - Tanners Precips	7,888		15.00	2.04		
30	316 - Rockport U1	14,816		18.00	2.30		
31	316 - Rockport U2	6,783		2.00	2.92		
32	316 - Tanners Crk Plant	9,217		15.00	3.75		
33	316 - Tanners Precips	310		15.00	2.05		
34	TOTAL STEAM	1,353,360					
35							
36	NUCLEAR						
37	321 - Cook U1	77,169		1.00	1.00		
38	321 - Cook U2	280,466		1.00	1.29		
39	322 - Cook U1	541,063		1.00	1.84		
40	322 - Cook U2	667,915		2.00	1.71		
41	323 - Cook U1	242,132		2.00	2.48		
42	323 - Cook U2	198,004		2.00	1.62		
43	324 - Cook U1	93,138			1.28		
44	324 - Cook U2	100,142			1.48		
45	325 - Cook U1	28,339		-1.00	2.62		
46	325 - Cook U2	164,751		-1.00	1.85		
47	TOTAL NUCLEAR	2,393,119					
48							
49	HYDRO						
50	331 - Berrien Springs	525		25.00	3.03		

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 2013/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	331 - Buchanan	232		25.00	2.16		
13	331 - Constantine	272		25.00	3.07		
14	331 - Crew Service Cent	417		25.00	1.66		
15	331 - Elkhart	863		25.00	3.13		
16	331 - Mottville	497		25.00	2.71		
17	331 - Twin Branch	539		25.00	2.37		
18	332 - Berrien Springs	5,109		25.00	2.53		
19	332 - Buchanan	4,512		25.00	2.35		
20	332 - Constantine	1,004		25.00	2.74		
21	332 - Elkhart	4,067		25.00	2.84		
22	332 - Mottville	2,189		25.00	2.18		
23	332 - Twin Branch	3,329		25.00	1.91		
24	333 - Berrien Springs	7,139		25.00	3.15		
25	333 - Buchanan	1,292		25.00	2.42		
26	333 - Constantine	743		25.00	3.01		
27	333 - Elkhart	607		25.00	2.29		
28	333 - Mottville	568		25.00	2.45		
29	333 - Twin Branch	5,892		25.00	2.87		
30	334 - Berrien Springs	1,208		25.00	2.90		
31	334 - Buchanan	1,021		25.00	2.79		
32	334 - Constantine	378		25.00	3.90		
33	334 - Elkhart	451		25.00	2.56		
34	334 - Mottville	611		25.00	3.02		
35	334 - Twin Branch	1,623		25.00	2.73		
36	335 - Berrien Springs	790		25.00	3.27		
37	335 - Buchanan	265		25.00	3.22		
38	335 - Constantine	257		25.00	5.28		
39	335 - Crew Service Cent	127		25.00	1.62		
40	335 - Elkhart	184		25.00	4.86		
41	335 - Mottville	194		25.00	3.93		
42	335 - Twin Branch	408		25.00	3.39		
43	336 - Mottville	1		25.00	1.66		
44	TOTAL HYDRO	47,314					
45							
46	TRANSMISSION						
47	350 (Rights)	54,463	65.00		1.23	R5	
48	352	21,026	75.00	10.00	1.30	R4	
49	352 - City Lights Acq	31			5.26		
50	353	635,220	50.00	-10.00	1.68	R1	

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 2013/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	353 - City Lights Acq	294			5.37		
13	354	231,375	59.00	20.00	1.54	R5	
14	355	113,425	57.00	44.00	2.42	R1	
15	356	239,874	65.00	13.00	1.50	R3	
16	356 - City Lights Acq	7			5.27		
17	357	1,594	50.00		1.50	L5	
18	357 - City Lights Acq	733			5.33		
19	358	5,736	60.00	7.00	1.52	R3	
20	358 - City Lights Acq	327			5.31		
21	359	350	65.00		1.48	R5	
22	TOTAL TRANSMISSION	1,304,455					
23							
24	DISTRIBUTION						
25	360 (Rights)	12,593	65.00		1.44	R5	
26	361	9,528	70.00	12.00	1.49	R2	
27	361 - City Lights Acq	312					
28	362	188,776	50.00	1.00	1.95	L0	
29	362 - City Lights Acq	2,433					
30	363	5,489	15.00		6.48	SQ	
31	364	228,140	38.00	63.00	4.01	R0.5	
32	364 - City Lights Acq	547					
33	365	342,077	40.00	5.00	2.52	R0.5	
34	365 - City Lights Acq	495					
35	366	63,905	55.00		1.71	R2.5	
36	366 - City Lights Acq	2,218					
37	367	187,474	40.00		2.32	R2	
38	367 - City Lights Acq	1,342					
39	368	277,349	30.00	3.00	3.08	R1.5	
40	368 - City Lights Acq	67					
41	369	155,755	45.00	17.00	2.44	R0.5	
42	369 - City Lights Acq	2,396					
43	370	84,387	25.00	22.00	4.07	S5	
44	370.16	3,715			10.00		
45	371	23,366	16.00	20.00	6.84	L0	
46	371 - City Lights Acq	9					
47	373	19,029	25.00	7.00	3.68	R0.5	
48	TOTAL DISTRIBUTION	1,611,402					
49							
50	GENERAL PLANT						

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 2013/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	390	36,724	45.00	-14.00	1.93	S1.5	
13	391	5,556	22.00	-7.00	4.30	SQ	
14	393	43	14.00		7.21	SQ	
15	394	9,903	16.00		6.32	SQ	
16	395	303	20.00	-1.00	5.04	SQ	
17	396	545	25.00		4.03	SQ	
18	397	39,455	27.00	-14.00	3.24	SQ	
19	397.16	398	10.00		10.00		
20	398	8,130	30.00	-12.00	2.95	SQ	
21	TOTAL GENERAL PLANT	101,057					
22							
23	DEPRECIABLE SUM	6,810,707					
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

FOOTNOTE DATA

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

Generation Step-Up Units' (GSUs) 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.: 23 Column: b

The depreciable plant base is the November 30, 2013 total company depreciable plant.

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

This Page Intentionally
Left Blank

Name of Respondent	This Report Is:	Date of Report	Year of Report
INDIANA MICHIGAN POWER COMPANY - MICHIGAN	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 2013

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	TOTAL 425	
3		
4	426 OTHER INCOME DEDUCTIONS	
5		
6	426.1 DONATIONS	
7		
8	Community Chest	525,182
9	Service Organizations	749,552
10	AEP Service Corp Contributions	59,593
11	Schools, Colleges, and Universities	148,477
12	AEP Foundation	432,505
13	Other minor items	(150,542)
14		
15	Subtotal 426.1	1,764,767
16		
17	426.3 PENALTIES	
18	NERC Penalty with Reliability FIRST Corporation	(75,000)
19	Other minor items	48,473
20		
21		
22	Subtotal 426.3	(26,527)
23		
24	426.4 EXPENDITURES FOR CERTAIN CIVIC, POLITICAL, AND RELATED ACTIVITY	
25	AEP Service Corp Expenses	535,815
26	Labor Overheads	72,293
27	Nuclear Waste Strategy	10,690
28	Business & Meeting Expenses	264,098
29	Legislative & Lobbying Services	104,076
30	Nuclear Energy Institute	26,076
31	Other Minor Items	(29,145)
32		
33	Subtotal 426.4	983,903
34		
35	426.5 OTHER DEDUCTIONS	
36		0
37	Factored Customer Accounts Receivable Expense	6,535,071
38	Blackhawk Coal Shutdown Costs	38,162
39	Ripley Environmental Site	(56,884)
40	AEP Service Corp Expenses	106,960
41	Other minor items	187,864
42		
43	Subtotal 426.5	6,811,173
44		
45	TOTAL 426	9,533,316

Name of Respondent	This Report Is:	Date of Report	Year of Report
INDIANA MICHIGAN POWER COMPANY - MICHIGAN	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 2013

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		
2	Money Pool Interest	70,160
3		
4	TOTAL 430	70,160
5		
6	431 OTHER INTEREST EXPENSE	
7	Interest related to FIN-48 tax adjustments	197,660
8	Interest on Customer Deposits	1,651,933
9	Lines of Credit	2,103,521
10	Fuel Recovery	54,173
11	IPP Projects	92,456
12	Fort Wayne Settlement	1,154,495
13	Other minor items	(1,942)
14	Issuance Expenses	231,164
15		
16	TOTAL 431	5,483,460
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		

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, 2013

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	125,455
2	Misc items under 5% of total (3 items)	629
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16	**Total Acct 426.4**	**126,084**
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		

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, 2013

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			
3	NONE		
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			
22	NONE		
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 2013/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 Fees	2,409,220	30,246	2,439,466	
3	- Annual Fees	8,591,992		8,591,992	
4	- Licensing Fees	491,525		491,525	
5					
6					
7	Indiana Rate Case		-228,427	-228,427	
8	amortz 3/2013-2/2016				
9	per IURC Order #44075				
10					
11	Michigan Rate Case		92,046	92,046	115,058
12	amortz 4/2012-3/2014				
13	per MPSC Rate Case #U-16801				
14					
15	Misc Labor & Incentive accruals		2,935	2,935	
16					
17	Current Indiana Rate Case		86,059	86,059	
18					
19	Current Michigan Rate Case		94,055	94,055	
20					
21	FERC 205 Filing		32,004	32,004	
22					
23	Indiana Cook Life Cycle Management Program		87,616	87,616	
24					
25	Indiana IRP Filing		59,679	59,679	
26					
27	Minor Items < $25,000		10,539	10,539	
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	11,492,737	266,752	11,759,489	115,058

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 2013/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
	928	2,439,466					2
	928	8,591,992					3
	928	491,525					4
							5
							6
	928	-487,376	932,217	928	258,949	673,268	7
							8
							9
							10
				928	92,046	23,012	11
							12
							13
							14
	928	2,935					15
							16
	928	86,059					17
							18
	928	94,055					19
							20
	928	32,004					21
							22
	928	87,616					23
							24
	928	59,679					25
							26
	928	10,539					27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		11,408,494	932,217		350,995	696,280	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 2013/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	5 items < $50,000
2		1 item <$50,000
3		Generation Asset Management - Program Management
4	A(1)e: Generation: Unconventional	2 items <$50,000
5		2 items <$50,000
6	A(2): Transmission	4 items <$50,000
7	A(2)a: Transmission: Overhead	1 item <$50,000
8	A(3): Distribution	2 items <$50,000
9	A(5): Environment (other than equipment)	Industrial Advisory Committee - Southern Company
10		3 items <$50,000
11	A(6): Other	2 items <$50,000
12		2 items <$50,000
13		3 items <$50,000
14		6 items <$50,000
15	A(6)f: Other: Metering	1 item <$50,000
16	A(6)g: Research-General	1 item <$50,000
17		1 item <$50,000
18		1 item <$50,000
19		1 item <$50,000
20	A(7) TOTAL COSTS INCURRED INTERNALLY	
21		
22	B(1): Research Support to Electric Research	EPRI Environmental Science
23		EPRI Research Portfolio
24		EPRI Research Portfolio
25		EPRI Research Portfolio
26		EPRI Environmental Controls
27		EPRI Nuclear Annual Research
28		EPRI In-Situ Stabilization of MGP Sediment
29		EPRI Full Scale Demo of SAP for Mercury Control
30		49 items <$50,000
31		1 item <$50,000
32		25 items <$50,000
33		10 items <$50,000
34	B(4): Research Support to Others	3 items <$50,000
35		2 items <$50,000
36		
37	B(5) TOTAL COSTS INCURRED EXTERNALLY	
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
54,727		506	54,727		1
2,929		524	2,929		2
53,792		506	53,792		3
11,530		506	11,530		4
4,068		588	4,068		5
13,229		566	13,229		6
29		566	29		7
3,237		588	3,237		8
525,003		506	525,003		9
8,067		506	8,067		10
4,431		506	4,431		11
8,248		524	8,248		12
9,187		566	9,187		13
26,617		588	26,617		14
12		588	12		15
903		506	903		16
5,260		524	5,260		17
450		566	450		18
2,619		588	2,619		19
734,338			734,338		20
					21
	1,342,718	506	1,342,718		22
	640,928	506	640,928		23
	223,681	566	223,681		24
	82,887	588	82,887		25
	339,501	506	339,501		26
	2,873,837	524	2,873,837		27
	56,000	506	56,000		28
	97,462	506	97,462		29
	269,541	506	269,541		30
	973	524	973		31
	46,865	566	46,865		32
	67,125	588	67,125		33
	21,408	566	21,408		34
	62,277	588	62,777		35
					36
	6,125,203		6,125,703		37

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 2013/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	82,395,306		
4	Transmission	983,709		
5	Regional Market			
6	Distribution	8,335,938		
7	Customer Accounts	3,469,063		
8	Customer Service and Informational	2,092,332		
9	Sales			
10	Administrative and General	2,576,201		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	99,852,549		
12	Maintenance			
13	Production	55,065,133		
14	Transmission	2,978,270		
15	Regional Market			
16	Distribution	10,595,876		
17	Administrative and General	1,426,508		
18	TOTAL Maintenance (Total of lines 13 thru 17)	70,065,787		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	137,460,439		
21	Transmission (Enter Total of lines 4 and 14)	3,961,979		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	18,931,814		
24	Customer Accounts (Transcribe from line 7)	3,469,063		
25	Customer Service and Informational (Transcribe from line 8)	2,092,332		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	4,002,709		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	169,918,336	7,912,143	177,830,479
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

