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, 2011

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: Bradley Funk **Title:** Manager of Regulated Accounting

Address: 1 Riverside Plaza

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

Telephone, Including Area Code: (614) 716-3162

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, 2012

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:

Regulated Energy 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, 2011
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 Bradley M. Funk	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) 716-3162	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 Andrew B. Reis	03 Signature  Andrew B. Reis	04 Date Signed (Mo, Da,Yr) April 24, 2012
02 Title Assistant Controller		

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, 2011

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	FERC Form 1
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
Statement of Retained Earnings for the Year		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
Construction Work in Progress - Electric	M	216	
Accumulated Provision for Depreciation of Electric Utility Plant		219	FERC Form 1
Nonutility Property	M	221	
Investment is Subsidiary Companies		224-225	FERC Form 1
Materials and Supply		227	FERC Form 1
Allowances		228 A/B-229 A/B	FERC Form 1
Extraordinary Property Losses		230B	NA
Unrecovered Plant and Regulatory Study Costs		230B	NA
Other Regulatory Assets		232	FERC Form 1
Miscellaneous Deferred Debits		233	FERC Form 1
Accumulated Deferred Income Taxes (Account 190)	M	234A-B	
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, 2011

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		255	
Long-Term Debt		256-257	FERC Form 1
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
Other Deferred Credits		269	FERC Form 1
Accumulated Deferred Income Taxes - Accelerated Amortization Property	M	272-273	FERC Form 1
Accumulated Deferred Income Taxes - Other Property	M	274-275	FERC Form 1
Accumulated Deferred Income Taxes - Other	M	276A-B	FERC Form 1
Other Regulatory Liabilities		278	FERC Form 1
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
Transmission of Electricity by Others		332	FERC Form 1
Miscellaneous General Expenses - Electric		335	FERC Form 1
Depreciation and Amortization of Electric Plant	M	337	FERC Form 1
Particulars Concerning Certain Income Deduction and Interest Charges Accounts	M	340	
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		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

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, 2011

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
ELECTRIC PLANT STATISTICAL DATA (Continued)		
Transmission Line Statistics	422-423	FERC Form 1
Transmission Lines Added During Year	424-425	FERC Form 1
Substations	426-427	FERC Form 1
Electric Distribution Meters and Line Transformers	429	
Environmental Protection Facilities	430	NA
Environmental Protection Expenses	431	NA
Footnote Data	450	
Stockholders' Report	---	
MPSC SCHEDULES		
Reconciliation of Deferred Income Tax Expense	117A-B	
Operating Loss Carry Forward	117C	NA
Plant Acquisition Adjustments and Accumulated Provision for Amortization of Plant Acquisition Adjustments	215	
Construction Work In Progress and Completed Construction Not Classified - Electric	216	
Construction Overheads - Electric	217	
General Description of Construction Overhead Procedure	218	
Accumulated Provision for Depreciation and Amortization of Nonutility Property	221	
Investments	222-223	
Notes & Accounts Receivable Summary for Balance Sheet	226A	
Accumulated Provision for Uncollectible Accounts - Credit	226A	
Receivables From Associated Companies	226B	
Production Fuel and Oil Stocks	227A-B	
Miscellaneous Current and Accrued Assets	230A	
Preliminary Survey and Investigation Charges	231A-B	NA
Deferred Losses from Disposition of Utility Plant	235A-B	NA
Unamortized Loss and Gain on Reacquired Debt	237A-B	
Securities Issued or Assumed and Securities Refunded or Retired During the Year	255	
Notes Payable	260A	NA
Payables to Associated Companies	260B	
Investment Tax Credits Generated and Utilized	264-265	
Miscellaneous Current and Accrued Liabilities	268	
Customer Advances for Construction	268	
Deferred Gains from Disposition of Utility Plant	270A-B	NA
Accumulated Deferred Income Taxes - Temporary	277	NA
Gain or Loss on Disposition of Property	280A-B	
Income from Utility Plant Leased to Others	281	NA
Particulars Concerning Certain Other Income Accounts	282	
Electric Operation and Maintenance Expenses (Nonmajor)	320N-324N	NA
Number of Electric Department Employees	234N	NA
Sales to Railroads & Railways and Interdepartmental Sales	331A	
Rent From Electric Property & Interdepartmental Rents	331A	
Sales of Water and Water Power	331B	
Misc. Service Revenues & Other Electric Revenues	331B	
Lease Rentals Charged	333A-D	
Expenditures for Certain Civic, Political and Related Activities	341	

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, 2011

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
MPSC SCHEDULES (Continued)		
Extraordinary Items	342	
Charges for Outside Professional and Other Consultative Services	357	
Summary of Costs Billed to Associated Companies	358-359	
Summary of Costs Billed from Associated Companies	360-361	
Monthly Transmission System Peak Load	400	NA
Changes Made or Scheduled to be Made in Generating Plant Capacities	412	
Steam-Electric Generating Plants	413A-B	
Hydroelectric Generating Plants	414-415	NA
Pumped Storage Generating Plants	416-418	NA
Internal Combustion Engine and Gas Turbine Generating Plants	420-421	NA
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 Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31,2011

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.

Andrew B. Reis, 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

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2011

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, 2011

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 C&I Company, LLC
AEP Coal, Inc.
AEP Credit, Inc.
AEP Fiber Venture, LLC
AEP Generating Company
AEP Investments, Inc.
AEP Nonutility Funding LLC
AEP Pro Serv, Inc.
AEP Resources, Inc.
AEP T&D Services, LLC
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 North Company
    AEP Texas North Generation Company LLC
  CSW Energy, Inc.
  CSW Energy Services, Inc.
  Electric Transmission Texas, LLC
AEP Utility Funding LLC
Appalachian Power Company
  Cedar Coal Co.
  Central Appalachian Coal Company
  Central Coal Company

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2011

CONTROL OVER RESPONDENT & OTHER ASSOCIATED COMPANIES

Southern Appalachian Coal Company
Franklin Real Estate Company
Indiana Michigan Power Company
Blackhawk Coal Company
Price River Coal Company
Kentucky Power Company
Kingsport Power Company
Ohio Power Company
AEP Generation Resources Inc.
Cardinal Operating Company
Central Coal Company
Conesville Coal Preparation Company
Distribution Vision 2010, LLC
OP Gavin, LLC
Ohio Valley Electric Corporation
Indiana-Kentucky Electric Corporation
Ohio Valley Electric Corporation
Indiana-Kentucky Electric Corporation
Power Tree Carbon Company, LLC
Public Service Company of Oklahoma
Southwestern Electric Power Company
Arkansas Coalition for Affordable & Reliable Electricity, LLC
Dolet Hills Lignite Company, LLC
Oxbow Lignite Company, LLC
Southwestern Arkansas Utilities Corporation
The Arklahoma Corporation
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 2011/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Price River Coal Company, Inc.	Coal Company - Inactive	100	
2	Blackhawk Coal Company, Inc.	Coal Company - Inactive	100	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2011

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	Michael G. Morris	1,305,480	1,500,000	A	9,186,906
	Chairman of the Board (resigned December 31, 2011)		89,746	B	
	Chief Executive Officer (resigned November 11, 2011)		5,313,000	C	
			978,680	D	
2	Brian X. Tierney	601,660	450,000	A	2,429,828
	Executive Vice President & Chief		32,683	B	
	Financial Officer		1,200,030	C	
			145,455	D	
3	Robert P. Powers	606,731	450,000	A	2,629,778
	Executive Vice President & Chief		46,135	B	
	Operating Officer		1,123,168	C	
			403,744	D	
4	Nicholas K. Akins	770,192	750,000	A	2,807,802
	President & Chief Executive Officer		40,362	B	
	Appointed November 12, 2011		1,123,168	C	
			124,080	D	
5	Carl L. English	575,000	421,571	A	2,660,645
	Former Vice Chairman		32,919	B	
	Retired December 31, 2011		1,500,037	C	
			131,118	D	
6	D. Michael Miller	410,000	260,515	A	2,157,973
	Former Senior Vice President &		26,637	B	
	General Counsel		900,022	C	
	Retired December 31, 2011		560,799	D	
7	Susan Tomasky	302,885	214,219	A	3,055,221
	Former President AEP Transmission		27,226	B	
	Retired July 31, 2011		999,907	C	
			1,510,984	D	

Compensation Type Codes:

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

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31,2011

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 - Vice President *** Chief Executive Officer	Columbus, Ohio	11	0
Carl L. English - Vice President ***	Columbus, Ohio	12	0
Allen R. Glassburn	Fort Wayne, Indiana	0	0
Marc E. Lewis - Vice President External Affairs	Fort Wayne, Indiana	0	0
Michael G. Morris - Chairman of Board, Chief Executive Officer **	Columbus, Ohio	8	0
Robert P. Powers***	Columbus, Ohio	12	0
Susan Tomasky - Vice President ***	Columbus, Ohio	6	0
Brian X. Tierney - Vice President *** - Chief Financial Officer	Columbus, Ohio	11	0

Footnote Data

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Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31,2011

DIRECTORS (cont'd)

Name and Title of Director (a)	Principal Business Address (b)	# of Directors Meetings During Yr (c)	Fees During Yr (d)
J. Edward Ehler - Vice President Distribution Region Operations	Fort Wayne, Indiana	0	0
Scott M. Krawec	Fort Wayne, Indiana	0	0
Sarah L. Bodner	Fort Wayne, Indiana	0	0
Paul Chodak, III - President & COO	Fort Wayne, Indiana	0	0
Daniel V. Lee - VP - Generation Assets	Fort Wayne, Indiana	0	0
Lisa M. Barton - Vice President ***	Columbus, Ohio	3	0

Footnote Data

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2011

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 26, 2011 in Columbus, Ohio

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Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A resubmission		December 31, 2011

SECURITY HOLDERS AND VOTING POWERS (Continued)

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

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 2011/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.

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SEE PAGE 109 FOR REQUIRED INFORMATION.

1.