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)	169,918,336	7,912,143	177,830,479
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	39,033,964	1,817,592	40,851,556
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	39,033,964	1,817,592	40,851,556
72	Plant Removal (By Utility Departments)			
73	Electric Plant	8,039,367	374,348	8,413,715
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	8,039,367	374,348	8,413,715
77	Other Accounts (Specify, provide details in footnote):			
78	120 - Nuclr Fuel in Proc of Refinmnt	250,566		250,566
79	124 - Other Assets	1,949		1,949
80	152 - Fuel Stock Undistributed	5,586,695		5,586,695
81	163 - Stores Expense Undistributed	7,831,108	-7,831,108	
82	165 - Other Prepayments	-92,637		-92,637
83	183 - Prelim Survey	22,077	-22,077	
84	184 - Clearing Accounts	2,250,898	-2,250,898	
85	185 - ODD Temporary Facilities	55,490		55,490
86	186 - Misc Deferred Debits	389,112		389,112
87	188 - Research & Development	-547		-547
88	228 - RAD Waste Accrual	3,573		3,573
89	242 - Misc Current & Accrued Liab	-70,138		-70,138
90	417 - Misc Expense	20,752,999		20,752,999
91	426 - Political Activities	85,341		85,341
92				
93				
94				
95	TOTAL Other Accounts	37,066,486	-10,104,083	26,962,403
96	TOTAL SALARIES AND WAGES	254,058,153		254,058,153

FOOTNOTE DATA

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

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

Name of Respondent 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, 2013

COMMON UTILITY PLANT AND EXPENSES

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

NONE

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, 2013

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 $50,000, 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	30,542,554
	Retirement Work in Progress		108	526,557
	Nuclr Fuel in Proc of Refinmnt		120	42,201
	Nonutility Property		121	15,491
	Other Investments		124	20,724
	Fuel Stock		151	(95)
	Fuel Stock Undistributed		152	2,409,925
	Clearing Accounts		163	2,035,397
	Preliminary Survey & Investig. Charges		183	401,815
	Clearing Accounts		184	(19)
	Misc Deferred Debits		186	338,458
	Deferred Debits-R&D		188	3,112,954
	Current & Accrued Liabilities		242	4,137
	Depreciation		403	822
	Non-Utility Operations Revenue		417	1,131,080
	Non-Operating Rental Income		418	1,009
	Misc Non-Operating Revenues		421	28,627
	Other Income Deductions		426	720,758
Electric	Account 401	Operating Expense	500	5,171,816
			501	212,304
			502	380,022
			505	22
			506	222,352
			517	123,791
			524	1,345,690
			535	454,210
			537	1,860
			539	578,037
			546	47,435
			547	199
			548	0
			549	6,463
			555	140,908
			556	1,500,262
			557	3,481,428
			560	2,534,123
			561	1,853,388

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, 2013	
Electric	Account 401	Operating Expense (contd.)	562	1,678
			563	13,254
			566	974,048
			567	-
			580	1,239,788
			581	9,357
			582	4,527
			583	(4)
			584	18,196
			586	312,630
			588	1,315,479
			598	31
			901	89,828
			902	156,588
			903	8,895,478
			904	-
			905	36,432
			907	214,783
			908	96,489
			909	-
			910	13,035
			912	85,161
			920	29,958,261
			921	2,221,381
			922	0
			923	2,918,801
			924	610
			925	36,058
			926	74,111
			928	204,849
			930	677,941
			931	266,285
Electric	Account 401	Total Operating Expense		67,889,385
Electric	Account 402	Maintenance Expense	510	587,109
			511	34,061
			512	905,193
			513	1,363,472
			514	85,923
			528	344,190
			530	2,023,285
			531	5,110
			532	56,296
			541	6,188
			542	89,043
			543	36,071
			544	31,576
			545	3,678
			553	2
			568	59,343
			569	851,681
			570	310,887
			571	269,419
			573	46,694
			575	0
			590	7,392
			591	7,778
			592	65,355
			593	115,837
			594	74
			595	(30)
			597	2,848
			935	2,695,416
Electric	Account 402	Total Maintenance Expense		10,003,891
		Total O&M		77,893,276
		Total AEP Service Corp charges		$ 119,225,672

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, 2013

Charges for Outside Professional & Other Consulting Services - Payments of $50,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
A P SERVICES LLC 203 ARMSTRONG DRIVE FREEPORT, PA 16229	sealing products and services	Invoice Cost	512	70,464
ABB INC 5480 CLOVERLEAF PARKWAY #1 CLEVELAND, OH 44125	system software development	Invoice Cost	107, 513	383,504
ADM ASSOCIATES INC 3239 RAMOS CIRCLE SACRAMENTO, CA 95827	environmental consulting services	Invoice Cost	908	327,428
ADVANCED ENERGY SOLUTIONS LLC 2401 LANCE LANE ROWLETT, TX 75088	energy technology services	Invoice Cost	107, 108	336,444
ADVANCED INDUSTRIAL MACHINING 30 DILLMONT DRIVE #286 WORTHINGTON, OH 43235	nuclear plant equipment rental	Invoice Cost	107, 108	92,641
AERIAL SOLUTIONS INC 7074 RAMSEY FORD ROAD TABOR CITY, NC 28463	tree trimming services	Invoice Cost	571	311,001
AEROTEK INC 7301 PARKWAY DRIVE HANOVER, MD 21076	equipment & maintenance services	Invoice Cost	107, 108, 186, 580, 588 590, 593	52,002
ALL CITIES OCCUPATIONAL & ENV 3333 S. STATE STREET SAINT JOSEPH, MI 49085	nuclear plant support staffing	Invoice Cost	524	57,632
ALSTOM POWER INC 2800 WATERFORD LAKE DR MIDLOTHIAN, VA 23112	inspection & measurement services	Invoice Cost	107, 108, 513, 532	673,024
AMERICAN SERVICE GROUP INC 105 WESTPARK DRIVE, SUITE 200 BRENTWOOD, TN 37027	facility maintenance services	Invoice Cost	512	50,144
APPLIED INSPECTION SYSTEMS INC 1418 AIRLANE DRIVE BENTON, AR 72015-4935	emissions testing	Invoice Cost	512	63,747
ARCADIA GARDENS LLC P.O. BOX 88 STEVENSVILLE, MI 49127	tree trimming services	Invoice Cost	107, 108, 529	61,235
AREA WIDE PROTECTIVE 826 OVERHOLT ROAD KENT, OH 44240	traffic control services	Invoice Cost	107, 108, 186, 571, 583 588, 593, 594, 596, 598	1,044,977
ARNT ASPHALT SEALING INC 1240 S. CRYSTAL AVENUE BENTON HARBOR, MI 49022	asphalt maintenance	Invoice Cost	107, 108, 186, 529	540,800
ASPLUNDH CONSTRUCTION CORP 950 TAYLOR STATION ROAD. COLUMBUS, OH 43230	construction contracting services	Invoice Cost	107, 185, 186, 583, 588 593, 594, 596, 930	14,743,951
ASPLUNDH TREE EXPERT 950 TAYLOR STATION ROAD. COLUMBUS, OH 43230	tree trimming services	Invoice Cost	107, 186, 593	21,397,423
ATC ENGINEERING SERVICES OF OHIO 11121 CANAL ROAD CINCINNATI, OH 45241	fly ash landfill engineering services	Invoice Cost	107	824,794

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, 2013

Charges for Outside Professional & Other Consulting Services - Payments of $50,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
BABCOCK & WILCOX PWR GEN INC 20 S. VAN BUREN DRIVE BARBERTON, OH 44203	plant equipment repair services	Invoice Cost	183	201,987
BAKER HUGHES PIPELINE MANAGEMENT 2301 OIL CENTER COURT HOUSTON, TX 77073	process and pipeline services	Invoice Cost	107	472,285
BARTLETT NUCLEAR INC 7633 EAST 63RD PLACE #400 TULSA, OK 74133	nuclear engineering services	Invoice Cost	530	92,941
BOSE PUBLIC AFFAIRS 1600 FIRST INDIANA PLAZA INDIANAPOLIS, IN 46204	legislative services	Invoice Cost	426, 921	62,076
BOWEN ENGINEERING CORPORATION 8802 NORTH MERIDIAN STREET INDIANAPOLIS, IN 46260	construction services	Invoice Cost	107	3,158,811
BROWN CONSULTING SERVICES LLC P.O. BOX 64 WHEELERSBURG, OH 45694	environmental consulting services	Invoice Cost	107	93,692
BROWN SERVICES CO LLC P.O. BOX 64 WHEELERSBURG, OH 45694	occupational safety services	Invoice Cost	107, 108	410,258
CARBON STEEL INSPECTION INC. 755 WILLIAM PITT WAY PITTSBURGH, PA 15238	advanced inspection services	Invoice Cost	512	76,250
CFM/VR TESCO INC 1875 FOX LANE ELGIN, IL 60123	valve repairs	Invoice Cost	512, 513	745,284
CLEARESULT CONSULTING INC 4301 WESTBANK DRIVE AUSTIN, TX 78746	energy management services	Invoice Cost	908	248,959
CMI SERVICES INC 18 EAST JEFFERSON STREET FRANKLIN, IN 46131	engineering & management services	Invoice Cost	107, 108, 586	636,657
COMMONWEALTH ASSOCIATES INC 2700 W ARGYLE JACKSON, MI 49204	electrical engineering & design services	Invoice Cost	107, 108	211,320
CONTXT CORPORATION 28276 KENSINGTON LANE PERRYSBURG, OH 43551	strategic planning services	Invoice Cost	921, 923	82,795
CRANE NUCLEAR INC 2825 COBB INTERNATIONAL BLVD. KENNESAW, GA 30152	valve solution services	Invoice Cost	107, 108, 530	811,631
CULY CONSTRUCTION & EXCAVATING 5 INDUSTRIAL PARK DRIVE WINCHESTERM IN 47394	drainage construction services	Invoice Cost	107, 108, 186, 570, 571 592	2,550,670
CUMMINS CROSSPOINT LLC 3621 WEST MORRIS STREET INDIANAPOLIS, IN 46241	product services	Invoice Cost	107	107,701
DAVEY RESOURCE GROUP 3728 FISHCREEK ROAD STOW, OH 44224	tree trimming services	Invoice Cost	107, 571	181,382

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, 2013

Charges for Outside Professional & Other Consulting Services - Payments of $50,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
DAVIS H ELLIOT COMPANY INC 673 BLUE SKY PARKWAY LEXINGTON, KY 40509	storm response services	Invoice Cost	186	1,387,016
DAY & ZIMMERMAN NPS INC 1827 FREEDOM RD LANCASTER, PA 17601	nuclear engineering support	Invoice Cost	107, 108, 163, 228, 520 524, 529, 530, 531, 532	30,693,750
DISCOVER READY LLC 1 EXCHANGE PLAZA FLOOR 6 NEW YORK, NY 10006	business consulting services	Invoice Cost	524, 923	363,849
DRIVECAM INC 8911 BALBOA AVENUE SAN DIEGO, CA 92123	fleet fuel management services	Invoice Cost	107, 588	65,528
DUDECK ROOFING & SHEET METAL 1634 FRANKLIN STREET SOUTH BEND, IN 46613	roofing services	Invoice Cost	107, 108, 542	350,163
E & T TREE SERVICE 125 MT AUBURN ST DUNKIRK, IN 47336	landscaping & tree removal services	Invoice Cost	107, 186, 584, 596	64,014
EASI LLC 1551 EAST LINCOLN AVENUE #105 MADISON HEIGHTS, MI 48071	employment services	Invoice Cost	107, 108, 186, 560, 570 571	1,547,792
EDISON ELECTRIC INSTITUTE 605 MELROSE STREET ALEXANDRIA, VA 22302	trade organization fees	Invoice Cost	506, 921	78,174
EDKO LLC 908 S. 11TH STREET BROKEN ARROW, OK 74012	perimeter security services	Invoice Cost	107, 571, 593	1,873,752
ELECTRICAL CONSULTANTS INC 3521 GABEL ROAD BILLINGS, MT 59102	planning services	Invoice Cost	107	483,705
ELEET CRYOGENICS INC 11132 INDUSTRIAL PARKWAY NW BOLIVAR, OH 44612	tank repair services	Invoice Cost	513	104,716
ENERFAB INC 4955 SPRING GROVE CINCINNATI, OH 45232	fabrication & Installation services	Invoice Cost	107, 108, 935	117,428
ENERGY GROUP INC 2704 EASTON BLVD. DES MOINES, IA 50317	utility employment services	Invoice Cost	186	305,850
ENGART AMERICA INC 150 STANAFORD RD BECKLEY, WV 25802	plant equipment maintenance	Invoice Cost	512	101,749
ENGINEERING VISION INC 5812 INDUSTRIAL ROAD FORT WAYNE, IN 46825	engineering & surveying services	Invoice Cost	107, 571	137,628
ENVIRONMENTAL REMEDIATION SVCS. 4010 OPTION PASS FT WAYNE, IN 46818	emergency cleanup services	Invoice Cost	186, 580	80,500
EVAP TECH INC 8331 NIEMAN ROAD LENEXA, KS 66214	cooling tower services	Invoice Cost	107, 513	2,699,988

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, 2013

Charges for Outside Professional & Other Consulting Services - Payments of $50,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
EXPONENT INC 1800 DIAGONAL ROAD #500 ALEXANDRIA, VA 22314	engineering services	Invoice Cost	524	344,795
FERGUSON ADVERTISING 803 S CALHOUN STREET #600 FORT WAYNE, IN 46802	marketing services	Invoice Cost	908	148,737
FLOWSERVE CORP 200 E MOMUMENT AVENUE DAYTON, OH 45402	employment services	Invoice Cost	530	66,028
FLSMIDTH AIRTECH INC 13100 EAST 101ST STREET NORTH OWASSO, OK 74055	material handling system project	Invoice Cost	107	1,819,556
FOERTSCH CONSTRUCTION COMPANY 12724 N STATE ROAD 245 LAMAR, IN 47550	site excavation services	Invoice Cost	107, 108, 542	136,461
FORT WAYNE ROOFING & SHEET METAL 4320 ARDMORE AVENUE FORT WAYNE, IN 46802	roofing services	Invoice Cost	107, 108, 542	1,341,968
G & L CORPORATION 3101 BROOKLYN AVE FORT WAYNE, IN 46809	equipment moving services	Invoice Cost	107, 108, 186, 570, 592	565,313
G4S SECURE SOLUTIONS (USA) INC 4200 WACKENHUT DR PALM BEACH GARDENS, FL 33410	security services	Invoice Cost	184, 501, 506	548,359
GAI CONSULTANTS INC 545 METRO PLACE SOUTH DUBLIN, OH 43017	engineering services	Invoice Cost	107	246,644
GAYLOR INC 5750 CASTLE CREEK PKWY N DRIVE INDIANAPOLIS, IN 46250	electrical contracting services	Invoice Cost	107, 108	1,244,050
GENEREX INC 3403 E WASHINGTON BLVD. FORT WAYNE, IN 46803	mechanical contracting services	Invoice Cost	107, 570, 591, 592, 935	84,241
GOOD CENTS 10350 BLUEGRASS PARKWAY LOUISVILLE, KY 40299	marketing & technology solutions	Invoice Cost	908	12,937,522
GRL ENGINEERS INC 30725 AURORA ROAD SOLON, OH 44139	testing and consulting services	Invoice Cost	107	108,852
GUS COMMERCIAL DIVERS LLC 12839 INDUSTRIAL PARK DRIVE GRANGER, IN 46530	marine inspection services	Invoice Cost	107, 543, 545	109,333
H C NUTTING 611 LUNKEN PARK DR CINCINNATI, OH 45226	concrete testing services	Invoice Cost	107	132,749
HAMON CUSTODIS INC 58 EAST MAIN STREET SOMERVILLE, NJ 08876	chimney construction services	Invoice Cost	107	302,819
HAVERFIELD INTERNATIONAL INC 1750 EMMITSBURG ROAD GETTYBURG, PA 17325	aerial inventory inspections	Invoice Cost	571	195,038

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, 2013

Charges for Outside Professional & Other Consulting Services - Payments of $50,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
HELICOPTER MINIT-MEN INC 3136 TRABUE ROAD COLUMBUS, OH 43204	helicopter services	Invoice Cost	571	302,127
HELICOPTERS SOUTHWEST 2 COLONIAL DRIVE TAXARKANA, AR 71854	helicopter services	Invoice Cost	571	53,786
HONEYWELL INTERNATIONAL INC 101 COLUMBIA ROAD MORRISTOWN, NJ 07962	industrial & security system supplies	Invoice Cost	908	1,309,098
HOOSIER HELICOPTER SERVICES 7900 N. THAMES DRIVE BLOOMINGTON, IN 47408	helicopter services	Invoice Cost	563, 571	102,828
HOUSTON, R & SON SANDBLASTING 115 MAY DRIVE HARRISON, OH 45030	sandblasting equipment services	Invoice Cost	107, 108, 512, 513, 530 531	64,357
HOWARD INDUSTRIES INC 1840 PROGRESS AVENUE COLUMBUS, OH 43215	power product services	Invoice Cost	107	160,000
IDEAL CONSOLIDATED INC 806 W SAMPLE STREET SOUTH BEND, ON 46601	plumbing and piping services	Invoice Cost	107, 542	52,456
IMPERIAL CRANE SERVICES INC 9735 INDUSTRIAL DRIVE BRIDGEVIEW, IL 60455	crane repair services	Invoice Cost	108	63,970
INDUSTRIAL CONTRACTORS INC 1001 BUCHANAN ROAD EVANSVILLE, IN 47720	equipment repairs	Invoice Cost	107, 108, 152, 186, 502 506, 511, 512, 513, 514	33,228,126
INSERV INC 1604 RUPEL ST SOUTH BEND, IN 46628	building maintenance services	Invoice Cost	108, 186, 571, 584, 588 593	89,785
JJ WHITE INC 5500 BINGHAM STREET PHILADELPHIA, PA 19120	construction services	Invoice Cost	529	72,936
JACO ENVIRONMENTAL INC various US locations	recycling services	Invoice Cost	908	533,970
KEITH FIRE EXTINGUISHER SERVICE 601 S HIGH ST RISING SUN, IN 47040	fire extinguisher inspection	Invoice Cost	107, 514	81,890
KEMA SERVICES INC P O BOX 1043 INDIANAPOLIS, IN 46071	office building repairs	Invoice Cost	908	1,690,826
KENRICH GROUP LLC 1250 CONNECTICUT AVE NW WASHINGTON, DC 20036	legal services (liability claims)	Invoice Cost	923	111,847
KENT POWER INC 90 SPRING STREET KENT CITY, MI 49330	power line relocation	Invoice Cost	107, 108, 544, 571	1,570,334
LANDSCAPE SOLUTIONS GROUP INC 52041 PATRICIA LANE SOUTH BEND, IN 46628	landscaping services	Invoice Cost	107, 186, 542, 562, 563 588, 594, 596	112,729
LE MYERS COMPANY 2415 W THOMPSON ROAD INDIANAPOLIS, IN 46217	electrical contracting services	Invoice Cost	107, 108, 186, 571	1,614,711

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, 2013

Charges for Outside Professional & Other Consulting Services - Payments of $50,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
LOCKHEED MARTIN UTILITY SERVICES INC various US locations	engineering services	Invoice Cost	908	1,992,107
MANPOWER various US locations	temporary staffing services	Invoice Cost	107, 108, 580, 583, 584 595	70,010
MASTER-LEE ENERGY SERVICES 5631 ROUTE 981 LATROBE, PA 15650	tooling services	Invoice Cost	107, 108	214,228
MCCARTHY, SEAN 1100 STEWART AVENUE GARDEN CITY, NY 11530	training services	Invoice Cost	930	58,204
MCGUIRES PROFESSIONAL CONSTRUCTION 335 URBANDALE AVENUE BENTONHARBOR, MI 49022	construction services	Invoice Cost	107, 524, 529	82,611
MEAD & WHITE ELECTRIC INC 9895 RED ARROW HIGHWAY BRIDGMAN, MI 49106	electrical construction services	Invoice Cost	542, 543	51,011
METRO ELEVATOR COMPANY INC 210 CARTER DRIVE WEST CHESTER, PA 19382	elevator maintenance services	Invoice Cost	107	109,100
MICHIANA LAND SERVICES INC 505 PLEASANT ST ST JOSEPH, MI 49085	land right of way services	Invoice Cost	107, 186, 563, 571	896,619
MICHIGAN COMMUNITY ACTION AGENCY 2173 COMMONS PARKWAY OKEMOS, MI 48864	energy optimization project	Invoice Cost	908	4,611,002
MILLER CONSTRUCTION CO. 225 THOMPSON ROAD ANDERSON, SC 29624	site preparation services	Invoice Cost	107, 108, 513	51,526
MISTRAS GROUP INC 600 KAISER DRIVE HEATH, OH 43056	asset protection services	Invoice Cost	107	160,227
MOFFITT REHAB SERVICES INC 200 PARK ROAD HAWESVILLE, KY 42348	excavation & site preparation	Invoice Cost	501	984,927
MOODY'S INVESTMENT SERVICE various US locations	business consulting services	Invoice Cost	923	123,561
MPW ENVIRONMENTAL SERVICES 9711 LANCASTER RD SE HEBRON, OH 43025	plant equipment maintenance & cleaning	Invoice Cost	107, 108, 152, 501, 510 511, 512, 513	888,770
MSA SYSTEMS INTEGRATION INC 1 INDUSTRIAL WAY WEST EATONTOWN, NJ 07724	system integration services	Invoice Cost	107	56,147
NELSON TREE SERVICE INC 3300 OFFICE PARK DRIVE DAYTON, OH 45439	tree trimming services	Invoice Cost	107, 571	2,552,984
NESCO SALES & RENTALS 4121 SOLUTIONS CENTER CHICAGO, IL 60677	plant equipment maintenance	Invoice Cost	107, 108, 186, 563, 566 571	210,383
NEUDORFER INCORPORATED 113 WOOD PARK DRIVE PITTSBURGH, PA 15209	air conditioning services	Invoice Cost	107	52,217

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, 2013

Charges for Outside Professional & Other Consulting Services - Payments of $50,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
NEW RIVER ELECTRICAL CORP 15 CLOVERDALE PLACE CLOVERDALE, VA 24077	storm restoration services	Invoice Cost	107, 108, 186, 570	1,094,994
NEWKIRK ELECTRIC ASSOCIATES 1875 ROBERTS STREET MUSKEGON, MI 49442	electrical construction services	Invoice Cost	107, 108, 186, 570, 571 930	3,794,103
NEWPORT NEWS INDUSTRIAL CORP 182 ENTERPRISE DRIVE NEWPORT NEWS, VA 23603	technical services	Invoice Cost	532	51,974
NG GILBERT 2905 ENTERPRISE DRIVE ANDERSON, IN 46013	construction project services	Invoice Cost	186	155,686
NURSING CORPS 500 LURAY DRIVE WINTERSVILLE, OH 43953	industry medical services	Invoice Cost	107	137,709
OPOWER INC 1515 N COURTHOUSE RD ARLINGTON, VA 22201	industrial supply services	Invoice Cost	908	427,611
OSMOSE UTILITIES SERVICES INC 215 GREENCASTLE ROAD TYRONE, GA 30290	pole maintenance services	Invoice Cost	186	363,919
PAR ELECTRICAL CONTRACTORS INC 4770 N BELLEVIEW AVENUE KANSAS CITY, MO 64116	emergency response services	Invoice Cost	107, 108	3,627,805
PARKLINE INC 4224 SCOTTSDALE ROAD ST JOESEPH, MI 49085	prefabricated metal building	Invoice Cost	107, 570	62,212
PARKS DRILLING CO 5745 AVERY ROAD DUBLIN, OH 43016	drilling services	Invoice Cost	107	135,071
PCI GLOBAL INSULATION 4450 BELDON VILLAGE STREET NW #106 CANTON, OH 44718	insulation supply services	Invoice Cost	107, 108, 530, 532	1,457,272
PEARSON CONSTRUCTION CO INC 240 W BRITAIN AVENUE BENTON HARBOR, MI 49023	general contracting services	Invoice Cost	107	152,532
PENN TOOLS SALES 625 BEV ROAD YOUNGSTOWN, OH 44512	tool repairs and rentals	Invoice Cost	107, 108, 530, 532	79,954
PIKE ELECTRIC INC 100 PIKE WAY MOUNT AIRY, NC 27030	engineering services	Invoice Cost	186	234,506
POOLED EQUIPMENT INVENTORY CO 3988 LORNA ROAD BIRMINGHAM. AL 35202	electrical equipment sales	Invoice Cost	163	84,882
POWER ENGINEERS 3940 GLENBROOK DRIVE HAILEY, ID 83333	engineering consulting services	Invoice Cost	107	242,201
PRECISION SERVICES INC 7090 HOWARD STREET SPARTANBURG, SC 29303	construction consulting services	Invoice Cost	512, 513	143,803

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, 2013

Charges for Outside Professional & Other Consulting Services - Payments of $50,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
PROFESSIONAL CONSTRUCTION SERVICES P.O. BOX 4697 STAMFORD, CT 06907	construction management services	Invoice Cost	107	96,998
PULVERIZER SERVICES, INC 200 PARK LOOP CALHOUN, KY 42327	plant equipment rebuilding services	Invoice Cost	107, 108, 512	246,219
RELIABLE TURBINE SERVICES INC 1502 GAULT ROAD HOUSTON, TX 77039	steam & gas turbine services	Invoice Cost	107, 513	61,275
REMA TIP TOP NORTH AMERICA INC 119 ROCKLAND AVENUE NORTHVALE, NJ 07647	chemical & allied product services	Invoice Cost	107, 108, 512	95,840
RILEY POWER INC 5 NEPONSET STREET WORCESTER, MA 01606	electrical services	Invoice Cost	107	267,252
ROBERT HENRY CORPORATION 404 SOUTH FRANCES STREET SOUTH BEND, IN 46624	construction services	Invoice Cost	107, 186, 594	1,116,225
SAFE POWER PARTNERS LLC 1052 GREENWOOD SPRING BLVD. GREENWOOD, IN 46143	plant safety services	Invoice Cost	152, 426, 501, 506	1,101,786
SAFWAY SERVICES LLC 3200 SHEFFIELD AVE HAMMOND, IN 46327	equipment rental	Invoice Cost	107, 108, 530, 531, 532	133,731
SARGENT & LUNDY LLC 55 E MONROE ST CHICAGO, IL 60603	nuclear engineering services	Invoice Cost	107, 923	128,557
SCEPTRE MECHANICAL INC 93 E COUNTY ROAD 200 N ROCKPORT, IN 47635	industrial supply services	Invoice Cost	152, 501, 506	98,046
SCHINDLER ELEVATOR CORP 20 WHIPPANY ROAD MORRISTOWN, NJ 07960	elevator services	Invoice Cost	526	96,411
SCHNEIDER CORPORATION 8901 OTIS AVENUE INDIANAPOLIS, IN 46216	engineering services	Invoice Cost	186	62,231
SCHWEITZER ENGINEERING LABORATORY 2350 NE HOPKINS COURT PULLMAN, WA 99163	engineering services	Invoice Cost	107	188,209
SCIENTECH various US locations	software support & licensing services	Invoice Cost	107, 108	59,958
SOUTHERN ELECTRIC CORPORATION 818 GREENVILLE AVENUE STAUNTON, VA 24401	electric utilities services	Invoice Cost	186	358,707
SSOE INC 100 EAST CAMPUS VIEW BLVD, STE. 340 COLUMBUS, OH 43235	engineering services	Invoice Cost	107, 108, 500	147,784
STAR FIELD FIT INC 116 LATOURETTE STREET MARION, OH 43302	turbine performance services	Invoice Cost	107, 108, 530	59,054
STERLETT CONSTRUCTION CO 34 BOOTH FIELD ROAD OWENSBORO, KY 42301	steel erection services	Invoice Cost	506, 512	54,579