Date Acquired Or Extended	Community	Period of Franchise & Termination	Consideration
Renewed on March 7, 2011	Cheshire Township, Allegan County, MI	Thirty (30) year Franchise renewal expiring on March 7, 2041	None
Renewed on February 14, 2011	Pavilion Township, Kalamazoo County, MI	Thirty (30) year Franchise renewal expiring on February 14, 2041	None
Renewed on April 13, 2011	Almena Township, Van Buren County, MI	Thirty (30) year Franchise renewal expiring on May 13, 2041	None
Renewed on April 18, 2011	Milton Township, Cass County, MI	Ten (10) year Franchise renewal expiring on June 17, 2021	None
Renewed on April 18, 2011	Sherman Township, St. Joseph County, MI	Thirty (30) year Franchise renewal expiring on April 28, 2041	None
Renewed on April 19, 2011	Columbia Township, Van Buren County, MI	Thirty (30) year Franchise renewal expiring on April 25, 2041	None
Renewed on May 5, 2011	Lawrence Village, Van Buren County, MI	Thirty (30) year Franchise renewal expiring on May 10, 2041	None
Renewed on August 16, 2011	City of Gobles, Van Buren County, MI	Thirty (30) year Franchise renewal expiring on August 27, 2041	None
Renewed on November 11, 2011	Village of Mattawan, Van Buren County, MI	Thirty (30) year Franchise renewal expiring on November 11, 2041	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. ES10-1-000)

   Reoffering of $52.0M City of Lawrenceburg, Indiana Pollution Control Revenue Refunding

Bonds (Indiana Michigan Power Company Project), Series H due November 1, 2021

Reoffering of $25.0M City of Lawrenceburg, Indiana Pollution Control Revenue Refunding Bonds (Indiana Michigan Power Company Project), Series I due October 1, 2019

$109.975M fuel capital lease (State Commission Authority, Cause No. 44025)

7. None

8. Employees represented by UWUA Local #418 were provided with a 3% general wage increase effective February 16, 2011

   Employees represented by United Steel Workers Local #13729 were provided with a 3% general wage increase effective December 1, 2011

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

10. None

11. (Reserved)

12. Not Used

13. Susan Tomasky resigned as Director and Vice President effective July 31, 2011
    Mark K. Knoy resigned as Vice President effective August 1, 2011
    Lisa M. Barton appointed as Director and Vice President effective August 1, 2011
    Keith M. Darling appointed Vice President August 2, 2011
    Nicholas K. Akins appointed as Chief Executive Officer effective November 12, 2011
    Michael G. Morris resigned as Chief Executive Officer effective November 11, 2011
    Carl L. English resigned as Director and Vice President effective December 31, 2011
    D. Michael Miller resigned as Secretary effective December 31, 2011
    Michael G. Morris resigned as Director and Chairman of the Board effective December 31, 2011

    Subsequent Information:
    Nicholas K. Akins appointed as Chairman of the Board effective January 1, 2012
    David M. Feinberg appointed as Secretary and Director effective January 1, 2012
    Mark C. McCullough appointed as Director effective January 1, 2012

14. Proprietary capital ratio exceeds 30%

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	6,884,397,631	6,611,261,964
3	Construction Work in Progress (107)	200-201	236,095,869	301,533,558
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		7,120,493,500	6,912,795,522
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	3,424,425,300	3,367,993,001
6	Net Utility Plant (Enter Total of line 4 less 5)		3,696,068,200	3,544,802,521
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	97,708,873	93,706,590
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		124,839,783	180,310,269
10	Spent Nuclear Fuel (120.4)		255,621,386	261,667,212
11	Nuclear Fuel Under Capital Leases (120.6)		188,705,956	175,474,706
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	362,124,415	384,155,662
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		304,751,583	327,003,115
14	Net Utility Plant (Enter Total of lines 6 and 13)		4,000,819,783	3,871,805,636
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		29,276,858	26,802,369
19	(Less) Accum. Prov. for Depr. and Amort. (122)		14,149,385	12,348,149
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	23,490,770	23,808,747
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	7,848,512	12,430,034
24	Other Investments (124)		22,793,024	22,922,468
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		1,591,731,686	1,515,226,729
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		29,345,323	31,477,566
31	Long-Term Portion of Derivative Assets – Hedges (176)		16,746	7,149
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		1,690,353,534	1,620,326,913
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		1,013,372	354,667
36	Special Deposits (132-134)		10,318,361	15,488,029
37	Working Fund (135)		6,300	6,300
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		72,346,209	76,092,138
41	Other Accounts Receivable (143)		18,250,490	9,959,551
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,749,514	1,692,114
43	Notes Receivable from Associated Companies (145)		90,442,321	0
44	Accounts Receivable from Assoc. Companies (146)		88,552,840	146,858,216
45	Fuel Stock (151)	227	51,129,732	85,318,798
46	Fuel Stock Expenses Undistributed (152)	227	1,849,711	2,232,093
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	146,238,660	148,499,563
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	3,057,394	3,256,501
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	34,476,260	39,005,421

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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		7,848,512	12,430,034
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)		6,883,077	8,358,762
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		7,152,974	4,448,582
60	Rents Receivable (172)		114,584	99,578
61	Accrued Utility Revenues (173)		14,779,580	19,449,455
62	Miscellaneous Current and Accrued Assets (174)		72,975,502	49,022,092
63	Derivative Instrument Assets (175)		61,237,360	58,834,598
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		29,345,323	31,477,566
65	Derivative Instrument Assets - Hedges (176)		276,554	175,626
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		16,746	7,149
67	Total Current and Accrued Assets (Lines 34 through 66)		642,141,186	621,853,107
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		9,882,271	11,679,904
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	630,142,964	585,007,876
73	Prelim. Survey and Investigation Charges (Electric) (183)		95,664	1,006,697
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	38,328,279	36,269,154
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)		15,078,694	16,023,450
82	Accumulated Deferred Income Taxes (190)	234	774,052,033	745,790,961
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,467,579,905	1,395,778,042
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		7,800,894,408	7,509,763,698

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2011/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	8,072,400
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	4,317,820
7	Other Paid-In Capital (208-211)	253	976,661,804	976,975,945
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	751,952,003	677,547,416
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-230,765	-189,146
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)	-28,221,410	-20,888,248
16	Total Proprietary Capital (lines 2 through 15)		1,760,980,133	1,702,420,053
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	1,827,992,520	1,806,900,748
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		4,907,418	5,428,173
24	Total Long-Term Debt (lines 18 through 23)		1,823,085,102	1,801,472,575
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		140,888,065	138,956,461
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		74,898	96,882
29	Accumulated Provision for Pensions and Benefits (228.3)		181,037,980	194,625,175
30	Accumulated Miscellaneous Operating Provisions (228.4)		4,516,050	3,466,050
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		8,050,831	6,530,257
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		10,820,041	178
34	Asset Retirement Obligations (230)		1,013,121,583	963,028,567
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,358,509,448	1,306,703,570
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		113,062,717	121,664,515
39	Notes Payable to Associated Companies (233)		0	48,104,996
40	Accounts Payable to Associated Companies (234)		81,153,568	105,256,398
41	Customer Deposits (235)		30,695,644	29,263,723
42	Taxes Accrued (236)	262-263	39,814,135	8,848,773
43	Interest Accrued (237)		29,444,022	29,359,527
44	Dividends Declared (238)		0	84,810
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 2011/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)		6,480,745	6,693,078
48	Miscellaneous Current and Accrued Liabilities (242)		140,691,691	112,454,834
49	Obligations Under Capital Leases-Current (243)		78,519,767	69,745,948
50	Derivative Instrument Liabilities (244)		23,691,329	22,878,420
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		8,050,831	6,530,257
52	Derivative Instrument Liabilities - Hedges (245)		12,159,717	437,083
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		10,820,041	178
54	Total Current and Accrued Liabilities (lines 37 through 53)		536,842,463	548,261,670
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	52,632,906	55,416,298
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	62,469,260	92,249,858
60	Other Regulatory Liabilities (254)	278	493,685,208	475,483,908
61	Unamortized Gain on Reaquired Debt (257)		20,115	21,827
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	262,768	283,301
63	Accum. Deferred Income Taxes-Other Property (282)		867,361,701	777,228,742
64	Accum. Deferred Income Taxes-Other (283)		845,045,304	750,221,896
65	Total Deferred Credits (lines 56 through 64)		2,321,477,262	2,150,905,830
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		7,800,894,408	7,509,763,698

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Company	(2) [ ] A Resubmission		December 31, 2011

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)
110	5	c	MPSC adopted the FERC Uniform System of Accounts for electric utilities in Case No. U-14811. In previous years, the MPSC permitted I&M to record decommissioning expense in conformance with FERC Uniform System of Accounts for general ledger purposes, but required I&M to reclass the Michigan portion of this expense from account 524 to account 403 for Michigan reporting purposes. I&M has restated the amount for the previous year to reflect the adoption of FERC Uniform System of accounts.
112	34	c	MPSC adopted the FERC Uniform System of Accounts for electric utilities in Case No. U-14811. In previous years, the MPSC permitted I&M to record decommissioning expense in conformance with FERC Uniform System of Accounts for general ledger purposes, but required I&M to reclass the Michigan portion of this expense from account 524 to account 403 for Michigan reporting purposes. I&M has restated the amount for the previous year to reflect the adoption of FERC Uniform System of accounts.
112	60	c	MPSC adopted the FERC Uniform System of Accounts for electric utilities in Case No. U-14811. In previous years, the MPSC permitted I&M to record decommissioning expense in conformance with FERC Uniform System of Accounts for general ledger purposes, but required I&M to reclass the Michigan portion of this expense from account 524 to account 403 for Michigan reporting purposes. I&M has restated the amount for the previous year to reflect the adoption of FERC Uniform System of accounts.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	2,128,984,087	2,157,506,760		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,391,932,163	1,440,290,037		
5	Maintenance Expenses (402)	320-323	229,883,100	222,405,724		
6	Depreciation Expense (403)	336-337	108,272,070	103,905,672		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	3,976,605	3,778,471		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	19,172,994	27,734,887		
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)		1,972,806	1,024,171		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	77,862,981	73,606,278		
15	Income Taxes - Federal (409.1)	262-263	-76,271,102	-900,499		
16	- Other (409.1)	262-263	-2,709,590	5,390,839		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	443,210,765	396,695,300		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	307,429,077	335,878,212		
19	Investment Tax Credit Adj. - Net (411.4)	266	-2,783,392	-2,315,843		
20	(Less) Gains from Disp. of Utility Plant (411.6)		142,074	105,085		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		3,484	51,012		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		11,667,707	11,905,037		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,898,612,472	1,947,485,765		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		230,371,615	210,020,995		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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
2,128,984,087	2,157,506,760					2
						3
1,391,932,163	1,440,290,037					4
229,883,100	222,405,724					5
108,272,070	103,905,672					6
3,976,605	3,778,471					7
19,172,994	27,734,887					8
						9
						10
						11
1,972,806	1,024,171					12
						13
77,862,981	73,606,278					14
-76,271,102	-900,499					15
-2,709,590	5,390,839					16
443,210,765	396,695,300					17
307,429,077	335,878,212					18
-2,783,392	-2,315,843					19
142,074	105,085					20
						21
3,484	51,012					22
						23
11,667,707	11,905,037					24
1,898,612,472	1,947,485,765					25
230,371,615	210,020,995					26

Name of Respondent: Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr): / /	Year/Period of Report: End of 2011/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)		230,371,615	210,020,995		
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)		121,007,840	124,489,320		
34	(Less) Expenses of Nonutility Operations (417.1)		113,709,695	115,718,577		
35	Nonoperating Rental Income (418)		217,495	228,010		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-41,619	392,185		
37	Interest and Dividend Income (419)		2,947,054	1,396,458		
38	Allowance for Other Funds Used During Construction (419.1)		15,395,278	15,678,344		
39	Miscellaneous Nonoperating Income (421)		-514,407	3,665,157		
40	Gain on Disposition of Property (421.1)		988,254	1,947,709		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		26,290,200	32,078,606		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		82,538	39,377		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		2,026,494	1,796,509		
46	Life Insurance (426.2)					
47	Penalties (426.3)		26,853	-438,082		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,178,933	1,018,577		
49	Other Deductions (426.5)		10,636,924	8,473,402		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		13,951,742	10,889,783		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	4,410,520	6,798,291		
53	Income Taxes-Federal (409.2)	262-263	-1,679,422	-2,807,236		
54	Income Taxes-Other (409.2)	262-263	245,654	83,975		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	7,620,935	11,106,119		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	8,577,249	8,200,192		
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)		2,020,438	6,980,957		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		10,318,020	14,207,866		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		92,125,153	99,830,716		
63	Amort. of Debt Disc. and Expense (428)		2,222,601	3,103,138		
64	Amortization of Loss on Reaquired Debt (428.1)		1,548,025	1,399,579		
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)		24,245	296,045		
68	Other Interest Expense (431)		2,935,674	2,010,170		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		7,838,235	8,499,589		
70	Net Interest Charges (Total of lines 62 thru 69)		91,015,751	98,138,347		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		149,673,884	126,090,514		
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)		149,673,884	126,090,514		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Company	(2) [ ] A Resubmission		December 31, 2011

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)
114	4	c	MPSC adopted the FERC Uniform System of Accounts for electric utilities in Case No. U-14811. In previous years, the MPSC permitted I&M to record decommissioning expense in conformance with FERC Uniform System of Accounts for general ledger purposes, but required I&M to reclass the Michigan portion of this expense from account 524 to account 403 for Michigan reporting purposes. I&M has restated the amount for the previous year to reflect the adoption of FERC Uniform System of accounts.
114	6	c	MPSC adopted the FERC Uniform System of Accounts for electric utilities in Case No. U-14811. In previous years, the MPSC permitted I&M to record decommissioning expense in conformance with FERC Uniform System of Accounts for general ledger purposes, but required I&M to reclass the Michigan portion of this expense from account 524 to account 403 for Michigan reporting purposes. I&M has restated the amount for the previous year to reflect the adoption of FERC Uniform System of accounts.

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, 2011

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	122,793,545	
3	Account 281	0	
4	Account 282	129,614,468	
5	Account 283	190,802,752	
6	Account 284		
7	Reconciling Adjustments		
8	TOTAL Account 410.1 (on pages 114-115 line 17)	**443,210,765**	**0**
9	TOTAL Account 410.2 (on page 117 line 55)		
10	Credits to Account 411 from:		
11	Account 190	135,547,841	
12	Account 281	20,533	
13	Account 282	39,030,943	
14	Account 283	132,829,760	
15	Account 284		
16	Reconciling Adjustments		
17	TOTAL Account 411.1 (on page 114-115 line 18)	**307,429,077**	**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	(2,783,392)	
22	ITC Adjustments:		
23	Adjust last year's estimate to actual per filed return		
24	Other (specify)		
25	Net Reconciling Adjustments Account 411.4*	**(2,783,392)**	**0**
26	Net Reconciling Adjustments Account 411.5**		
27	Net Reconciling Adjustments Account 420***		

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, 2011

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
	122,793,545	4,334,691	127,128,236	2
	0		0	3
	129,614,468	29,712	129,644,180	4
	190,802,752	3,256,532	194,059,284	5
				6
				7
0	**443,210,765**			8
		7,620,935		9
				10
	135,547,841	5,520,779	141,068,620	11
	20,533		20,533	12
	39,030,943	1,290	39,032,233	13
	132,829,760	3,055,180	135,884,940	14
				15
				16
0	**307,429,077**			17
		8,577,249		18
				19
				20
	(2,783,392)		(2,783,392)	21
				22
				23
				24
0	(2,783,392)	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 2011/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		675,141,591	655,362,847
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6	Reclassification of balance in Acct 2160002 to 2160001	2160002		(5,900,000)
7		2160001		5,900,000
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)		149,715,503	125,698,329
17	Appropriations of Retained Earnings (Acct. 436)			
18	Reclassification of Appropriated Retained Earnings-Amort. Reserve-Federal	215.1	-265,394	(580,242)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-265,394	(580,242)
23	Dividends Declared-Preferred Stock (Account 437)			
24	Preferred Stock Series 4-1/8%	238	-208,927	(228,077)
25	Preferred Stock Series 4.12%	238	-41,749	(45,547)
26	Preferred Stock Series 4.56%	238	-60,240	(65,719)
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-310,916	(339,343)
30	Dividends Declared-Common Stock (Account 438)			
31	Dividends Declared - Common Stock	238	-75,000,000	(105,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-75,000,000	(105,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		749,280,784	675,141,591
	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 2011/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)		2,671,219	2,405,825
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		2,671,219	2,405,825
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		751,952,003	677,547,416
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-189,146	(581,331)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-41,619	392,185
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		-230,765	(189,146)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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)	149,673,884	126,090,514
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	131,421,669	135,419,030
5	Amortization of Regulatory Debits and Credits (Net)	1,972,806	1,024,171
6	Amortization of Nuclear Fuel	143,343,197	146,343,318
7	Accretion of Asset Retirement Obligations	11,667,707	11,905,037
8	Deferred Income Taxes (Net)	134,825,374	63,723,015
9	Investment Tax Credit Adjustment (Net)	-2,783,392	-2,315,843
10	Net (Increase) Decrease in Receivables	51,272,794	-79,062,449
11	Net (Increase) Decrease in Inventory	37,031,458	-14,430,369
12	Net (Increase) Decrease in Allowances Inventory	4,529,161	-2,133,958
13	Net Increase (Decrease) in Payables and Accrued Expenses	-25,350,259	123,983,445
14	Net (Increase) Decrease in Other Regulatory Assets	13,622,411	-38,320,424
15	Net Increase (Decrease) in Other Regulatory Liabilities	-12,910,922	-11,482,824
16	(Less) Allowance for Other Funds Used During Construction	15,395,278	15,678,344
17	(Less) Undistributed Earnings from Subsidiary Companies	-41,619	392,185
18	Other (provide details in footnote):	-52,070,367	-35,225,021
19	Mark-to-Market of Risk Management Contracts	-1,589,853	4,592,423
20	Pension Contributions to Qualified Plant Trust	-52,582,000	-71,671,611
21	Deferred Cook Fire Costs, net of Insurance Proceeds	18,282,259	87,347,299
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	535,002,268	429,715,224
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-308,637,096	-355,149,793
27	Gross Additions to Nuclear Fuel	-113,682,836	-98,233,319
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-20,322	-756,176
30	(Less) Allowance for Other Funds Used During Construction	-15,395,278	-15,678,344
31	Acquired Assets	-1,171,607	-3,985,528
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-408,116,583	-442,446,472
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	35,650,306	21,076,985
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)	-1,166,690,088	-1,414,472,681
45	Proceeds from Sales of Investment Securities (a)	1,110,909,126	1,361,812,957

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	142	13,034
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other	12,687,473	14,320,647
54	(Increase)/Decrease in Other Special Deposits	3,172	13,047
55	Notes Receivable from Associated Companies	-90,442,321	108,851,089
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-505,998,773	-350,831,394
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	77,000,000	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Long Term Issuance Costs	-1,002,858	
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):	110,050,506	152,936,213
68	Notes Payable to Associated Companies		48,104,996
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	186,047,648	201,041,209
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-82,506,799	-175,000,000
74	Preferred Stock	-8,469,727	-3,358
75	Common Stock		
76	Other (provide details in footnote):		
77	Notes Payable to Associated Companies	-48,104,996	
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock	-310,916	-339,343
81	Dividends on Common Stock	-75,000,000	-105,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-28,344,790	-79,301,492
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	658,705	-417,662
87			
88	Cash and Cash Equivalents at Beginning of Period	360,967	778,629
89			
90	Cash and Cash Equivalents at End of period	1,019,672	360,967

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

	2011 Cash Flow Incr/Decr	2010 Cash Flow Incr/Decr
Utility Plant, Net	(132,694,756)	(111,022,306)
Property and Investments, Net	(306,057)	437,088
Margin Deposits	5,166,496	(453,348)
Prepayments	16,650,684	21,131,803
Accrued Utility Revenues, Net	4,669,875	(10,687,211)
Miscellaneous Current and Accr Assets	(2,412,637)	2,800,000
Unamortized Debt Expense	2,326,306	1,883,133
Other Deferred Debits, Net	(1,643,764)	(554,167)
Other Comprehensive Income, Net	5,022,437	673,996
Unamortized Discount/Premium on LTD	520,755	520,755
Accumulated Provisions - Misc	1,461,735	1,411,193
Current and Accrued Liabilities, Net	23,916,331	15,102,379
Other Deferred Credits, Net	25,252,228	43,531,664
Total	(52,070,367)	(35,225,021)

Schedule Page: 120 Line No.: 31 Column: b

	2011 Cash Flow Incr/Decr	2010 Cash Flow Incr/Decr
Barge Purchase for Resale	-	(1,349,528)
Master Lease Agreement	(160,061)	(1,782,933)
Railcar Purchases from JP Morgan	-	(853,067)
Acquired Assets from Transco	(1,156,000)	-
Deferred Lease Assets	144,454	-
Total	(1,171,607)	(3,985,528)