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, 2013

Charges for Outside Professional & Other Consulting Services - Payments of $50,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
STERLING BOILER 1420 KIMBER LANE EVANSVILLE, IN 47715	electrical engineering services	Invoice Cost	107, 108, 512	699,729
SUMMIT ENVIRONMENT SERVICES P.O. BOX 263 BELMONT, WV 26134	power generation services	Invoice Cost	107, 108, 506, 511, 513	230,184
SUN TECHNICAL SERVICES INC 6490 S MCCARRAN BLVD RENO, NV 89509	engineering services	Invoice Cost	107, 108, 163, 165, 183 186, 500, 501, 506, 512 517, 524, 529-532, 566	1,453,704
SURVEYING AND MAPPING INC 4801 SOUTHWEST PARKWAY AUSTIN, TX 78735	utility engineering services	Invoice Cost	107	269,463
SYSTEMS CONTROL 3201 EAST INDUSTRIAL DRIVE IRON MOUNTAIN, MI 49801	substation control services	Invoice Cost	107	99,398
T&A TRUCKING 2754 PINE DRIVE NE NEW PHILADELPHIA, OH 44663	trucking services	Invoice Cost	107, 108, 163, 186, 570	161,947
TECHSERV CONSULTING & TRAINING 12078 STATE HWY 64 WEST TYLER, TX 75704	business consulting services	Invoice Cost	107, 108	83,218
TECHMARKET WORKS 165 WEST NETHERWOOD ROAD OREGON, WI 53575	energy industry researchers	Invoice Cost	908	307,706
TEMPORARY TECHNICAL SERVICES INC 915 AIRPORT ROAD JACKSON, MI 49202	engineering services	Invoice Cost	107, 108, 186, 580, 583 588	90,380
TERRACON CONSULTANTS INC 790 MORRISON ROAD COLUMBUS, OH 43230	environmental consulting services	Invoice Cost	107	174,330
THAYER POWER & COMMUNICATION LINE 7400 MARKET ROAD FAIRVIEW, PA 16415	power engineering services	Invoice Cost	186	259,908
THOMPSON ELECTRIC INC 49 NORTHMORELAND AVENUE MUNROE FALLS, OH 44262	electrical contracting services	Invoice Cost	186	97,659
TOWNSEND CORPORATION 101 SOUTH MAIN STREET PARKER CITY, IN 47368	tree trimming services	Invoice Cost	186, 562, 570, 582, 592	79,308
TREMCO ROOFING 3735 GREEN ROAD BEACHWOOD, OH 44122	roof information services	Invoice Cost	108	102,829
TRIPLE S TIRE CO INC 405 SOUTH 9TH STREET ELWOOD, IN 46036	tire services	Invoice Cost	512	71,726
UC SYNERGETIC INC 3440 LAKEMONT BLVD FORT MILL, SC 29708	plant engineering support	Invoice Cost	107, 108, 186, 580, 588 590, 593	98,491
UNDERWATER CONSTRUCTION CORP 110 PLAINS RD ESSEX, CT 06426	underwater construction services	Invoice Cost	107, 512, 513, 519, 529 542	317,112

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, 2013

Charges for Outside Professional & Other Consulting Services - Payments of $50,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
UNITED CONSTRUCTION CO INC 1340 OLD ROSEMAR ROAD PARKERSBURG, WV 26104	construction contracting services	Invoice Cost	107, 108, 530	2,968,553
UNITED CONVEYOR SUPPLY CO 2025 N 15TH AVENUE MELROSE PARK, IL 60160	fabricated metal product services	Invoice Cost	107	805,543
UNITED KISER SERVICES LLC 1001 STEPHENSON STREET NORWAY, MI 49870	turbine fabrication services	Invoice Cost	107, 108, 543	918,375
UNITED POWER LINE 486 W WELCH COURT TRAVERSE CITY, MI 49686	employment contractor services	Invoice Cost	186	328,587
UNITED RENTALS 100 FIRST STAMFORD PLACE STAMFORD, CT 06902	equipment rental services	Invoice Cost	107, 426, 511, 512, 513	101,572
UNIVERSAL INCORPORATED 32 PROGRESS PARKWAY MARYLAND HEIGHTS, MO 63043	specialty chemical services	Invoice Cost	107, 511, 513	165,647
UTILITY LOCATORS various US locations	power line construction services	Invoice Cost	107, 584	1,426,470
UTILX CORP P.O. BOX 97009 KENT, WA 98064	power cable services	Invoice Cost	107, 108	231,887
UTTER CONSTRUCTION INC 1302 STATE ROUTE 133 BETHEL, OH 45106	fly ash pond construction services	Invoice Cost	107, 501	5,470,797
VARO ENGINEERS INC 2751 TULLER PARKWAY, SUITE 100 DUBLIN, OH 43017	engineering services	Invoice Cost	107	195,411
VAUGHN INDUSTRIES 1201 E. FINDLAY STREET CAREY, OH 43316	substation electrical work services	Invoice Cost	107, 108, 571	1,282,431
WEIR VALVES & CONTROLS USA INC 28 OLD RIGHT ROAD IPSWICH, MA 01938	valve & control services	Invoice Cost	512	188,601
WESTINGHOUSE ELECTRIC CO 4350 NORTHERN PIKE MONROEVILLE, PA 15146	nuclear support services	Invoice Cost	120	438,268
WHAYNE SUPPLY CO 1400 CECIL AVENUE LOUISVILLE, KY 40211	equipment repair services	Invoice Cost	152, 501, 512, 513, 514 935	771,537
WIGHTMAN & ASSOCIATES, INC 110 E. WAYNE STREET FORT WAYNE, IN 46801	topographic surveying services	Invoice Cost	107, 186	346,448
WORLEYPARSONS GROUP INC 2675 MORGANTOWN ROAD READING, PA 19607	engineering services	Invoice Cost	107, 108, 183	4,468,764
WRIGHT TREE SERVICE INC 139 6TH STREET DESMOINES, IA 50306	tree trimming services	Invoice Cost	107, 570, 571, 592, 593 930	5,440,160

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 2013/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	18,314,892
3	Steam	10,039,344	23	Requirements Sales for Resale (See instruction 4, page 311.)	5,030,489
4	Nuclear	16,280,498	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	14,691,572
5	Hydro-Conventional	105,564	25	Energy Furnished Without Charge	57
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other		27	Total Energy Losses	2,161,086
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	40,198,096
9	Net Generation (Enter Total of lines 3 through 8)	26,425,406			
10	Purchases	13,772,690			
11	Power Exchanges:				
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)	40,198,096			

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 2013/Q4

MONTHLY PEAKS AND OUTPUT

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

NAME OF SYSTEM:

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	4,121,411	1,922,657	3,782	22	800
30	February	3,095,631	1,094,547	3,686	1	900
31	March	3,147,701	1,024,817	3,552	5	2000
32	April	2,363,702	460,849	3,244	2	700
33	May	2,695,519	676,928	3,854	30	1400
34	June	3,350,392	1,239,473	4,106	24	1600
35	July	4,158,801	1,893,644	4,500	17	1800
36	August	3,859,859	1,641,033	4,371	27	1700
37	September	3,425,753	1,429,360	4,540	10	1500
38	October	2,768,934	790,390	3,331	4	1400
39	November	3,109,398	1,105,271	3,514	25	1900
40	December	4,100,995	1,926,659	3,786	12	900
41	TOTAL	40,198,096	15,205,628			

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 2013/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)	667			655		
7	Plant Hours Connected to Load	8233			5871		
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	4683799000			3220098000		
13	Cost of Plant: Land and Land Rights	6508470			68095		
14	Structures and Improvements	93254937			6399473		
15	Equipment Costs	586393668			100054371		
16	Asset Retirement Costs	1333993			1310640		
17	Total Cost	687491068			107832579		
18	Cost per KW of Installed Capacity (line 17/5) Including	1041.6531			165.8963		
19	Production Expenses: Oper, Supv, & Engr	1620471			1627022		
20	Fuel	116751424			81821488		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	2325829			830189		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	764929			779585		
26	Misc Steam (or Nuclear) Power Expenses	1904443			2052180		
27	Rents	2117			70149368		
28	Allowances	3952026			3952026		
29	Maintenance Supervision and Engineering	1002786			1048714		
30	Maintenance of Structures	508115			177274		
31	Maintenance of Boiler (or reactor) Plant	4599368			6973350		
32	Maintenance of Electric Plant	1152098			2191840		
33	Maintenance of Misc Steam (or Nuclear) Plant	541942			349502		
34	Total Production Expenses	135125548			171952538		
35	Expenses per Net KWh	0.0288			0.0534		
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 2013/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: *TANNERS CREEK PLANT* (f)	Line No.
Steam	Steam	Steam	1
Conventional	Conventional	Conventional	2
1984	1984	1951	3
1989	1989	1964	4
1310.00	2620.00	995.00	5
1317	2634	986	6
8432	8432	6525	7
0	0	0	8
1310	2620	995	9
1308	2615	982	10
0	228	106	11
7903897000	15807815500	2135447000	12
6576565	13123804	4099388	13
99654410	201099717	53688464	14
686448039	1372797469	581111402	15
2644633	5220652	29774199	16
795323647	1592241642	668673453	17
607.1173	607.7258	672.0336	18
3247493	5887366	2888930	19
198572912	402425419	72644450	20
0	0	0	21
3156018	6382608	3846977	22
0	0	0	23
0	0	0	24
1544514	3089037	117195	25
3956623	6895142	3930832	26
70151485	138438746	3243	27
7904052	7904052	5683206	28
2051500	4026878	1580305	29
685389	1370839	828732	30
11572718	23159931	7294097	31
3343938	6685891	2878211	32
891444	1782799	1166605	33
307078086	608048708	102862783	34
0.0389	0.0385	0.0482	35

Coal	Oil		Coal	Oil		Coal	Oil		
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
4366414	18205	0	8732821	36410	0	1087408	12724	0	38
8813	136178	0	8813	136178	0	10333	136783	0	39
46.242	129.606	0.000	46.242	129.606	0.000	61.460	126.730	0.000	40
45.870	129.170	0.000	46.009	129.170	0.000	60.400	127.980	0.000	41
2.602	22.584	0.000	2.610	22.584	0.000	2.923	22.278	0.000	42
0.026	0.000	0.000	0.025	0.000	0.000	0.031	0.000	0.000	43
9825.000	0.000	0.000	9831.000	0.000	0.000	10558.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

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

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *DONALD C COOK PLANT* (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	
3	Year Originally Constructed	1975	
4	Year Last Unit was Installed	1978	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	2285.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	2241	0
7	Plant Hours Connected to Load	8760	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	2191	0
10	When Limited by Condenser Water	2059	0
11	Average Number of Employees	1062	0
12	Net Generation, Exclusive of Plant Use - KWh	16280498000	0
13	Cost of Plant: Land and Land Rights	1879588	0
14	Structures and Improvements	357274772	0
15	Equipment Costs	2067073434	0
16	Asset Retirement Costs	277556034	0
17	Total Cost	2703783828	0
18	Cost per KW of Installed Capacity (line 17/5) Including	1183.2752	0
19	Production Expenses: Oper, Supv, & Engr	18409849	0
20	Fuel	150381935	0
21	Coolants and Water (Nuclear Plants Only)	4432531	0
22	Steam Expenses	9470954	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	1842260	0
26	Misc Steam (or Nuclear) Power Expenses	90103820	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	10608570	0
30	Maintenance of Structures	3504124	0
31	Maintenance of Boiler (or reactor) Plant	66679782	0
32	Maintenance of Electric Plant	10976105	0
33	Maintenance of Misc Steam (or Nuclear) Plant	17551661	0
34	Total Production Expenses	383961591	0
35	Expenses per Net KWh	0.0236	0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Nuclear	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		
38	Quantity (Units) of Fuel Burned	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.869	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.009	0.000
44	Average BTU per KWh Net Generation	10632.000	0.000

FOOTNOTE DATA

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

The Rockport Plant is a two unit coal fired generating facility. Unit 1 is jointly owned and Unit 2 is jointly leased by the Respondent and AEP Generating Company. Column (b) represents Respondent's 50% share of Unit 1 and column (c) represents Respondent's 50% share of Unit 2. Column (d) represents Respondent's total share of Rockport Plant and column (e) represents Total Rockport owned and leased by Respondent and AEP Generating Company.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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	Hydroelectric					
2	Berrien Springs	1908	7.20	6.0	31,787	15,022,518
3	Buchanan	1919	4.10	3.0	16,781	7,460,956
4	Constantine	1921	1.20	1.0	4,560	2,759,786
5	Elkhart	1913	3.44	3.0	16,036	6,390,818
6	Mottville	1923	1.68	3.0	8,059	4,164,530
7	Twin Branch	1904	4.80	4.0	28,340	11,925,323
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						

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 2013/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
2,086,461	360,452		260,475			2
1,819,745	223,522		275,726			3
2,299,822	99,809		53,608			4
1,857,796	203,054		123,209			5
2,478,887	133,109		328,878			6
2,484,442	275,558		308,045			7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46

Name of Respondent	This Report is:	Date of Report	Year of Report
INDIANA MICHIGAN POWER COMPANY MICHIGAN	(1) [X] An Original (2) [ ] A Resubmission	(Mo,Da,Yr)	December 31, 2013

CHANGES MADE OR SCHEDULED TO BE MADE IN GENERATING PLANT CAPACITIES

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

A. Generating Plants or Units Dismantled, Removed 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 to Another, 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 Unit 1	Dry Sorbent Injection	1,320	Aug-13	May-15
9	Rockport Unit 2	Dry Sorbent Injection	1,300	Aug-13	Dec-14
10	Cook Unit 1	Life Cycle Management	1,134	Jul-11	Dec-18
11	Cook Unit 2	Life Cycle Management	1,107	Jul-11	Dec-18
12					
13					
14					

C. New Generating Plants Scheduled for or Under Construction

Line No.	Plant Name and Location (a)	Type (Hydro, Pumped Storage, Steam, Internal Combustion Gas-Turbine, Nuclear, 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 and Location (a)	Type (Hydro, Pumped Storage, Steam, Internal Combustion Gas-Turbine, Nuclear, etc) (b)	Unit No. (c)	Size of Unit (in megawatts) (d)	Estimated Dates of Construction Start (e)	Completion (f)
22	NONE					
23						
24						
25						
26						
27						
28						

This Page Intentionally
Left Blank

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, 2013

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 therof 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	Tanners Creek	Lawrenceburg, IN	1-1951	Pulv. Coal	2080	1050/1000	930
2							
3			2-1952	Pulv. Coal	2080	1050/1000	930
4							
5			3-1954	Pulv. Coal	2075	1050/1050	1,335
6							
7			4-1964	Coal-Cyclone	3500	1000/1025	3,840
8						/1050	
9							
10							
11							
12							
13							
14							
15	Donald C. Cook	Bridgman, MI	1-1975	Nuclear	2485	600	15,600
16			2-1978	Nuclear	2485	600	14,740
17							
18							
19							
20							
21	Rockport*	Rockport, IN	1-1984	Pulv. Coal	3650	1000/1000	9,775
22							
23			2-1989	Pulv. Coal	3650	1000/1000	9,775
24							
25							
26							
27							
28	* Figures shown are the totals for the plant which is shared one-half by respondent and one-half						
29	by AEP Generating Company (an associated company). Both companies are subsidiaries of American						
30	Electric Power Company. Operating expenses are shared on the basis of ownership percentage.						
31	Unit 1 is owned 50% by each and unit 2 is leased 50% by each from a consortium of financial institutions.						
32							
33							

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, 2013

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.)