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

	2011	2010
Transformer Sales - Affiliated Companies	217,233	492,899
Meter Sales - Affiliated Companies	224,151	202,057
Rotor Sales - Affiliated Companies	-	794,694
Barge Sales - Affiliated Companies	-	135,000
Substation Sales - Non-Affiliated Companies	-	167,046
Equipment Sales - Non-Affiliated Companies	-	495,431
Towboat/Barge Sales - Non-Affiliated Companies	33,152,584	16,939,782
Land Sale - 6.999 Acres to Indiana Dept of Transportation	-	113,600
Land Sale - 13.16 Acres to City of Mishawaka	191,517	-
Sale of Bluff Point Wind Project	1,600,569	-
Railcar Sales - Non-Affiliated Companies	-	828,400
Royal Bank of Scotland Operating Lease	264,252	908,076
Total	35,650,306	21,076,985

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

	2011	2010
Cook Fire Utility Plant Property Insurance	-	14,320,647
Rockport Ductwork Insurance Proceeds	1,520,009	-
Department of Energy Proceeds	11,167,464	-

Total	12,687,473	14,320,647

Schedule Page: 120 Line No.: 67 Column: b

	2011	2010
Proceeds on Nuclear Fuel Sale/Leaseback	109,975,000	152,464,063
Proceeds on Capital Leaseback	75,506	472,150
Total	110,050,506	152,936,213

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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				(11,802,691)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				520,827
3	Preceding Quarter/Year to Date Changes in Fair Value				(919,896)
4	Total (lines 2 and 3)				(399,069)
5	Balance of Account 219 at End of Preceding Quarter/Year				(12,201,760)
6	Balance of Account 219 at Beginning of Current Year				(12,201,760)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				552,794
8	Current Quarter/Year to Date Changes in Fair Value				(1,286,687)
9	Total (lines 7 and 8)				(733,893)
10	Balance of Account 219 at End of Current Quarter/Year				(12,935,653)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	(9,513,932)	(383,881)	(21,700,504)		
2	1,006,918	1,105,407	2,633,152		
3		(901,000)	(1,820,896)		
4	1,006,918	204,407	812,256	126,090,514	126,902,770
5	(8,507,014)	(179,474)	(20,888,248)		
6	(8,507,014)	(179,474)	(20,888,248)		
7	955,479	652,574	2,160,847		
8	(6,913,864)	(1,293,458)	(9,494,009)		
9	(5,958,385)	(640,884)	(7,333,162)	149,673,884	142,340,722
10	(14,465,399)	(820,358)	(28,221,410)		

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 2011/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.

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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. Rate Matters
3. Effects of Regulation
4. Commitments, Guarantees and Contingencies
5. Benefit Plans
6. Business Segments
7. Derivatives and Hedging
8. Fair Value Measurements
9. Income Taxes
10. Leases
11. Financing Activities
12. Related Party Transactions
13. Property, Plant and Equipment
14. Cost Reduction Initiatives

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., a holding company.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East companies	APCo, I&M, KPCo and OPCo.
AEP Power Pool	Members are APCo, I&M, KPCo and OPCo. The AEP Power Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.

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
AEP West companies	PSO, SWEPCo, TCC and TNC.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
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.
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.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW 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.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC and DCC Fuel IV LLC, entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
FAC	Fuel Adjustment Clause.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
kV	Kilovolt.
KWH	Kilowatthour.
MISO	Midwest Independent Transmission System Operator.

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 AEP Power Pool transactions to its members.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NEIL	Nuclear Electric Insurance Limited insures domestic and international nuclear utilities for the costs associated with interruptions, damages, decontaminations and related nuclear risks.
NO_X	Nitrogen oxide.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
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 generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M.
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	AEP System's Utility Money Pool is the centralized funding mechanism AEP uses to meet the short term cash requirements of pool participants.
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 582,000 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 (RTD) provides barging services to affiliates and nonaffiliated companies.

The Interconnection Agreement establishes the AEP Power Pool which permits the AEP East companies to pool their generation assets on a cost basis. It establishes 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. AEP Power Pool members are compensated for their costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. The AEP Power Pool calculates 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 is the MLR, which determines each member's percentage share of revenues and costs. APCo's Dresden Plant was completed in January 2012. The addition of the Dresden Plant and removal of OPCo's Sporn Unit 5 will change the capacity reserve relationship of the AEP Power Pool members.

The AEP East companies are parties to a Transmission Agreement defining how they share the revenues and costs associated with their relative ownership of transmission assets. This sharing was based upon each company's MLR until the FERC approved a new Transmission Agreement effective November 1, 2010. The new Transmission Agreement will be phased-in for retail rates over periods of up to four years, adds KGPCo and WPCo as parties to the agreement and changes the allocation method. I&M's recovery mechanism for transmission costs is through its base rates. Changes in allocation under the new Transmission Agreement and state regulatory phase-in of the new agreement will limit I&M's ability to fully recover its transmission costs.

Under unit power agreements, I&M purchases AEGCo's 50% share of the 2,600 MW Rockport Plant capacity unless it is sold to other utilities. AEGCo is an affiliate that is not a member of the AEP Power Pool. An agreement between AEGCo and KPCo provides for the sale of 390 MW of AEGCo's Rockport Plant capacity to KPCo through 2022. Therefore, 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 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.

AEPSC conducts power, gas, coal and emission allowance risk management activities on I&M's behalf. I&M shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the other AEP East companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the existing power pool agreement and the SIA. I&M shares in coal and emission allowance 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 gas, coal and emission allowances. The electricity, gas, coal and emission allowance 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.

To minimize the credit requirements and operating constraints when operating within PJM, the AEP East companies as well as KGPCo and WPCo, agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due to the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

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

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

I&M is subject to regulation by the FERC under the Federal Power Act and the Energy Policy Act of 2005 and maintains accounts in accordance with the FERC and other regulatory guidelines. I&M's rates are regulated by the FERC, the IURC and the MPSC. The FERC also regulates I&M's affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities, 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 that a nonregulated affiliate can bill an affiliated public utility company 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. Although I&M's retail transmission rates in Michigan are unbundled, retail transmission rates are regulated, on a cost basis, by the MPSC. In Indiana, bundled retail transmission rates are regulated, on a cost basis, by the IURC.

In addition, the FERC regulates the SIA, the Interconnection Agreement, the CSW Operating Agreement, the System Transmission Integration Agreement, the Transmission Agreement, the Transmission Coordination Agreement and the AEP System Interim Allowance Agreement, all of which allocate shared system costs and revenues to the companies 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 tax assets related to the accounting guidance for "Uncertainty in Income Taxes" as a reduction to current liabilities rather than a tax benefit.
- The classification of noncurrent tax liabilities related to the accounting guidance for "Uncertainty in Income Taxes" as a current liability rather than a noncurrent liability.
- The classification of regulatory assets and liabilities related to the accounting guidance for "Accounting for Income Taxes" as separate assets and liabilities rather than as a single amount.
- The presentation of 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 fuel expense.
- The classification of certain nonoperating revenues as miscellaneous nonoperating income instead of as operating revenue.
- The separate classification of income tax expense on Net Utility Operating Income and on Net Other Income and Deductions instead of as a single net income tax.
- 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 interest receivable and interest accrued related to federal income tax and state income tax balances as separate current assets and current liabilities rather than as a single net amount.
- The classification of unamortized loss on reacquired debt in deferred debits rather than in regulatory assets.
- The classification of accumulated deferred investment tax credits in deferred credits rather than in regulatory liabilities and deferred investment tax credits.
- The classification of certain other assets and liabilities as current instead of noncurrent.
- The classification of certain other assets and liabilities as noncurrent instead of current.

Accounting for the Effects of Cost-Based Regulation

As rate-regulated electric public utility companies, 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 (future revenue reductions or refunds) to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues.

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

	2011	2010
For the Years Ended December 31,	**(in thousands)**	
Cash was Paid (Received) for:		
Interest (Net of Capitalized Amounts)	$ 88,492	$ 93,715
Income Taxes (Net of Refunds)	(96,524)	(71,433)
Noncash Acquisitions Under Capital Leases	113,429	162,464
At December 31,		
Construction Expenditures Included in Current and Accrued Liabilities	42,992	21,757
Acquisition of Nuclear Fuel Included in Accounts Payable	715	308
Noncash Increase in Long-term Debt Through the Fort Wayne Lease Settlement	26,802	-

Special Deposits

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

Inventory

Fossil fuel inventories are generally carried at average cost. 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, 2011.

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. I&M follows the inventory model for allowances. Allowances are consumed in the production of energy and are recorded in Operation Expenses at an average cost. Allowances held for speculation are included in Other Investments. Gains or losses on sales of emission allowances held speculatively are recorded in Miscellaneous Nonoperating Income and Other Deductions, respectively. Purchases and sales of allowances are reported in the Operating Activities section of the statements of cash flows except speculative allowance transactions which are reported in Investing Activities.

Property, Plant and Equipment

Electric utility property, plant and equipment for rate-regulated operations are stated at original purchase cost. Additions, major replacements and betterments are added to the plant accounts. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation under the group composite method of 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. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. 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 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.

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 non-binding 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 and 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. Long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3.

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 equivalents 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 fuel cost disallowance becomes probable, I&M adjusts its FAC deferrals and records a provision for estimated refunds to recognize these probable outcomes.

Changes in fuel costs, including purchased power in Indiana and Michigan are reflected in rates in a timely manner through the FAC. 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 (all areas of Michigan beginning in December 2010).

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.

Traditional 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 RTO operating in the east service territory. The AEP East companies purchase power from PJM to supply power to their customers. These power sales and purchases are reported on an hourly net basis. In hours where the AEP East companies are required to purchase more power than they sold into PJM to cover retail and wholesale customer obligations, I&M's share of these amounts is reported in Operation Expenses. In hours where the AEP East companies sell more power than they purchased from PJM to cover retail and wholesale customer obligations, I&M's share of these amounts is reported in Operating Revenues. 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 on the statements of income. 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 on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, I&M records expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting. 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 electricity, coal, natural gas and emission allowances 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 and the buying and selling of financial energy contracts which include exchange traded futures and options, as well as OTC options and swaps. 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 7.

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 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 agents 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 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	45.0 %
Fixed Income	45.0 %
Other Investments	10.0 %

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. Investment policies prohibit the benefit trust funds from purchasing 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 one issuer
- 5% private placements
- 5% 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 classified as Level 1.

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 eleven 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. 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 equity and debt 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 gains or losses 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 4 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 8 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. 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.

Michigan 2009 and 2010 Power Supply Cost Recovery (PSCR) Reconciliation (Cook Plant Unit 1 Fire and Shutdown)

In March 2010, I&M filed its 2009 PSCR reconciliation with the MPSC. The filing included an adjustment to exclude from the PSCR the incremental fuel cost of replacement power due to the Cook Plant Unit 1 (Unit 1) outage from mid-December 2008 through December 2009, the period during which I&M received and recognized accidental outage insurance proceeds. In October 2010, a settlement agreement was filed with the MPSC which included deferring the Unit 1 outage issue to the 2010 PSCR reconciliation. In November 2011, the MPSC approved a settlement agreement for the 2010 PSCR reconciliation which resolved the Unit 1 outage issue by ordering no disallowances associated with the Unit 1 outage issue. See the "Cook Plant Unit 1 Fire and Shutdown" section of Note 4.

2011 Michigan Base Rate Case

In July 2011, I&M filed a request with the MPSC for an annual increase in Michigan base rates of $25 million and a return on common equity of 11.15%. The request included an increase in depreciation rates that would result in a $6 million increase in annual depreciation expense. An interim rate increase of $16 million annually was implemented in January 2012, subject to refund.

In February 2012, the MPSC approved a settlement agreement which increased annual base rates by approximately $15 million, effective April 2012, based upon a return on common equity of 10.2% and included a $5 million annual increase in depreciation rates. The approved settlement agreement also excluded the Michigan jurisdictional share of the net costs of the Cook Plant Unit 1 (Unit 1) turbine replacement from rate base but provided for a return on and of the net cost as a regulatory asset, effective February 2012. As of December 31, 2011, the Michigan jurisdictional share of the net costs of the Unit 1 turbine replacement was $9 million. Future rate recovery of the regulatory asset will be reviewed in a future rate proceeding.

2011 Indiana Base Rate Case

In September 2011, I&M filed a request with the IURC for a net annual increase in Indiana base rates of $149 million based upon a return on common equity of 11.15%. The request included an increase in depreciation rates that would result in a $25 million increase in annual depreciation expense.

Carbon Capture and Sequestration Project with the Department of Energy (DOE) (Commercial Scale Project)

During 2010, AEPSC, on behalf of APCo, began the project definition stage for the potential construction of a new commercial scale carbon capture and sequestration (CCS) facility at the Mountaineer Plant. The DOE agreed to fund 50% of allowable costs incurred for the CCS facility up to a maximum of $334 million. A Front-End Engineering and Design (FEED) study was completed during the third quarter of 2011. Management postponed any further CCS project activities because of the uncertainty about the regulation of CO_2. In June 2011, the FEED study costs were allocated among the AEP East companies, PSO and SWEPCo based on eligible plants that could potentially benefit from the carbon capture. As of December 31, 2011, the project has incurred $34 million in total project costs and has received $20 million of DOE and other eligible funding resulting in $14 million of net costs. The remaining net costs are recorded in regulatory assets on the balance sheets. I&M's portion of remaining net costs is $1.7 million. If the costs of the CCS project cannot be recovered, it would reduce future net income and cash flows.

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service charges and collected, at the FERC's direction, load-based charges, referred to as RTO SECA through March 2006. Intervenors objected and the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies recognized gross SECA revenues of $220 million. I&M's portion of recognized gross SECA revenues is $41.3 million.

In 2006, a FERC Administrative Law Judge issued an initial decision finding that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made.

AEP filed briefs jointly with other affected companies asking the FERC to reverse the decision. In May 2010, the FERC issued an order that generally supported AEP's position and required a compliance filing to be filed with the FERC by August 2010.

The AEP East companies provided reserves for net refunds for SECA settlements totaling $44 million applicable to the $220 million of SECA revenues collected. I&M's portion of the provision is $8.3 million.

Settlements approved by the FERC consumed $10 million of the reserve for refunds applicable to $112 million of SECA revenue. In December 2010, the FERC issued an order approving a settlement agreement resulting in the collection of $2 million of previously deemed uncollectible SECA revenue. Therefore, the AEP East companies reduced their reserves for net refunds for SECA settlements by $2 million. The balance in the reserve for future settlements as of December 31, 2011 was $32 million. I&M's reserve balance as of December 31, 2011 was $5.9 million.

In August 2010, the affected companies, including the AEP East companies, filed a compliance filing with the FERC. If the compliance filing is accepted, the AEP East companies would have to pay refunds of approximately $20 million including estimated interest of $5 million. The AEP East companies could also potentially receive payments up to approximately $10 million including estimated interest of $3 million. A decision is pending from the FERC. I&M's portion of potential refund payments is $3.7 million and potential payments to be received is $1.9 million.

Based on the analysis of the May 2010 order and the compliance filing, management believes that the reserve is adequate to pay the refunds, including interest, that will be required should the compliance filing be made final. Management cannot predict the ultimate outcome of this proceeding at the FERC which could impact future net income and cash flows.

Possible Termination of the Interconnection Agreement

In December 2010, each of the AEP Power Pool members gave notice to AEPSC and each other of their decision to terminate the Interconnection Agreement effective January 2014 or such other date approved by FERC, subject to state regulatory input. If any of the AEP Power Pool members experience decreases in revenues or increases in costs as a result of the termination of the AEP Power Pool and are unable to recover the change in revenues and costs through rates, prices or additional sales, it could reduce future net income and cash flows.

PJM/MISO Market Flow Calculation Settlement Adjustments

During 2009, an analysis conducted by MISO and PJM discovered several instances of unaccounted for power flows on numerous coordinated flowgates. These flows affected the settlement data for congestion revenues and expenses and dated back to the start of the MISO market in 2005. In January 2011, PJM and MISO reached a settlement agreement where the parties agreed to net various issues to zero. In June 2011, the FERC approved the settlement agreement.

3. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	December 31, 2011	December 31, 2010	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			
Litigation Settlement	$ 10,803	$ -	
Mountaineer Carbon Capture and Storage Commercial Scale Facility	1,680	-	
Total Regulatory Assets Not Yet Being Recovered	12,483	-	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Customer Choice Implementation Costs	4,680	6,767	2 years
Unamortized Loss on Reacquired Debt	2,276	2,483	11 years
RTO Formation/Integration Costs	3,858	4,437	8 years
Under-recovered Fuel Costs	95	92	1 year
Other Regulatory Assets Being Recovered	-	1,103	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	291,392	268,080	13 years
Income Tax Assets	222,020	195,671	37 years
Cook Nuclear Plant Refueling Outage Levelization	40,551	53,795	2 years
Off-system Sales Margin Sharing	-	13,091	
Postemployment Benefits	9,137	8,968	4 years
Under-recovered Fuel Costs	8,876	8,467	1 year
Deferred PJM Fees	21,746	7,078	1 year
Deferred Severance Costs	4,952	6,217	4 years
Asset Retirement Obligation	3,396	2,700	9 years
Postretirement Benefits	342	1,857	1 year
Other Regulatory Assets Being Recovered	4,339	4,202	various
Total Regulatory Assets Being Recovered	617,660	585,008	
Total FERC Account 182.3 Regulatory Assets	$ 630,143	$ 585,008	

Regulatory Liabilities:	December 31, 2011	December 31, 2010	Remaining Refund Period
	(in thousands)		
Regulatory liabilities not yet being paid:			
Regulatory Liabilities Currently Paying a Return			
Other Regulatory Liabilities Not Yet Being Paid	$ 318	$ -	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Not Yet Being Paid	136	147	
Regulatory Liabilities Not Yet Being Paid	454	147	
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Not Paying a Return			
Unrealized Gain on Forward Commitments	21,785	28,045	5 years
Income Tax Liabilities	33,271	36,218	37 years
Excess Asset Retirement Obligations for Nuclear Decommissioning Liability	377,162	353,689	(a)
Spent Nuclear Fuel Liability	42,603	41,932	(a)
Over-recovery of PJM Expenses	-	11,671	
Energy Efficiency/Peak Demand Reduction	11,078	1,288	1 year
Off-system Sales Margin Sharing	5,892	-	1 year
Indiana Clean Coal Technology Rider Liability	1,242	2,494	1 year
Other Regulatory Liabilities Being Paid	198	-	various
Regulatory Liabilities Being Paid	493,231	475,337	
Total FERC Account 254 Regulatory Liabilities	$ 493,685	$ 475,484	

(a) Relieved when plant is decommissioned.

4. 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 adverse 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. Management forecasts approximately $468 million of construction expenditures, excluding equity AFUDC and capitalized interest, for 2012. 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 at December 31, 2011:

Contractual Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 331,673	$ 427,890	$ 276,480	$ 45,700	$ 1,081,743
Energy and Capacity Purchase Contracts (b)	1,068	612	326	-	2,006
Construction Contracts for Capital Assets (c)	1,217	-	-	-	1,217
Total	$ 333,958	$ 428,502	$ 276,806	$ 45,700	$ 1,084,966

(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 contractual commitments for energy and capacity purchase contracts.
(c) 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 projects 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 credit facilities totaling $3.25 billion, under which up to $1.35 billion may be issued as letters of credit. In July 2011, AEP replaced the $1.5 billion facility due in 2012 with a new $1.75 billion facility maturing in July 2016 and extended the $1.5 billion facility due in 2013 to expire in June 2015. As of December 31, 2011, I&M's maximum future payment of the letters of credit was $150 thousand with a maturity of March 2012.

In March 2011, I&M and certain other companies in the AEP System terminated a $478 million credit agreement that was scheduled to mature in April 2011 and was used to support $472 million of variable rate Pollution Control Bonds. In March 2011, I&M remarketed $77 million of variable rate Pollution Control Bonds supported by $77.9 million of bilateral letters of credit maturing in March 2013.

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, 2011, there were no material liabilities recorded for any indemnifications.

APCo, I&M and OPCo are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies related to purchase power 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 10 for disclosure of lease residual value guarantees.