Year Installed	TURBINES *Include both ratings for boiler and turbine-generator of dual-rated installations*				GENERATORS							Line No.
					NAME PLATE Rating in Kw		Hydrogen Pressure *(Designate air cooled generators)*		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))	
	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 psig.	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.				
(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	
1951	90	CC	Var.	1800	90,000	109,800	0.5	25	0.80	13.8	152,500	1
1951	35	CC	2000	3600	35,000	42,700	0.5	25	0.80	13.8		2
1952	90	CC	Var.	1800	90,000	109,800	0.5	25	0.80	13.8	152,500	3
1952	35	CC	2000	3600	35,000	42,700	0.5	25	0.80	13.8		4
1954	100	CC	Var.	1800	112,000	137,200	0.5	30	0.80	18	215,400	5
1954	60	CC	2000	3600	63,750	78,200	0.5	30	0.85	18		6
1964	580	CC	Var.	1800	108,000	238,850	0.5	45	0.85	20	579,700	7
1964		CC	3500	3600	108,000	340,850	0.5	45	0.85	20		8
											1,100,100	9
												10
												11
												12
												13
												14
1975	1149	TC	728	1800	771,840	1,152,000	30	75	0.90	26	1,152,000	15
1978	1162	TC	785	1800	933,850	1,133,333	40	60	0.85	26	1,133,333	16
											2,285,333	17
												18
												19
												20
1984	650	CC	600	3600	600,000	650,000	45	65	0.90	26	1,300,000	21
1984	650	CC	3650	3600	600,000	650,000	45	65	0.90	26		22
1989	650	CC	600	3600	600,000	650,000	45	65	0.90	26	1,300,000	23
1989	650	CC	3650	3600	600,000	650,000	45	65	0.90	26		24
											2,600,000	25
												26
												27
												28
												29
												30
												31
												32
												33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	STATE OF INDIANA							
2	6128 DUMONT	JEFFERSON	765.00	765.00	ALUM TOWER	202.76		1
3	6128 DUMONT	JEFFERSON	765.00	765.00	STEEL	0.24		
4	6136 DUMONT	WILTON CENTER	765.00	765.00	STEEL	63.00		1
5	6141 DUMONT	MARYSVILLE	765.00	765.00	STEEL	104.00		1
6	6215 D.C. COOK	DUMONT	765.00	765.00	STEEL	20.00		1
7	6223 ROCKPORT	JEFFERSON	765.00	765.00	STEEL	111.00		1
8	6224 ROCKPORT	SULLIVAN	765.00	765.00	STEEL	97.00		1
9	6226 JEFFERSON	WEST	765.00	765.00				
10	6236 HANGING ROCK	JEFFERSON	765.00	765.00	STEEL	1.00		1
11	0675 TANNERS CREEK	SORENSON	345.00	345.00	STEEL	136.00		2
12	0676 SORENSON	EAST LIMA	345.00	345.00	STEEL	30.00		1
13	0677 BREED	DEQUINE EAST	345.00	345.00	STEEL	188.19		2
14	0678 DEQUINE	OLIVE	345.00	345.00	STEEL	0.45		
15	0679 SORENSON	OLIVE	345.00	345.00	STEEL	78.00		2
16	0680 OLIVE	GOODINGS GROVE	345.00	345.00	STEEL	41.00		2
17	0683 DESOTO	JCT TOWER (MAR. CO)	345.00	345.00	STEEL	53.00	6.00	1
18	0684 TANNERS CREEK	JUNCTION TOWER	345.00	345.00	ST & ALUM	80.00		1
19	0685 HANNA	JUNCTION TOWER	345.00	345.00				
20	0687 TANNERS CREEK	MIAMI FORT	345.00	345.00	STEEL			2
21	0688 EUGENE	SIDNEY	345.00	345.00	WOOD POLE	2.00		1
22	0689 SORENSON-OLIVE	TWIN BRANCH	345.00	345.00	STEEL	11.00		2
23	0690 BREED	CIPSCO	345.00	345.00	STEEL	1.00		1
24	0691 BREED	PETERSBURG	345.00	345.00	STEEL	1.00		1
25	6118 ROBISON PARK	SORENSON-EAST LIMA	345.00	345.00	STEEL	23.00		1
26	6119 COOK	OLIVE	345.00	345.00	STEEL	4.00		2
27	6122 DUMONT	OLIVE	345.00	345.00	STEEL	15.00		2
28	6123 DUMONT	TWIN BRANCH	345.00	345.00	STEEL	17.00		2
29	6125 ROBISON PARK	EAST	345.00	345.00				
30	6133 DUMONT	BABCOCK	345.00	345.00	STEEL	9.00		1
31	6145 TWIN BRANCH	COOK-ROB PARK JCT	345.00	345.00	STEEL	6.00		2
32	6147 COOK	ROBISON PARK	345.00	345.00	STEEL	68.00		2
33	6148 JACKSON ROAD	SORENSON-OLIVE	345.00	345.00	STEEL	4.00		2
34	6213 COOK-ROB-PARK JCT	ARGENTA	345.00	345.00	STEEL	2.00		2
35	6237 JACKSON ROAD	WEST	345.00	345.00				
36					TOTAL	3,928.92	122.54	203

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 2013/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)	
								1
4-954 MCM								2
4-954 MCM								3
4-954 MCM								4
4-954 MCM								5
4-954 MCM								6
4-1351 MCM								7
4-1351 MCM								8
								9
4-1351 MCM								10
1275 MCM								11
1275 MCM								12
1414 MCM								13
2303 ACSR 54/37								14
1414 MCM								15
1414 MCM								16
2-954 MCM								17
2-954 MCM								18
								19
2-954 MCM								20
1414 MCM								21
1563 MCM								22
2-1024 MCM								23
2-954 MCM								24
1414 MCM								25
2-954 MCM								26
2-954 MCM								27
2-954 MCM								28
								29
2-954 MCM								30
2-954 MCM								31
2-954 MCM								32
2303 MCM								33
2-954 MCM								34
								35
	59,912,063	590,288,469	650,200,532	243,595	8,754,308		8,997,903	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 2013/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	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	6240 TWIN BRANCH	SUBSTATION CORRIDOR	345.00	345.00				
2	6256 BREED	SULLIVAN	345.00	345.00	STEEL	2.00		2
3	6259 COLLINGWOOD	SOUTH BUTLER	345.00	345.00	STEEL POLE	12.00		1
4	6127 EAST ELKHART TAP		138.00	138.00				
5	6232 GODMAN TAP		34.00	138.00				
6	0602 TWIN BRANCH	RIVERSIDE	138.00	138.00	STEEL	6.00		2
7	0603 TWIN BRANCH	SOUTH BEND	138.00	138.00	STEEL	5.00		1
8	0604 TWIN BRANCH	ROBISON PARK	138.00	138.00	STEEL	65.00		2
9	0605 SOUTH BEND	MICHIGAN CITY	138.00	138.00	STEEL			1
10	0606 ROBISON PARK	HAVILAND	138.00	138.00	STEEL	20.00		2
11	0607 ROBISON PARK	DEER CREEK	138.00	138.00	STEEL	60.00		2
12	0608 DEER CREEK	KOKOMO	138.00	138.00	STEEL	7.00		1
13	0609 CONCORD TAP		138.00	138.00	STEEL	4.00		2
14	0613 TWIN BRANCH	JACKSON ROAD	138.00	138.00	STEEL	8.00		2
15	0614 LINCOLN TAP		138.00	138.00	STEEL	4.00		2
16	0615 TWIN BRANCH	ROBISON PARK	138.00	138.00	STEEL	65.83		1
17	0616 DEER CREEK	DELAWARE	138.00	138.00	STEEL	24.50		2
18	0617 DELAWARE	MADISON	138.00	138.00	STEEL	19.00		2
19	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	STEEL TWR &	56.31		2
20	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	UNDERGROU	1.69		2
21	0725 DELAWARE	TRENTON	138.00	138.00	STEEL TWR &			
22	0619 MADISON	NEW CASTLE	138.00	138.00	STEEL	6.00	1.00	1
23	0620 TANNERS CREEK	MADISON	138.00	138.00	STEEL	82.00		2
24	0622 JACKSON ROAD	OLIVE	138.00	138.00	STEEL	17.00	1.00	1
25	0623 MADISON	PENDLETON	138.00	138.00	WOOD &	5.00		1
26	0624 DRAGOON TAP		138.00	138.00	STEEL	2.00		1
27	0625 TANNERS CREEK	COLLEGE CORNER	138.00	138.00	STEEL	40.00		2
28	0626 COLLEGE CORNER	RANDOLPH	138.00	138.00	WOOD	39.00		1
29	0627 RANDOLPH	JAY	138.00	138.00	WOOD	24.00		1
30	0628 MCKINLEY TAP		138.00	138.00	STEEL	1.00		2
31	0629 JAY	LINCOLN	138.00	138.00	WOOD &	49.00		1
32	0630 NEW CARLISLE	MAPLE	138.00	138.00	WOOD	1.00		1
33	6104 SORENSON	DEVILS HOLLOW	138.00	138.00	STEEL	3.00		2
34	0632 SORENSON	DEVILS HOLLOW	138.00	138.00	STEEL			
35	0634 DEER CREEK	MULLIN	138.00	138.00	WOOD	15.00		1
36					TOTAL	3,928.92	122.54	203

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 2013/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)	
								1
1351.5 MCM								2
2-954 MCM								3
								4
								5
397.5 MCM								6
397.5 MCM								7
397.5 MCM								8
397.5 MCM								9
397.5 MCM								10
397.5 MCM								11
336.4 MCM								12
397.5 MCM								13
447 MCM								14
397.5 MCM								15
477 MCM								16
397.5 MCM								17
397.5 MCM								18
397.5 MCM								19
397.5 MCM								20
397.5 MCM								21
795 MCM								22
636 MCM								23
556.5 MCM								24
477 MCM								25
795 MCM								26
636 MCM								27
556.5 MCM								28
556.5 MCM								29
300 MCM CU								30
556.5 MCM								31
397.5 MCM								32
556.5 MCM								33
556.5 MCM								34
556.5 MCM								35
	59,912,063	590,288,469	650,200,532	243,595	8,754,308		8,997,903	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 2013/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	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	0635 PENDLETON	MULLIN	138.00	138.00	WOOD &	16.00		1
2	0636 DEER CREEK	FISHER BODY	138.00	138.00	STEEL	5.04		2
3	0637 TWIN BRANCH	CONCORD	138.00	138.00	STEEL	17.00	1.00	1
4	0638 GRANT	FISHER BODY	138.00	138.00	STEEL		1.00	1
5	0639 ROBISON PARK	AUBURN	138.00	138.00	WOOD &	15.00		1
6	0641 DESOTO	MEDFORD	138.00	138.00	STEEL	7.00		2
7	0642 OLIVE	HICKORY CREEK	138.00	138.00	STEEL	3.00	2.00	1
8	0645 COREY TAP		138.00	138.00	WOOD	4.00		1
9	0646 OLIVE	NEW CARLISLE	138.00	138.00	STEEL	2.00		1
10	0647 OLIVE	SOUTH BEND	138.00	138.00	STEEL	1.00	16.00	1
11	0648 MEDFORD TAP		138.00	138.00	STEEL	8.00		2
12	0714 EAST SIDE STA ENTR		138.00	138.00	UNDERGROU			1
13	0723 SPY RUN STATION		138.00	138.00	UNDERGROU			1
14	6101 WESTINGHOUSE TAP		138.00	138.00	STEEL	2.00		2
15	6102 MILAN TAP		138.00	138.00	STEEL	6.00		2
16	6103 MILAN	GOODRICH	138.00	138.00	STEEL	1.00		2
17	6105 DESOTO	JAY	138.00	138.00	WOOD &	13.00		1
18	6106 DESOTO	DEER CREEK-DELAWARE	138.00	138.00	STEEL	8.00		2
19	6107 DARDEN TAP		138.00	138.00	WOOD	1.00		1
20	6109 ROBISON PARK	RICHLAND	138.00	138.00	WOOD &	18.00		1
21	6110 WESTINGHOUSE	23RD STREET	138.00	138.00	STEEL			2
22	6111 KANKAKEE	WEST SIDE	138.00	138.00	WOOD POLE	2.00		1
23	6113 INDUSTRIAL PARK		138.00	138.00	STEEL	3.00		2
24	6114 OLIVE	MICHIGAN CITY	138.00	138.00	STEEL	2.00	1.00	1
25	6115 HUMMEL CREEK	VAN BUREN	138.00	138.00	STEEL	6.00		2
26	6130 HUMMEL CREEK	TOWER 70, GREENTOWN	138.00	138.00				
27	6116 SOUTH ELWOOD TAP		138.00	138.00	WOOD POLE	3.00		1
28	6117 PENDLETON	FALL CREEK	138.00	138.00	STEEL	10.00		2
29	6121 ROBISON PARK	LINCOLN	138.00	138.00	STEEL	8.00		1
30	6126 CONCORD	EAST ELKHART	138.00	138.00	STEEL	11.00		1
31	6129 GREENTOWN-GRANT	HUMMEL CREEK	138.00	138.00	STEEL	21.00		1
32	6131 INDUSTRIAL PARK	MC KINLEY	138.00	138.00	WOOD POLE	5.00		1
33	6132 CROSS STREET TAP	JUNCTION TOWER #88	138.00	138.00	WOOD POLE	4.00		1
34	6134 LINCOLN	ANTHONY	138.00	138.00	WOOD POLE	3.00		1
35	6135 WAYNEDALE TAP		138.00	138.00	STEEL			2
36					TOTAL	3,928.92	122.54	203

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 2013/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)	
556.5 MCM								1
397.5 MCM								2
556.5 MCM								3
397.5 MCM								4
556.5 MCM								5
556.5 MCM								6
556.5 MCM								7
477 MCM								8
556.5 MCM								9
556.5 MCM								10
556.5 MCM								11
795 MCM								12
3.5IN OD								13
556.5 MCM								14
397.5 MCM								15
397.5 MCM								16
2-556.5 MCM								17
636 MCM								18
336.4 MCM								19
636 MCM								20
556.5 MCM								21
636 MCM								22
745 MCM								23
636 MCM								24
795 MCM								25
								26
556.5 MCM								27
795 MCM								28
795 MCM								29
795 MCM								30
795 MCM								31
795 MCM								32
795 MCM								33
795 MCM								34
795 MCM								35
	59,912,063	590,288,469	650,200,532	243,595	8,754,308		8,997,903	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 2013/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	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	6138 JACKSON ROAD	SOUTH SIDE	138.00	138.00	WOOD POLE	2.00		1
2	6142 ALBION	KENDALLVILLE	138.00	138.00	WOOD POLE	10.00		1
3	6150 SOUTHSIDE	SOUTH BEND	138.00	138.00	WOOD &	6.07		1
4	6219 DELCO BATTERY TAP		138.00	138.00	STEEL POLE	1.00		2
5	6220 FALL CREEK	MADISON-NEW CASTLE	138.00	138.00	STEEL	1.00		2
6	6225 INDUSTRIAL PARK	SPY RUN	138.00	138.00	WOOD POLE	4.00		1
7	6266 WALLEN		138.00	138.00	STEEL POLE	0.22		1
8	6234 CABOT TAP/CR 4	EAST ELKHART	138.00	138.00	WOOD POLE	0.13		1
9	6238 SORENSON	MCKINLEYTOWER	138.00	138.00	STEEL	3.13		2
10	6241 KENDALLVILLE TAP	CITY OF AUBURN #5	138.00	138.00	WOOD H-FR	14.00		1
11	6242 AUBURN	CITY OF AUBURN #5	138.00	138.00	WOOD POLE	2.00		1
12	6245 LAPORTE JCT	LIQUID CARBONICS	138.00	138.00	WOOD POLE	5.00		1
13	6246 LAPORTE JCT	AIRCO	138.00	138.00	WOOD POLE	1.00		1
14	6248 ELCONA TAP	CONC-DUN-E-ELK	138.00	138.00	WOOD POLE	2.00		1
15	6249 ALLEN	LINCOLN	138.00	138.00	STEEL	5.00		2
16	6250 ALLEN	ADAMS/HILLCREST	138.00	138.00	STEEL	5.00		2
17	6251 OLIVE	EDISON	138.00	138.00	STEEL	1.00		2
18	6253 TRIER RD TAP		138.00	138.00	STEEL POLE			1
19	6258 KENZIE CREEK	TWIN BRANCH	138.00	138.00	STEEL			2
20	6260 WILMINGTON TAP		138.00	138.00	WOOD POLE	1.00	9.00	1
21	6229 DUNLAP NORTH TAP		34.00	138.00	WOOD POLE	2.00		2
22	6140 INDIANA-PURDUE		34.00	138.00	STEEL POLE			2
23	6217 HILLCREST	KINNERK	69.00	138.00	WOOD POLE	4.00		1
24	6252 KENDALLVILLE	BIXLER	138.00	138.00	WOOD POLE	2.00		1
25	6254 ALLEN/LINCOLN	ALLEN/HILLCREST	138.00	138.00				
26	6265 CONCORD	WOLF	138.00	138.00	WOOD POLE	0.56	0.54	1
27	INDALEX TAP/CR 4	EAST ELKHART	138.00	138.00	WOOD POLE	1.09		
28	6267 STUDEBAKER	WEST SIDE	138.00	138.00	WOOD POLE	1.41		1
29			138.00	138.00	STEEL	1.11		1
30	6270 JONES CREEK	HOGAN	138.00	138.00		5.62		
31	LINES<132 KV	SYSTEM	69.00		WOOD,	921.78	72.00	1
32								
33	STATE OF MICHIGAN							
34	6216 D.C. COOK	DUMONT	765.00	765.00	STEEL	16.00		1
35	6120 COOK	PALISADES	345.00	345.00	STEEL	42.00		2
36					TOTAL	3,928.92	122.54	203

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 2013/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)	
795 MCM								1
795 MCM								2
795 MCM								3
795 MCM AA								4
795 MCM								5
1033 MCM								6
1033.5 KCM								7
556.5 MCM								8
795 MCM								9
795 MCM								10
795 MCM								11
795 MCM								12
795 MCM								13
795 MCM								14
1033 MCM								15
1033 MCM								16
795 MCM								17
795 MCM								18
1033 MCM								19
2-954 MCM								20
795 MCM								21
1033 MCM								22
795 MCM								23
795 MCM								24
								25
336.4 ACSR KCM								26
								27
954 MCM								28
954 MCM								29
								30
VARIOUS								31
								32
								33
4-954 MCM								34
2-954 MCM								35
	59,912,063	590,288,469	650,200,532	243,595	8,754,308		8,997,903	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 2013/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	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	6143 D.C. COOK	OLIVE-PALISADES	345.00	345.00	STEEL	5.00		2
2	6144 TWIN BRANCH	COOK-ROB PARK JCT	345.00	345.00	STEEL			2
3	6151 COOK	OLIVE	345.00	345.00				
4	6152 COOK	ROBINSON PARK	345.00	345.00				
5	6146 D.C. COOK	ROBISON PARK	345.00	345.00	STEEL	37.00		2
6	6214 COOK-ROB PARK	ARGENTA	345.00	345.00	STEEL	29.00		2
7	6221 D.C. COOK	OLIVE-PALISADES	345.00	345.00	STEEL	5.00		2
8	6263 BARODA TAP		138.00	138.00				
9	0601 TWIN BRANCH	RIVERSIDE	138.00	138.00	STEEL	33.00		2
10	0610 AUTO SPECIALTIES		138.00	138.00				
11	0621 TWIN BRANCH - R	HICKORY CREEK	138.00	138.00	STEEL	5.00		2
12	0644 RIVERSIDE	HARTFORD	138.00	138.00	WOOD	16.33		1
13	0649 COREY TAP		138.00	138.00	WOOD	13.00		1
14	6108 RIVERSIDE	OLIVE-HICKORY CREEK	138.00	138.00	WOOD &	6.00		1
15	6124 BENTON HARBOR	RIVERSIDE-HARTFORD	138.00	138.00	STEEL	1.00		2
16	6137 EDGEWATER TAP		138.00	138.00	WOOD POLE	0.76		1
17	6139 BENTON HARBOR	TWIN BRANCH-R SIDE	138.00	138.00	STEEL	6.00		2
18	6149 HARTFORD	COREY	138.00	138.00	WOOD POLE	41.00		1
19	6218 MOTTVILLE TAP		138.00	138.00	WOOD POLE	1.00		1
20	6255 KENZIE CREEK	VALLEY	138.00	138.00	WOOD POLE	20.00		1
21	6257 KENZIE CREEK	T B/R'SIDE/HICK CR	138.00	138.00	STEEL			
22	6261 FLATBUSH TAP		138.00	138.00		1.00		1
23	6262 WEST ST TAP		138.00	138.00		1.00		2
24	6700 GM HYDRAMATIC		138.00	138.00	STEEL	2.00		2
25	6227 NICKERSON	TOWER #13A	138.00	138.00				
26	0643 OLIVE	HICKORY CREEK	138.00	138.00				
27	6268 SAUK TRAIL		138.00	138.00	STEEL	1.60		
28	LESS THAN 132 KV LINES		69.00		WOOD,	425.10	12.00	
29								
30	Line cost and expense are	not available by individual						
31	transmission line.	Total shown in column j-p						
32								
33								
34								
35								
36					TOTAL	3,928.92	122.54	203

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 2013/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 MCM								1
2-954 MCM								2
								3
								4
2-954 MCM								5
2-954 MCM								6
2-954 MCM								7
								8
397.5 MCM								9
								10
397.5 MCM								11
397.5 MCM								12
477 MCM								13
636 MCM								14
795 MCM								15
556.5 MCM								16
795 MCM								17
795 MCM								18
795 AA								19
1033 MCM								20
795 MCM								21
								22
								23
795 MCM								24
								25
								26
1033.5KCM								27
VARIOUS								28
								29
								30
	59,912,063	590,288,469	650,200,532	243,595	8,754,308		8,997,903	31
								32
								33
								34
								35
	59,912,063	590,288,469	650,200,532	243,595	8,754,308		8,997,903	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 2013/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		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From	To		Type	Average Number per Miles	Present	Ultimate
	(a)	(b)	(c)	(d)	(e)	(f)	(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							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL						

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	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
									44

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 2013/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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	ADAMS (IM)-IN	T	138.00	69.00	34.00
2		T	138.00	13.00	
3	ALBION-IN	T	138.00	69.00	12.00
4		T	138.00		
5		T	69.00	12.00	
6		T	69.00		
7	ALEXANDRIA-IN	D	34.50	13.00	
8		D	34.50	4.00	
9		D	34.50		
10	ALLEN (IM)-IN	T	345.00	137.50	13.80
11	ALMENA-MI	T	69.00	34.50	
12		T	69.00	34.00	
13		T	69.00	12.00	
14	ANCHOR HOCKING (IM)-IN	D	69.00	13.00	
15		D	69.00	2.40	
16	ANTHONY-IN	T	138.00	34.00	
17		T	34.50	12.00	
18	ARMSTRONG CORK-IN	D	69.00	4.00	
19	ARNOLD HOGAN-IN	T	138.00	34.00	
20		T	138.00	13.09	
21		T	34.50		
22	AUBURN-IN	T	138.00	69.00	34.00
23		T	138.00		
24	BARODA-MI	D	138.00	13.09	
25	BEECH ROAD-IN	D	138.00	13.09	
26	BENTON HARBOR-MI	T	345.00	137.50	13.80
27		T	345.00	137.50	13.14
28	BERNE-IN	D	69.00	12.00	
29		D	69.00		
30	BERRIEN SP HYDR STAT-MI	T	34.50	13.00	
31		T	34.50	12.00	
32		T	34.50		
33	BETHEL-IN	D	34.50	13.00	
34	BIXLER-IN	D	138.00	13.09	
35	BLAINE STREET-IN	D	34.50	13.00	
36	BLUFF POINT-IN	T	138.00	69.50	13.09
37		T	69.00	13.00	
38		T	69.00		
39	BREED-IN	T	345.00		
40		T	345.00	14.40	

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
115	1					1
13	1					2
90	1					3
			STATCAP	1	53	4
8	1					5
			STATCAP	1	14	6
22	1					7
6	1					8
			STATCAP	1	7	9
450	1					10
30	1					11
22	1					12
7	1					13
20	1					14
14	2					15
112	1					16
29	2					17
20	2					18
30	1					19
22	1					20
			STATCAP	2	29	21
30	1					22
			STATCAP	2	106	23
20	1					24
20	1					25
450	1					26
224		1				27
20	1					28
			STATCAP	1	16	29
5	1					30
5	1					31
			STATCAP	1	10	32
11	1					33
20	1					34
29	2					35
60	1					36
6	1					37
			STATCAP	1	16	38
			REACTOR	1	250	39
65	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 2013/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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	BRIDGMAN-MI	D	69.00	12.00	
2		D	69.00		
3	BUCHANAN HYDRO STA-MI	T	69.00	34.00	
4		T	69.00	12.00	
5	BUCHANAN SOUTH-MI	D	69.00	12.00	
6	BUTLER (IM)-IN	D	69.00	13.00	
7		D	69.00		
8	CALVERT-IN	D	138.00	13.09	
9	CAPITAL AVENUE-IN	T	138.00	13.09	
10	CHURUBUSCO-IN	D	34.50	13.00	
11		D	34.50		
12	CLEVELAND-IN	D	138.00	13.09	
13	COLBY-MI	T	138.00	69.00	34.50
14		T	138.00	13.09	
15		T	69.00	34.50	
16		T	34.50		
17	COLFAX-IN	D	34.50	12.00	
18	COLOMA Y-MI	T	69.00	34.00	
19		T	69.00		
20	COLONY BAY-IN	D	69.00	13.00	
21		D	69.00	12.00	
22	COLUMBIA(IM)-IN	T	138.00	69.00	34.00
23		T	138.00	34.00	
24	CONANT-IN	D	34.50	12.00	
25	CONCORD-IN	T	138.00	34.00	
26		T	138.00	13.09	
27		T	138.00		
28		T	34.50		
29	COREY-MI	T	138.00	69.00	34.50
30		T	69.00		
31	COUNTRYSIDE-IN	D	138.00	12.47	
32	COUNTY LINE (IM)-IN	D	138.00	13.09	
33	COUNTY ROAD 4-IN	D	138.00	13.09	
34	CROSS STREET-IN	D	138.00	13.09	
35	CRYSTAL-MI	D	138.00	13.09	
36	DALEVILLE-IN	D	138.00	13.09	
37	DARDEN ROAD-IN	D	138.00	13.09	
38	DC COOK EHV-MI	T	765.00	345.00	34.50
39		T	765.00	345.00	34.00
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 2013/Q4