ENVIRONMENTAL CONTINGENCIES

Carbon Dioxide Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate CO_2 emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. In 2010, the U.S. Supreme Court granted the defendants' petition for review. In June 2011, the U.S. Supreme Court reversed and remanded the case to the Court of Appeals, finding that plaintiffs' federal common law claims are displaced by the regulatory authority granted to the Federal EPA under the CAA. After the remand, the plaintiffs asked the Second Circuit to return the case to the district court so that they could withdraw their complaints. The cases were returned to the district court and the plaintiffs' federal common law claims were dismissed in December 2011.

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. Management believes the claims are without merit, and in addition to other defenses, are barred by the doctrine of collateral estoppel and the applicable statute of limitations. Management intends to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

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. The plaintiffs appealed the decision. The defendants requested that the court defer setting this case for oral argument until after the Supreme Court issues its decision in the CO_2 public nuisance case discussed above. The court accepted supplemental briefing on the impact of the Supreme Court's decision and heard oral argument in November 2011. Management believes the action is without merit and intends to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

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 generating 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. At December 31, 2011, there is one site for which I&M has received an information request which could lead to a Potentially Responsible Party (PRP) designation. I&M has also been named potentially liable at two sites under state law including the site discussed in the next paragraph. In those instances where I&M has been named a 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 and recorded a provision of approximately $10 million. As the remediation work is completed, I&M's cost may continue to increase 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 2009. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste ranges from $831 million to $1.5 billion in 2009 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 amount recovered in rates was $14 million in 2011 and $14 million in 2010. Decommissioning costs recovered from customers are deposited in external trusts.

At December 31, 2011 and 2010, the total decommissioning trust fund balance was $1.3 billion and $1.2 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, cash flows and possibly financial condition would be adversely affected 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. At December 31, 2011 and 2010, fees and related interest of $265 million and $265 million, respectively, for fuel consumed prior to April 7, 1983 have been recorded as Long-term Debt and funds collected from customers along with related earnings totaling $308 million and $307 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 $14 million to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2013. The proceeds reduced capital costs for dry cask storage.

See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 8 for disclosure of the fair value of assets within the trusts.

Nuclear Incident Liability

I&M carries insurance coverage for property damage, decommissioning and decontamination at the Cook Plant in the amount of $1.8 billion. I&M purchases $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurance requires a contingent financial obligation of up to $41 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 $12.6 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 $117.5 million on each licensed reactor in the U.S. payable in annual installments of $17.5 million. As a result, I&M could be assessed $235 million per nuclear incident payable in annual installments of $35 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 $12.2 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, net income, cash flows and financial condition could be adversely affected.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in significant turbine damage and a small fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. Repair of the property damage and replacement of the turbine rotors and other equipment cost approximately $400 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. Due to the extensive lead time required to manufacture and install new turbine rotors, I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. The installation of the new turbine rotors and other equipment occurred as planned during the fall 2011 refueling outage of Unit 1.

I&M maintains insurance through NEIL. As of December 31, 2011, I&M recorded $64 million on its balance sheet representing amounts due from NEIL under the insurance policies. Through December 31, 2011, I&M received partial payments of $203 million from NEIL for the cost incurred to date to repair the property damage.

NEIL is reviewing claims made under the insurance policies to ensure that claims associated with the outage are covered by the policies. The review by NEIL includes the timing of the unit's return to service and whether the return should have occurred earlier reducing the amount received under the accidental outage policy. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and 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 have a material adverse effect on net income, cash flows and financial condition.

Fort Wayne Lease

Since 1975, I&M has leased certain energy delivery assets from the City of Fort Wayne, Indiana under a long-term lease that expired on February 28, 2010. I&M negotiated with Fort Wayne to purchase the assets at the end of the lease and reached an agreement (subject to IURC approval) in 2010. The agreement required I&M to purchase the remaining leased property and settled claims Fort Wayne asserted. The agreement provided that I&M pay Fort Wayne a total of $39 million, including interest, over 15 years and Fort Wayne recognized that I&M is the exclusive electricity supplier in the Fort Wayne area. In August 2011, the IURC approved a settlement agreement with the Indiana Office of Utility Consumer Counselor. The transaction is final.

5. 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 one unfunded nonqualified pension plan. 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 medical and life insurance benefits for retired employees.

I&M recognizes the funded status associated with defined benefit pension and OPEB plans in the balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. I&M recognizes an asset for a plan's overfunded status or a liability for a plan's underfunded status, and 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	**2011**	**2010**	**2011**	**2010**
Discount Rate	4.55 %	5.05 %	4.75 %	5.25 %
Rate of Compensation Increase (a)	4.75 %	4.90 %	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 similar to those included in the Moody's Aa bond index is constructed with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2011, 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 the average increase of 4.75%.

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	**2011**	**2010**	**2011**	**2010**
Discount Rate	5.05 %	5.60 %	5.25 %	5.85 %
Expected Return on Plan Assets	7.75 %	8.00 %	7.50 %	8.00 %
Rate of Compensation Increase	4.75 %	4.55 %	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	2011	2010
Initial	7.50 %	8.00 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2016	2016

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	$ 2,928	$ (2,334)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	32,910	(26,859)

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. At December 31, 2011, 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, 2011 and 2010

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	
	2011	2010	2011	2010
Change in Benefit Obligation	(in thousands)			
Benefit Obligation at January 1	$ 560,553	$ 525,804	$ 262,931	$ 238,288
Service Cost	9,447	15,284	6,119	6,750
Interest Cost	27,706	29,064	13,404	13,976
Actuarial Loss	17,310	40,836	28,139	20,592
Plan Amendment Prior Service Credit	-	-	(24,845)	(4,273)
Benefit Payments	(33,767)	(50,435)	(17,960)	(17,099)
Participant Contributions	-	-	4,112	3,526
Medicare Subsidy	-	-	1,111	1,171
Benefit Obligation at December 31	$ 581,249	$ 560,553	$ 273,011	$ 262,931
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 451,242	$ 379,159	$ 188,690	$ 166,682
Actual Gain (Loss) on Plan Assets	32,769	50,770	(3,946)	20,983
Company Contributions	53,227	71,748	10,341	14,598
Participant Contributions	-	-	4,112	3,526
Benefit Payments	(33,767)	(50,435)	(17,960)	(17,099)
Fair Value of Plan Assets at December 31	$ 503,471	$ 451,242	$ 181,237	$ 188,690
Underfunded Status at December 31	$ (77,778)	$ (109,311)	$ (91,774)	$ (74,241)

Amounts Recognized on the Balance Sheets as of December 31, 2011 and 2010

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2011	2010	2011	2010
	(in thousands)			
Miscellaneous Current and Accrued Liabilities – Short-term Benefit Liability	$ (57)	$ (57)	$ -	$ -
Accumulated Provision for Pensions and Benefits – Long-term Benefit Liability	(77,721)	(109,254)	(91,774)	(74,241)
Underfunded Status	$ (77,778)	$ (109,311)	$ (91,774)	$ (74,241)

Amounts Included in AOCI and Regulatory Assets as of December 31, 2011 and 2010

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2011	2010	2011	2010
Components	(in thousands)			
Net Actuarial Loss	$ 215,746	$ 208,520	$ 119,224	$ 77,082
Prior Service Cost (Credit)	1,307	2,050	(27,491)	(2,882)
Recorded as				
Regulatory Assets	$ 207,237	$ 199,982	$ 84,155	$ 68,098
Deferred Income Taxes	3,435	3,706	2,653	2,136
Net of Tax AOCI	6,381	6,882	4,925	3,966

Components of the change in amounts included in AOCI and Regulatory Assets during the years ended December 31, 2011 and 2010 are as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
Components	2011	2010	2011	2010
	(in thousands)			
Actuarial Loss During the Year	$ 21,360	$ 24,879	$ 45,584	$ 12,984
Prior Service Credit	-	-	(24,845)	(4,273)
Amortization of Actuarial Loss	(14,134)	(10,057)	(3,442)	(3,449)
Amortization of Prior Service Credit (Cost)	(743)	(742)	236	-
Amortization of Transition Obligation	-	-	-	(2,627)
Change for the Year	$ 6,483	$ 14,080	$ 17,533	$ 2,635

Pension and Other Postretirement Plans' Assets

The following table presents the classification of pension plan assets within the fair value hierarchy at December 31, 2011:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 170,210	$ -	$ -	$ -	$ 170,210	33.8 %
International	46,667	-	-	-	46,667	9.3 %
Real Estate Investment Trusts	12,168	-	-	-	12,168	2.4 %
Common Collective Trust - International	-	15,030	-	-	15,030	3.0 %
Subtotal - Equities	229,045	15,030	-	-	244,075	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	3,072	-	-	3,072	0.6 %
United States Government and Agency Securities	-	66,195	-	-	66,195	13.2 %
Corporate Debt	-	115,209	746	-	115,955	23.0 %
Foreign Debt	-	22,308	-	-	22,308	4.4 %
State and Local Government	-	5,623	-	-	5,623	1.1 %
Other - Asset Backed	-	3,042	-	-	3,042	0.6 %
Subtotal - Fixed Income	-	215,449	746	-	216,195	42.9 %
Real Estate	-	-	19,112	-	19,112	3.8 %
Alternative Investments	-	-	18,762	-	18,762	3.7 %
Securities Lending	-	25,130	-	-	25,130	5.0 %
Securities Lending Collateral (a)	-	-	-	(27,589)	(27,589)	(5.5)%
Cash and Cash Equivalents	-	10,855	-	-	10,855	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(3,069)	(3,069)	(0.6)%
Total	$ 229,045	$ 266,464	$ 38,620	$ (30,658)	$ 503,471	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 pension assets:

	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2011	$ -	$ 9,732	$ 15,205	$ 24,937
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	2,611	1,018	3,629
Relating to Assets Sold During the Period	-	-	349	349
Purchases and Sales	-	6,769	2,190	8,959
Transfers into Level 3	746	-	-	746
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2011	$ 746	$ 19,112	$ 18,762	$ 38,620