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
19	2					1
			STATCAP	1	14	2
20	1					3
8	1					4
22	1					5
20	1					6
			STATCAP	2	30	7
20	1					8
12	1					9
11	1					10
			STATCAP	1	5	11
20	1					12
75	1					13
8	1					14
20	1					15
			STATCAP	1	17	16
22	1					17
22	1					18
			STATCAP	1	14	19
22	1					20
20	1					21
50	1					22
20	1					23
22	1					24
50	1					25
45	2					26
			STATCAP	1	53	27
			STATCAP	1	14	28
130	1					29
			STATCAP	1	14	30
20	1					31
20	1					32
20	1					33
20	1					34
22	1					35
20	1					36
42	2					37
2250	3	1				38
500		4				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 2013/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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	DECATUR (FTW)-IN	T	69.00	34.00	
2		T	69.00	13.00	
3		T	69.00	4.00	
4		T	69.00		
5	DEER CREEK-IN	T	138.00	69.00	34.00
6		T	138.00	34.50	
7		T	138.00	13.09	
8		T	138.00		
9		T	34.50	13.09	
10		T	34.50	11.00	4.00
11		T	34.50		
12	DELAWARE (IM)-IN	T	138.00	34.00	
13		T	138.00		
14		T	34.50		
15	DERBY-MI	T	138.00	69.00	34.50
16	DESOTO-IN	T	345.00	138.00	34.50
17	DIEBOLD ROAD-IN	D	69.00	13.00	
18	DOOVILLE-IN	D	138.00	13.09	
19	DRAGOON-IN	T	138.00	69.00	34.00
20		T	34.50		
21	DREWRYS-IN	D	34.50	13.09	
22		D	34.50	12.00	
23	DUMONT-IN	T	765.00		
24		T	765.00	345.00	34.50
25		T	765.00	345.00	17.00
26	DUNLAP-IN	T	138.00	69.00	34.00
27		T	138.00	13.09	
28		T	34.50		
29	EAST ELKHART-IN	T	345.00	137.50	13.80
30		T	138.00	69.00	34.00
31		T	34.50	7.20	
32	EAST SIDE (IM)-IN	D	138.00	13.09	
33	ELCONA-IN	D	138.00	13.09	
34	ELKHART HYDRO STAT-IN	T	34.50	13.00	
35		T	34.50		
36	ELLISON ROAD-IN	T	138.00	13.09	
37	ELMRIDGE-IN	D	34.50	13.00	
38	ELWOOD (IM)-IN	D	34.50	13.00	
39		D	34.50		
40	FAIRMOUNT-IN	D	34.50	7.20	

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
20	1					1
20	1					2
5	1					3
			STATCAP	1	13	4
90	1					5
75	1					6
20	1					7
			STATCAP	1	58	8
4	1					9
20	1					10
			STATCAP	2	30	11
125	2					12
			STATCAP	1	53	13
			STATCAP	2	59	14
75	1					15
675	1					16
20	1					17
12	1					18
84	1					19
			STATCAP	1	12	20
8	1					21
8	1					22
			REACTOR	9	750	23
1500	3					24
1500	3					25
130	1					26
40	2					27
			STATCAP	1	29	28
450	1					29
84	1					30
1		1				31
37	2					32
22	1					33
8	1					34
			STATCAP	1	14	35
20	1					36
9	1					37
19	2					38
			STATCAP	1	5	39
11	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 2013/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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	FALL CREEK-IN	T	345.00	138.00	34.50
2		T	345.00	138.00	34.00
3	FERGUSON-IN	D	69.00	13.00	
4	FISHER BODY-IN	D	138.00	13.80	
5	FLORENCE ROAD-MI	D	69.00	12.00	
6		D	69.00		
7	FULTON (IM)-IN	D	34.50	13.00	
8	GARRETT (IM)-IN	T	69.00	34.50	
9		T	34.50	13.00	
10	GAS CITY-IN	D	34.50	13.00	
11		D	34.50		
12	GATEWAY (IM)-IN	T	69.00	34.00	
13		T	69.00		
14	GE TAYLOR STREET-IN	T	34.50	13.00	
15	GERMAN-IN	D	138.00	13.09	
16	GLENBROOK-IN	D	34.50	13.00	
17	GRABILL-IN	D	138.00	13.09	
18	GRANGER-IN	D	138.00	13.09	
19		D	138.00	12.47	
20	GRANT-IN	T	138.00	34.00	
21		T	138.00	13.09	
22	GREENLEAF-IN	D	34.50	13.09	
23	GREENTOWN-IN	T	765.00		
24	HACIENDA-IN	D	138.00	13.09	
25		D	138.00	12.47	
26	HADLEY-IN	D	69.00	13.00	
27	HAGAR-MI	D	69.00	12.00	
28	HAMILTON-IN	D	69.00	13.00	
29	HARLAN-IN	D	69.00	13.09	
30		D	69.00	13.00	
31	HARPER-IN	D	138.00	13.09	
32	HARTFORD-MI	T	138.00	69.00	34.00
33		T	69.00	12.00	
34	HARTFORD CITY-IN	T	69.00	34.00	
35		T	69.00	13.00	
36		T	69.00		
37	HARVEST PARK-IN	D	34.50	13.00	
38	HAWTHORNE-MI	D	69.00	12.00	
39	HAYMOND-IN	D	34.50	13.00	
40					

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
675	1					1
672	1					2
20	1					3
100	2					4
20	1					5
			STATCAP	1	19	6
20	1					7
13	1					8
1	3					9
20	1					10
			STATCAP	1	10	11
20	1					12
			STATCAP	1	13	13
29	4					14
47	2					15
40	2					16
20	1					17
20	1					18
20	1					19
30	1					20
	1					21
20	1					22
			REACTOR	3	300	23
20	1					24
25	1					25
40	2					26
11	1					27
11	1					28
13	1					29
5	1					30
20	1					31
129	1					32
11	1					33
20	1					34
20	1					35
			STATCAP	1	16	36
20	1					37
22	1					38
24	2					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 2013/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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	HICKORY CREEK-MI	T	138.00	69.00	34.50
2		T	138.00	34.50	
3		T	34.50	12.00	
4		T	34.50		
5	HILLCREST-IN	T	138.00	69.00	34.00
6		T	138.00	13.09	
7		T	138.00		
8	HUMMEL CREEK-IN	T	138.00	69.00	34.00
9		T	138.00	13.09	
10	ILLINOIS ROAD-IN	T	138.00	69.00	13.00
11		T	138.00	13.09	
12	INDUSTRIAL PARK-IN	T	138.00	69.00	34.00
13		T	138.00	13.09	
14		T	138.00		
15		T	34.50	13.00	
16		T	34.50		
17	IRELAND ROAD-IN	D	138.00	13.09	
18	IU PURDUE-IN	D	34.50	13.00	
19		D	34.50	12.00	
20		D	13.80	4.00	
21	JACKSON ROAD-IN	T	345.00	138.00	34.00
22		T	138.00	34.00	
23		T	138.00	13.09	
24		T	34.50		
25	JAY (IM)-IN	T	138.00	69.00	34.00
26		T	138.00	13.09	
27		T	138.00		
28	JEFFERSON (IM)-IN	T	765.00		
29		T	765.00	345.00	34.00
30		T	138.00		
31	JONES CREEK-IN	D	138.00	12.47	
32	KANKAKEE-IN	T	138.00	34.00	11.00
33		T	138.00	13.09	
34	KENDALLVILLE-IN	T	138.00	69.00	13.00
35		T	138.00		
36		T	69.00	13.00	
37		T	69.00	12.00	
38	KENZIE CREEK-MI	T	345.00	137.50	13.80
39	KLINE-IN	T	138.00	34.00	
40		T	34.50		

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
75	1					1
60	2					2
31	2					3
			STATCAP	1	31	4
84	1					5
42	2					6
			STATCAP	1	53	7
75	1					8
20	1					9
84	1					10
20	1					11
75	1					12
22	1					13
			STATCAP	1	50	14
22	1					15
			STATCAP	1	16	16
20	1					17
20	1					18
22	1					19
5	1					20
672	1					21
30	1					22
32	2					23
			STATCAP	1	14	24
115	1					25
9	1					26
			STATCAP	1	58	27
			REACTOR	9	750	28
1500	3					29
			REACTOR	1	20	30
20	1					31
50	1					32
22	1					33
75	1					34
			STATCAP	1	43	35
8	1					36
11	1					37
450	1					38
100	1					39
			STATCAP	1	14	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 2013/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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	LAKE STREET-MI	T	69.00	34.00	
2		T	69.00		
3	LAKEHEAD-MI	D	69.00	13.00	
4	LANGLEY (IM)-MI	D	34.50	13.00	
5	LANTERN PARK-IN	D	138.00	13.09	
6	LAPORTE JUNCTION-IN	T	138.00	69.00	34.00
7	LIGONIER-IN	D	138.00	13.09	
8	LINCOLN-IN	T	138.00	34.00	11.00
9		T	138.00	13.09	
10		T	138.00		
11		T	34.50		
12	LINWOOD (IM)-IN	D	138.00	13.09	
13	LUSHER AVENUE-IN	D	34.50	12.00	
14	LYDICK-IN	D	34.50	13.09	
15	MADISON (IM)-IN	T	138.00	35.00	
16		T	34.50	13.09	
17	MAGLEY-IN	T	138.00	69.00	13.00
18		T	69.00	13.00	
19	MAIN STREET-MI	T	138.00	34.00	
20		T	138.00	13.09	
21		T	34.50	4.00	
22		T	34.50		
23	MARATHON OIL (IM)-IN	D	69.00	4.00	
24	MARION ETHANOL-IN	D	34.50	4.00	
25	MARION PLANT-IN	D	34.50	13.00	
26		D	34.50	4.00	
27		D	34.50		
28	MAYFIELD-IN	D	138.00	13.09	
29	MCGALLIARD ROAD-IN	D	34.50	13.00	
30	MCKINLEY-IN	T	138.00	69.00	34.00
31		T	138.00	34.00	
32		T	138.00	13.09	
33		T	138.00		
34		T	69.00		
35		T	34.50		
36	MEADOWBROOK-IN	T	138.00	35.00	
37		T	34.50		
38	MEDFORD-IN	T	138.00	69.00	34.00
39		T	34.50		
40	MIER-IN	D	138.00	13.09	

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
40	1					1
			STATCAP	1	26	2
11	1					3
17	2					4
20	1					5
84	1					6
29	2					7
100	6					8
20	1					9
			STATCAP	1	53	10
			STATCAP	2	29	11
11	1					12
20	1					13
20	1					14
60	1					15
5	1					16
90	1					17
9	1					18
30	1					19
22	1					20
8	1					21
			STATCAP	1	14	22
6	1					23
11	1					24
22	1					25
6	1					26
			STATCAP	1	9	27
20	1					28
29	2					29
84	1					30
112	1					31
40	2					32
			STATCAP	1	86	33
			STATCAP	1	22	34
			STATCAP	2	29	35
100	1					36
			STATCAP	1	29	37
75	1					38
			STATCAP	1	15	39
11	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 2013/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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	MISSISSINEWA-IN	D	138.00	13.09	
2	MODOC-IN	T	138.00	69.00	13.00
3		T	69.00	13.00	
4	MONTPELIER-IN	D	69.00	13.00	
5	MOORE PARK-MI	T	138.00	69.00	34.50
6		T	138.00	13.09	
7		T	69.00		
8	MOTTVILLE-MI	T	138.00	69.00	34.00
9		T	69.00	12.00	
10	MULLIN-IN	T	138.00	34.00	
11		T	34.50		
12	MURCH-MI	D	69.00	12.00	
13		D	69.00		
14	NEW BUFFALO-MI	D	69.00	12.00	
15		D	69.00		
16	NEW CARLISLE-IN	T	138.00	34.50	
17		T	34.50	13.00	
18	NICKERSON-MI	D	138.00	13.09	
19	NILES-MI	T	69.00	34.00	
20		T	69.00	13.09	
21		T	69.00		
22	NOBLE-IN	D	69.00	13.00	
23	NORTH KENDALLVILLE-IN	D	69.00	12.00	
24	NORTH PORTLAND-IN	D	69.00	13.00	
25	NORTHLAND-IN	D	138.00	13.09	
26	NORTHWEST ELKHART-IN	D	34.50	13.00	
27		D	34.50	12.00	
28		D	34.50		
29	OHIO OIL-IN	D	34.50	2.40	
30	OLIVE-IN	T	345.00	138.00	34.50
31		T	138.00	69.00	34.00
32		T	138.00	13.09	
33	OSOLO-IN	T	138.00	69.00	34.00
34		T	138.00	13.09	
35		T	34.50		
36	OSSIAN-IN	D	69.00	13.00	
37	PARNELL-IN	D	34.50	13.09	
38		D	34.50	13.00	
39	PEARL STREET-MI	D	34.50	12.00	
40					

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
12	1					1
60	1					2
5	1					3
22	1					4
90	1					5
20	1					6
			STATCAP	1	16	7
90	1					8
3	1					9
30	1					10
			STATCAP	1	20	11
20	1					12
			STATCAP	1	26	13
31	2					14
			STATCAP	1	29	15
30	1					16
8	1					17
20	1					18
45	1					19
20	1					20
			STATCAP	1	14	21
11	1					22
22	1					23
20	1					24
32	2					25
20	1					26
11	1					27
			STATCAP	1	14	28
6	6					29
675	1					30
27	1					31
9	1					32
75	1					33
42	2					34
			STATCAP	1	14	35
20	1					36
20	1					37
20	1					38
17	2					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 2013/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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	PENDLETON-IN	T	138.00	35.00	
2		T	34.50		
3	PETTIT AVENUE-IN	D	34.50	13.00	
4	PIGEON RIVER-MI	D	69.00	12.00	
5	PINE ROAD-IN	D	138.00	13.09	
6	PIPE CREEK-IN	D	138.00	12.00	
7	POKAGON(MBH)-MI	T	138.00	69.00	13.00
8		T	69.00	13.00	
9		T	69.00		
10	PORTLAND (IM)-IN	D	69.00	13.00	
11	PRICE-IN	D	69.00	13.09	
12	RANDOLPH-IN	T	138.00	69.00	13.00
13		T	138.00	13.09	
14		T	69.00		
15		T	34.50	12.00	
16	REED-IN	D	138.00	13.09	
17	RIVERSIDE (IM)-MI	T	138.00	69.00	34.00
18		T	138.00	13.09	
19		T	138.00		
20	ROBISON PARK-IN	T	345.00	138.00	13.00
21		T	138.00		
22		T	138.00	70.50	36.20
23		T	138.00	13.09	
24	ROCKPORT-IN	T	765.00		
25		T	765.00		
26		T	765.00		
27		T	138.00		
28		T	34.50	13.00	
29	ROYERTON-IN	D	138.00	13.09	
30	SAUK TRAIL-MI	D	138.00	13.09	
31	SCHOOLCRAFT-MI	D	69.00	13.00	
32	SCOTTDALE-MI	D	34.50	13.09	
33		D	34.50	13.00	
34	SELMA PARKER-IN	T	138.00	13.09	
35	SILVER LAKE-IN	D	34.50	12.00	
36	SISTER LAKES-MI	D	34.50	12.00	
37	SODUS-MI	D	138.00	13.09	
38	SORENSON-IN	T	345.00	138.00	34.00
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
125	2					1
			STATCAP	2	47	2
20	1					3
20	1					4
20	1					5
20	1					6
115	1					7
5	1					8
			STATCAP	1	14	9
17	2					10
20	1					11
56	1					12
22	1					13
			STATCAP	1	14	14
4	1					15
22	1					16
134	2					17
20	1					18
			STATCAP	1	106	19
672	1					20
			STATCAP	1	86	21
90	1					22
40	2					23
			REACTOR	2	50	24
	1					25
			REACTOR	3	200	26
			REACTOR	2	40	27
2	2	1				28
11	1					29
20	1					30
22	1					31
9	1					32
11	1					33
11	1					34
20	1					35
15	2					36
11	1					37
1347	2					38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	SOUTH BEND-IN	T	138.00	69.00	34.00
2		T	138.00	34.00	
3		T	138.00	13.09	
4		T	138.00		
5	SOUTH BERNE-IN	D	69.00	12.00	
6	SOUTH DECATUR-IN	D	69.00	13.09	
7		D	69.00	13.00	
8	SOUTH ELWOOD-IN	T	138.00	34.00	
9		T	138.00	13.09	
10	SOUTH SIDE (MARION)-IN	D	34.50	13.09	
11	SOUTH SIDE (SOUTH BEND)-IN	D	138.00	13.09	
12	SOYA-IN	D	34.50	4.00	
13	SPRING STREET-IN	D	34.50	13.00	
14		D	34.50	12.00	
15	SPY RUN-IN	T	138.00	34.00	
16		T	138.00	13.09	
17		D	34.50		
18		D	34.50	12.00	
19		D	34.50	4.00	
20	ST. JOE-IN	D	69.00	13.09	
21	STATE STREET-IN	D	138.00	13.09	
22	STEVENSVILLE-MI	D	69.00	13.00	
23	STONE LAKE-MI	D	69.00	13.00	
24		D	69.00	12.00	
25	STUBEY ROAD-MI	D	69.00	12.00	
26		D	69.00		
27	STUDEBAKER-IN	D	138.00	13.80	
28		D	138.00	13.09	
29	SULLIVAN (IM)-IN	T	765.00		
30		T	765.00	345.00	34.50
31		T	765.00	345.00	34.00
32		T	138.00		
33	SUMMIT-IN	D	138.00	13.09	
34	SWANSON-IN	D	69.00	34.00	
35		D	69.00		
36	TANNERS CREEK-IN	T	345.00	138.00	13.80
37	THOMAS ROAD-IN	D	69.00	13.09	
38	THREE M-IN	D	69.00	4.00	
39	THREE RIVERS (FTW)-IN	D	34.50	14.40	
40		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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
130	1					1
150	2					2
20	1					3
			STATCAP	1	53	4
12	1					5
20	1					6
20	1					7
30	1					8
20	1					9
20	1					10
20	1					11
11	1					12
8	1					13
12	1					14
200	2					15
22	1					16
			STATCAP	1	10	17
20	1					18
8	1					19
20	1					20
22	1					21
19	2					22
7	1					23
9	1					24
11	1					25
			STATCAP	1	14	26
36	2					27
20	1					28
			REACTOR	3	150	29
500	1					30
2500	5	1				31
			REACTOR	1	20	32
40	2					33
45	2					34
			STATCAP	1	14	35
450	1					36
20	1					37
13	1					38
22	2					39
10	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	THREE RIVERS (MBH)-MI	D	69.00	12.00	
2	TILLMAN-IN	T	138.00	36.20	
3	TILLOTSON-IN	D	34.50	13.00	
4	TRIER-IN	D	138.00	13.09	
5	TWENTY FIRST STREET-IN	D	34.50	13.00	
6	TWENTY THIRD STREET (IM)-IN	T	138.00	69.00	34.00
7		T	34.50		
8	TWIN BRANCH 138KV-IN	T	345.00	138.00	34.50
9		T	345.00	137.50	13.20
10		T	138.00	13.09	
11	TWIN BRANCH 34KV-IN	T	34.50	13.00	
12	UPLAND-IN	D	69.00	13.20	
13	UTICA (IM)-IN	D	34.50	13.09	
14	VALLEY-MI	T	138.00	69.00	34.00
15		T	138.00		
16		T	34.50		
17	VAN BUREN-IN	T	138.00	69.00	13.00
18	VICKSBURG-MI	D	69.00	13.09	
19		D	69.00	12.00	
20	WABASH AVENUE-IN	D	69.00	13.09	
21	WALLEN-IN	T	138.00	69.00	34.00
22		T	138.00	13.09	
23	WAYNE TRACE-IN	D	138.00	13.09	
24	WAYNEDALE-IN	D	138.00	13.09	
25		D	138.00	12.47	
26	WEBSTER-IN	D	34.50	14.00	
27		D	34.50	12.00	
28	WES-DEL-IN	D	138.00	13.09	
29	WEST END-IN	D	34.50	13.00	
30		D	34.50	4.00	
31	WEST SIDE-IN	T	138.00	69.00	34.00
32		T	138.00	13.09	
33		T	34.50		
34	WEST STREET-MI	D	138.00	13.09	
35	WHITAKER-IN	D	34.50	12.00	
36	WINCHESTER (IM)-IN	T	69.00	34.00	
37		T	69.00	13.00	
38		T	69.00		
39	WOODBURN-IN	D	69.00	13.00	
40					

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
22	1					1
18	1					2
20	1					3
20	1					4
19	2					5
213	2					6
			STATCAP	2	29	7
675	1					8
450	1					9
20	1					10
3	1					11
20	1					12
42	2					13
75	1					14
			STATCAP	1	44	15
			STATCAP	1	7	16
56	1					17
20	1					18
9	1					19
20	1					20
54	1					21
20	2					22
22	1					23
22	1					24
20	1					25
19	4					26
20	1					27
22	1					28
9	2					29
8	1					30
84	1					31
42	2					32
			STATCAP	1	12	33
20	1					34
20	1					35
17	1					36
26	2					37
			STATCAP	2	22	38
11	1					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 2013/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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	WOODS ROAD-IN	D	138.00	12.00	
2					
3	85 STATIONS UNDER 10 MVA	T/D			
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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 2013/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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
10	1					1
						2
381	91					3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

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 2013/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	AEPSC	920-935	12,308,164
3	Administrative and General Expenses	OPCO	920-931	1,185,300
4	AEP Support Services	AEPSC	403,417	1,133,111
5	Assets and Other Debits - Utility Plant	OPCO	107,108	386,650
6	Audit Services	AEPSC	920	1,399,841
7	Central Machine Shop	APCO	Various	2,450,507
8	Civic and Political Activities	AEPSC	426	705,590
9	Construction Services	AEPSC	107,108,120	31,114,058
10	Corporate Safety and Health	AEPSC	920	444,386
11	Corporate Accounting	AEPSC	920	3,556,567
12	Corporate Communication	AEPSC	920	890,047
13	Corporate Planning and Budgeting	AEPSC	920	1,931,073
14	Customer Accounts Expense	AEPSC	901-905	9,178,330
15	Customer and Distribution Services	AEPSC	920	355,756
16	Customer Service and Informational Expenses	AEPSC	907,908,910	324,308
17	Distribution Expenses - Maintenance	OPCO	592-598	351,911
18	Distribution Expenses - Operation	AEPSC	580-588	2,907,411
19	Emission Allowances Purchases	APCO	158	20,538,595
20	**Non-power Goods or Services Provided for Affiliate**			
21	Assets and Other Debits - Utility Plant	I&M Transmission Co	107,108	10,060,691
22	Assets and Other Debits - Utility Plant	OPCO	107,108	336,379
23	Barging	AEG	417	19,718,936
24	Barging	APCO	417	30,265,680
25	Barging	OPCO	417	40,089,470
26	Distribution Expenses - Maintenance	APCO	592-597	461,552
27	Fleet and Vehicle Charges	APCO	Various	1,097,967
28	Administrative and General - Operations	AEP River Ops	920,921	564,843
29	Fuel Handling	AEG	152	6,931,608
30	Material and Supplies	APCO	Various	759,935
31	Material and Supplies	OPCO	Various	5,721,337
32	Other Operating Revenues	APCO	456	280,977
33	Steam Power Generation - Maintenance	AEG	510-514	1,506,290
34	Steam Power Generation - Operation	AEG	500,505,506	4,508,760
35	Railcar Lease	PSO	151	595,411
36	Railcar Lease	SWEPCO	151	1,395,168
37	Customer Accounts Expense	AEPTC	903,904	259,485
38	Railcar Lease	OPCO	186	424,326
39	Barging	AEP River Ops	417	22,647,798
40	Building and Property Leases	AEPSC	454	1,204,861
41	Fleet and Vehicle Charges	AEPSC	Various	270,451
42	Materials and Supplies	IMTCo	107,570	1,590,890

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 2013/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	Distribution Expenses - Operation	OPCO	580-589	344,416
3	Environmental Services	AEPSC	920	435,282
4	Factored Customer A/R Bad Debts	AEP Credit	426	4,088,608
5	Factored Customer A/R Expense	AEP Credit	426	2,421,359
6	Coal Transloading	OPCO	151	15,595,717
7	Fleet and Vehicle Charges	APCO	Various	1,184,667
8	Fuel and Storeroom Services	AEPSC	151,152,163	4,445,229
9	Human Resources	AEPSC	920,923	3,103,092
10	Hydraulic Power Generation - Operation	AEPSC	535,537,539	1,034,106
11	Information Technology	AEPSC	920,923	5,598,838
12	Legal GC/Administration	AEPSC	920	4,011,769
13	Material and Supplies	APCO	Various	657,170
14	Treasury and Investor Relations	AEPSC	920	603,129
15	Material and Supplies	OPCO	Various	1,166,007
16	Nuclear Power Generation - Maintenance	AEPSC	528-532	2,429,105
17	Nuclear Power Generaion - Operation	AEPSC	517,524	1,471,574
18	Other Power Generation - Maintenance	AEPSC	553-557	5,122,982
19	Rail Car Lease	APCO	186	507,044
20	**Non-power Goods or Services Provided for Affiliate**			
21	Materials and Supplies	OHTCo	107	309,938
22	O&M Services for Rockport Plant	AEG	Various	26,241,327
23	Use of Jointly Owned Facilities	IMTCo	456	320,097
24	Urea Transloading	APCO	417	610,713
25	Urea Transloading	OPCO	417	472,767
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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	Transmission Expenses - Operaton	AEPSC	560-566	5,415,688
3	Rail Car Lease	SWEPCO	186	854,379
4	Rail Car Maintenance	SWEPCO	151	896,348
5	Real Estate and Workplace Services	AEPSC	920,923	970,470
6	Regulatory Services	AEPSC	920	2,702,305
7	Research and Other Services	AEPSC	183-188	3,853,435
8	Risk and Strategic Services	AEPSC	920	566,427
9	Steam Power Generation - Maintenance	AEPSC	510-514	2,975,759
10	Steam Power Generation - Operation	AEPSC	500-506	5,991,024
11	Rail Car Maintenance	OPCO	186	1,284,634
12	Transmission Expenses - Maintenance	AEPSC	568-573	1,552,859
13	Coal Transloading	AEG	151	10,794,478
14	Rail Car Maintenance	AEG	151	1,742,910
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Schedule Page: 429 Line No.: 6 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.: 7 Column: c

107,108,163,506,512,513,524,530,531,532,544,920

Schedule Page: 429 Line No.: 27 Column: b

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.: 30 Column: c

107,154,512,513,570,571,573,588,592

Schedule Page: 429 Line No.: 31 Column: c

107,108,154,163,511,512,513,514,570,571,588,592,593,594,935

Schedule Page: 429.1 Line No.: 13 Column: c

107,108,154,506,512,513,514,530,531,532,543,570,571,588,593,597,598,935

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

107,152,154,163,186,506,510,511,512,513,531,570,571,586,588,592,597,903,926,930,935