The following table presents the classification of OPEB plan assets within the fair value hierarchy at December 31, 2011:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 44,707	$ -	$ -	$ -	$ 44,707	24.7 %
International	48,897	-	-	-	48,897	27.0 %
Common Collective Trust - Global	-	12,748	-	-	12,748	7.0 %
Subtotal - Equities	93,604	12,748	-	-	106,352	58.7 %
Fixed Income:						
Common Collective Trust - Debt	-	8,898	-	-	8,898	4.9 %
United States Government and Agency Securities	-	10,386	-	-	10,386	5.7 %
Corporate Debt	-	19,558	-	-	19,558	10.8 %
Foreign Debt	-	4,146	-	-	4,146	2.3 %
State and Local Government	-	1,082	-	-	1,082	0.6 %
Other - Asset Backed	-	246	-	-	246	0.1 %
Subtotal - Fixed Income	-	44,316	-	-	44,316	24.4 %
Trust Owned Life Insurance:						
International Equities	-	5,943	-	-	5,943	3.3 %
United States Bonds	-	20,290	-	-	20,290	11.2 %
Cash and Cash Equivalents	2,161	3,010	-	-	5,171	2.9 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	(835)	(835)	(0.5)%
Total	$ 95,765	$ 86,307	$ -	$ (835)	$ 181,237	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 at December 31, 2010:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 157,871	$ 322	$ -	$ -	$ 158,193	35.1 %
International	47,126	-	-	-	47,126	10.4 %
Real Estate Investment Trusts	13,139	-	-	-	13,139	2.9 %
Common Collective Trust - International	-	19,023	-	-	19,023	4.2 %
Subtotal - Equities	218,136	19,345	-	-	237,481	52.6 %
Fixed Income:						
United States Government and Agency Securities	-	74,158	-	-	74,158	16.4 %
Corporate Debt	-	78,571	-	-	78,571	17.4 %
Foreign Debt	-	14,871	-	-	14,871	3.3 %
State and Local Government	-	2,658	-	-	2,658	0.6 %
Other - Asset Backed	-	5,981	-	-	5,981	1.3 %
Subtotal - Fixed Income	-	176,239	-	-	176,239	39.0 %
Real Estate	-	-	9,732	-	9,732	2.2 %
Alternative Investments	-	-	15,205	-	15,205	3.4 %
Securities Lending	-	29,744	-	-	29,744	6.6 %
Securities Lending Collateral (a)	-	-	-	(32,260)	(32,260)	(7.1)%
Cash and Cash Equivalents (b)	-	14,844	-	186	15,030	3.3 %
Other - Pending Transactions and Accrued Income (c)	-	-	-	71	71	- %
Total	$ 218,136	$ 240,172	$ 24,937	$ (32,003)	$ 451,242	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 foreign currency holdings.
(c) 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 real estate and alternative investments classified as Level 3 in the fair value hierarchy for pension assets:

	Real Estate	Alternative Investments	Total Level 3
		(in thousands)	
Balance as of January 1, 2010	$ 10,083	$ 11,773	$ 21,856
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(351)	557	206
Relating to Assets Sold During the Period	-	181	181
Purchases and Sales	-	2,694	2,694
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2010	$ 9,732	$ 15,205	$ 24,937

The following table presents the classification of OPEB plan assets within the fair value hierarchy at December 31, 2010:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 75,446	$ -	$ -	$ -	$ 75,446	40.0 %
International	28,479	-	-	-	28,479	15.1 %
Common Collective Trust - Global	-	14,825	-	-	14,825	7.9 %
Subtotal - Equities	103,925	14,825	-	-	118,750	63.0 %
Fixed Income:						
Common Collective Trust - Debt	-	6,166	-	-	6,166	3.3 %
United States Government and Agency Securities	-	12,103	-	-	12,103	6.4 %
Corporate Debt	-	14,215	-	-	14,215	7.5 %
Foreign Debt	-	3,204	-	-	3,204	1.7 %
State and Local Government	-	452	-	-	452	0.2 %
Other - Asset Backed	-	122	-	-	122	0.1 %
Subtotal - Fixed Income	-	36,262	-	-	36,262	19.2 %
Trust Owned Life Insurance:						
International Equities	-	6,338	-	-	6,338	3.3 %
United States Bonds	-	21,000	-	-	21,000	11.1 %
Cash and Cash Equivalents (a)	2,649	3,234	-	111	5,994	3.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	346	346	0.2 %
Total	$ 106,574	$ 81,659	$ -	$ 457	$ 188,690	100.0 %

(a) Amounts in "Other" column primarily represent foreign currency holdings.
(b) 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 based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

Accumulated Benefit Obligation	December 31, 2011	2010
	(in thousands)	
Qualified Pension Plan	$ 569,428	$ 551,272
Nonqualified Pension Plans	168	994
Total	$ 569,596	$ 552,266

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 at December 31, 2011 and 2010 were as follows:

	December 31, 2011	2010
	(in thousands)	
Projected Benefit Obligation	$ 581,249	$ 560,553
Accumulated Benefit Obligation	$ 569,596	$ 552,266
Fair Value of Plan Assets	503,471	451,242
Underfunded Accumulated Benefit Obligation	$ (66,125)	$ (101,024)

Estimated Future Benefit Payments and Contributions

I&M expects contributions and payments for the pension plans of $24 million and the OPEB plans of $13.1 million during 2012. The estimated pension benefit payments for the unfunded plan and contributions to the trust are at least the minimum amount required by the Employee Retirement Income Security Act plus payment of unfunded nonqualified benefits. For the qualified pension plan, additional discretionary contributions may be made to the trust to maintain the funded status of the plan. The contributions to the OPEB plans are generally based on the amount of the OPEB plans' periodic benefit costs for accounting purposes as provided in agreements with state regulatory authorities, plus the additional discretionary contribution of the Medicare subsidy receipts.

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 December 2011, the prescription drug plan was amended for certain participants. The impact of the change is reflected in the Benefit Plan Obligation table as a plan amendment. As a result of this amendment to the plan, the Medicare subsidy receipts in the following table are reduced from prior published estimates. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for the pension benefits and OPEB are as follows:

		Other Postretirement Benefit Plans	
	Pension Plans	Benefit Payments	Medicare Subsidy Receipts
		(in thousands)	
2012	$ 34,976	$ 17,541	$ 1,068
2013	35,656	17,983	-
2014	37,259	18,783	-
2015	37,800	19,816	-
2016	39,751	21,078	-
Years 2017 to 2021, in Total	213,231	121,941	-

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost for the years ended December 31, 2011 and 2010:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2011	2010	2011	2010
	(in thousands)			
Service Cost	$ 9,447	$ 15,284	$ 6,119	$ 6,750
Interest Cost	27,706	29,064	13,404	13,976
Expected Return on Plan Assets	(36,820)	(35,003)	(13,886)	(13,396)
Amortization of Transition Obligation	-	-	-	2,627
Amortization of Prior Service Cost (Credit)	743	742	(236)	-
Amortization of Net Actuarial Loss	14,134	10,057	3,442	3,449
Net Periodic Benefit Cost	15,210	20,144	8,843	13,406
Capitalized Portion	(3,164)	(4,029)	(1,839)	(2,681)
Net Periodic Benefit Cost Recognized as Expense	$ 12,046	$ 16,115	$ 7,004	$ 10,725

Estimated amounts expected to be amortized to net periodic benefit costs and the impact on the balance sheet during 2012 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
Net Actuarial Loss	$ 16,903	$ 7,188
Prior Service Cost (Credit)	406	(2,383)
Total Estimated 2012 Amortization	$ 17,309	$ 4,805
Expected to be Recorded as		
Regulatory Asset	$ 16,303	$ 4,400
Deferred Income Taxes	352	142
Net of Tax AOCI	654	263
Total	$ 17,309	$ 4,805

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 who are not members of the United Mine Workers of America (UMWA). 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 plan for the years ended December 31, 2011 and 2010 was $9.5 million and $9 million, respectively.

UMWA Benefits

I&M provides UMWA pension, health and welfare benefits for certain unionized mining employees, retirees and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds. I&M administers the health and welfare benefits and pays them from its general assets.

The UMWA pension benefits are administered through a multiemployer plan that is different from single-employer plans as an employer's contributions may be used to provide benefits to employees of other participating employers. Required contributions not made by an employer may result in other employers bearing the unfunded plan obligations, while a withdrawing employer may be subject to a withdrawal liability. UMWA pension benefits are provided through the United Mine Workers of America 1974 Pension Plan (Employer Identification Number: 52-1050282, Plan Number 002), which under the Pension Protection Act of 2006 (PPA) was in Seriously Endangered Status for the plan years ending June 30, 2011 and 2010, without utilization of extended amortization provisions. The Plan is required under the PPA to adopt a funding improvement plan by May 25, 2012. Contributions in 2011 and 2010 were immaterial and represent less than 5% of the total contributions in the plan's latest annual report for the years ended June 30, 2011 and 2010. Contributions did not include a surcharge, and there are no minimum contributions for future years.

6. BUSINESS SEGMENTS

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

7. 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, 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

Trading Strategies

The strategy surrounding the use of derivative instruments for trading purposes focuses 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.

Risk Management Strategies

The strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. To accomplish these objectives, AEPSC, on behalf of I&M, primarily employs risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. 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 degree, heating oil and gasoline, emission allowance 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, 2011 and 2010:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume December 31, 2011	Volume December 31, 2010	Unit of Measure
	(in thousands)		
Commodity:			
Power	109,326	117,862	MWHs
Coal	1,920	6,571	Tons
Natural Gas	5,081	1,302	MMBtus
Heating Oil and Gasoline	525	521	Gallons
Interest Rate	$ 19,890	$ 5,732	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, 2011 and 2010 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,			
2011		2010	
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)			
$ 2,752	$ 18,547	$ 1,087	$ 9,757

The following tables represent the gross fair value derivative activity on the balance sheets as of December 31, 2011 and 2010:

Fair Value of Derivative Instruments
December 31, 2011

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Other (b)	Total
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)		
			(in thousands)		
Derivative Instrument Assets	$ 222,675	$ -	$ -	$ (161,438)	$ 61,237
Long-Term Portion of Derivative Instrument Assets	68,047	-	-	(38,702)	29,345
Derivative Instrument Assets – Hedges	-	725	-	(448)	277
Long-Term Portion of Derivative Instrument Assets – Hedges	-	58	-	(41)	17
Derivative Instrument Liabilities	201,907	-	-	(178,216)	23,691
Long-Term Portion of Derivative Instrument Liabilities	52,441	-	-	(44,390)	8,051
Derivative Instrument Liabilities – Hedges	-	1,971	10,637	(448)	12,160
Long-Term Portion of Derivative Instrument Liabilities – Hedges	-	224	10,637	(41)	10,820

Fair Value of Derivative Instruments
December 31, 2010

Balance Sheet Location	Risk Management Contracts	Hedging Contracts			
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in thousands)		
Derivative Instrument Assets	$ 219,050	$ -	$ -	$ (160,214)	$ 58,836
Long-Term Portion of Derivative Instrument Assets	56,154	-	-	(24,677)	31,477
Derivative Instrument Assets – Hedges	-	1,580	-	(1,405)	175
Long-Term Portion of Derivative Instrument Assets – Hedges	-	429	-	(421)	8
Derivative Instrument Liabilities	193,789	-	-	(170,911)	22,878
Long-Term Portion of Derivative Instrument Liabilities	37,039	-	-	(30,509)	6,530
Derivative Instrument Liabilities – Hedges	-	1,842	-	(1,405)	437
Long-Term Portion of Derivative Instrument Liabilities – Hedges	-	421	-	(421)	-

(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." Amounts also include de-designated risk management contracts.

The table below presents the activity of derivative risk management contracts for the years ended December 31, 2011 and 2010:

Amount of Gain (Loss) Recognized on Risk Management Contracts Years Ended December 31, 2011 and 2010

Location of Gain (Loss)	2011	2010
	(in thousands)	
Operating Revenues	$ 12,878	$ 19,363
Regulatory Assets (a)	(1,470)	(186)
Regulatory Liabilities (a)	(5,178)	8,217
Total Gain on Risk Management Contracts	$ 6,230	$ 27,394

(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 Charges on the statements of income. During 2011 and 2010, I&M did not employ 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, natural gas and heating oil and gasoline designated as cash flow hedges are included in Operating Revenues, 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 2011 and 2010, I&M designated commodity derivatives as cash flow hedges.

I&M reclassifies gains and losses on financial fuel 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 2011 and 2010, 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 into Interest Charges in those periods in which hedged interest payments occur. During 2011, 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 that were designated as the hedged items in qualifying foreign currency hedging relationships.

During 2011 and 2010, hedge ineffectiveness was immaterial or nonexistent for all of the cash flow hedge strategies disclosed above.

The following tables provide 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 years ended December 31, 2011 and 2010. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2011

	Commodity Contracts	Interest Rate and Foreign Currency Contracts	Total Contracts
		(in thousands)	
Balance in AOCI as of December 31, 2010	$ (178)	$ (8,507)	$ (8,685)
Changes in Fair Value Recognized in AOCI	(1,294)	(6,913)	(8,207)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Operating Revenues	544	-	544
Operation Expenses	8	-	8
Maintenance Expenses	(64)	-	(64)
Interest on Long-Term Debt	-	955	955
Utility Plant	(90)	-	(90)
Regulatory Assets (a)	255	-	255
Balance in AOCI as of December 31, 2011	$ (819)	$ (14,465)	$ (15,284)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2010

	Commodity Contracts	Interest Rate and Foreign Currency Contracts	Total Contracts
		(in thousands)	
Balance in AOCI as of December 31, 2009	$ (382)	$ (9514)	$ (9,896)
Changes in Fair Value Recognized in AOCI	(901)	-	(901)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Operating Revenues	87	-	87
Operation Expenses	864	-	864
Maintenance Expenses	(28)	-	(28)
Interest on Long-Term Debt	-	1,007	1,007
Utility Plant	(36)	-	(36)
Regulatory Assets (a)	218	-	218
Balance in AOCI as of December 31, 2010	$ (178)	$ (8,507)	$ (8,685)

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

Cash flow hedges included in Accumulated Other Comprehensive Income on the balance sheets at December 31, 2011 and 2010 were:

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2011

	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Hedging Assets (a)	$ 277	$ -	$ 277
Hedging Liabilities (a)	1,523	10,637	12,160
AOCI Loss Net of Tax	(819)	(14,465)	(15,284)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(712)	(595)	(1,307)

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2010

	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Hedging Assets (a)	$ 175	$ -	$ 175
Hedging Liabilities (a)	(437)	-	(437)
AOCI Loss Net of Tax	(178)	(8,507)	(8,685)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(184)	(955)	(1,139)

(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, 2011, 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 related to forecasted transactions is 29 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.

AEPSC, on behalf of I&M, uses standardized master agreements which 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 aggregate 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, 2011 and 2010:

	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, 2011	$ 6,418	$ 3,983	$ 3,983
December 31, 2010	3,965	7,581	7,561

As of December 31, 2011 and 2010, I&M was not required to post any collateral.

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. Management does not anticipate a non-performance event under these provisions. 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, 2011 and 2010:

	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, 2011	$ 59,936	$ 5,200	$ 28,339
December 31, 2010	46,188	3,991	14,280

8. 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. 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, 2011 and 2010 are summarized in the following table:

December 31,			
2011		2010	
Book Value	Fair Value	Book Value	Fair Value
(in thousands)			
$ 1,823,085	$ 2,098,470	$ 1,801,473	$ 1,957,211

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 at December 31, 2011 and 2010:

	December 31, 2011			2010		
	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	$ 18,229	$ -	$ -	$ 20,039	$ -	$ -
Fixed Income Securities:						
United States Government	543,506	60,946	(547)	461,084	22,582	(1,489)
Corporate Debt	53,979	4,932	(1,536)	59,463	3,716	(1,905)
State and Local Government	329,986	(430)	(2,236)	340,786	(975)	(340)
Subtotal Fixed Income Securities	927,471	65,448	(4,319)	861,333	25,323	(3,734)
Equity Securities - Domestic	646,032	214,748	(79,536)	633,855	183,447	(122,889)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,591,732	$ 280,196	$ (83,855)	$ 1,515,227	$ 208,770	$ (126,623)

The following table provides the securities activity within the decommissioning and SNF trusts for the years ended December 31, 2011 and 2010:

	Years Ended December 31, 2011	2010
	(in thousands)	
Proceeds from Investment Sales	$ 1,110,909	$ 1,361,813
Purchases of Investments	1,166,690	1,414,473
Gross Realized Gains on Investment Sales	33,382	11,570
Gross Realized Losses on Investment Sales	22,159	2,087

The adjusted cost of debt securities was $862 million and $835 million as of December 31, 2011 and 2010, respectively. The adjusted cost of equity securities was $431 million and $451 million as of December 31, 2011 and 2010, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, at December 31, 2011 was as follows:

	Fair Value of Debt Securities (in thousands)
Within 1 year	$ 62,383
1 year – 5 years	284,942
5 years – 10 years	349,587
After 10 years	230,559
Total	$ 927,471

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, the financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2011 and 2010. 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, 2011

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (e)	$ 3,001	$ 203,175	$ 16,305	$ (162,227)	$ 60,254
Dedesignated Risk Management Contracts (b)	-	-	-	983	983
Total Derivative Instrument Assets	3,001	203,175	16,305	(161,244)	61,237
Derivative Instrument Assets – Hedges					
Cash Flow Hedges – Commodity (a)	-	702	-	(425)	277
Other Special Funds					
Cash and Cash Equivalents (c)	-	5,431	-	12,798	18,229
Fixed Income Securities:					
United States Government	-	543,506	-	-	543,506
Corporate Debt	-	53,979	-	-	53,979
State and Local Government	-	329,986	-	-	329,986
Subtotal Fixed Income Securities	-	927,471	-	-	927,471
Equity Securities – Domestic (d)	646,032	-	-	-	646,032
Total Other Special Funds	646,032	932,902	-	12,798	1,591,732
Total Assets	$ 649,033	$ 1,136,779	$ 16,305	$ (148,871)	$ 1,653,246
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a) (e)	$ 1,626	$ 185,092	$ 14,995	$ (178,022)	$ 23,691
Derivative Instrument Liabilities - Hedges					
Cash Flow Hedges:					
Commodity (a)	-	1,901	47	(425)	1,523
Interest Rate/Foreign Currency	-	10,637	-	-	10,637
Total Derivative Instrument Liabilities – Hedges	-	12,538	47	(425)	12,160
Total Liabilities	$ 1,626	$ 197,630	$ 15,042	$ (178,447)	$ 35,831

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2010

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (a)(e)	$ 1,014	$ 209,031	$ 8,295	$ (161,531)	$ 56,809
Dedesignated Risk Management Contracts (b)	-	-	-	2,027	2,027
Total Derivative Instrument Assets	1,014	209,031	8,295	(159,504)	58,836
Derivative Instrument Assets – Hedges					
Cash Flow Hedges – Commodity (a)	-	1,533	-	(1,358)	175
Other Special Funds					
Cash and Cash Equivalents (c)	-	7,898	-	12,141	20,039
Fixed Income Securities:					
United States Government	-	461,084	-	-	461,084
Corporate Debt	-	59,463	-	-	59,463
State and Local Government	-	340,786	-	-	340,786
Subtotal Fixed Income Securities	-	861,333	-	-	861,333
Equity Securities – Domestic (d)	633,855	-	-	-	633,855
Total Other Special Funds	633,855	869,231	-	12,141	1,515,227
Total Assets	$ 634,869	$ 1,079,795	$ 8,295	$ (148,721)	$ 1,574,238
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a)(e)	$ 994	$ 186,898	$ 5,187	$ (170,201)	$ 22,878
Derivative Instrument Liabilities - Hedges					
Cash Flow Hedges – Commodity (a)	-	1,795	-	(1,358)	437
Total Liabilities	$ 994	$ 188,693	$ 5,187	$ (171,559)	$ 23,315

(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) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.
(c) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.
(d) Amounts represent publicly traded equity securities and equity-based mutual funds.
(e) Substantially comprised of power contracts.

There have been no transfers between Level 1 and Level 2 during the years ended December 31, 2011 and 2010.

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, 2011	(in thousands)
Balance as of December 31, 2010	$ 3,108
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(1,261)
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	(47)
Purchases, Issuances and Settlements (c)	847
Transfers into Level 3 (d) (f)	1,531
Transfers out of Level 3 (e) (f)	(1,906)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(1,009)
Balance as of December 31, 2011	$ 1,263

Year Ended December 31, 2010	(in thousands)
Balance as of December 31, 2009	$ 4,816
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	963
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)	(4,121)
Transfers into Level 3 (d) (f)	616
Transfers out of Level 3 (e) (f)	(6,558)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	7,392
Balance as of December 31, 2010	$ 3,108

(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) Represents existing assets or liabilities that were previously categorized as Level 3.
(f) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(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.

9. INCOME TAXES

The details of income taxes as reported are as follows:

	Years Ended December 31, 2011	2010
	(in thousands)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ (78,981)	$ 4,490
Deferred	135,782	60,817
Deferred Investment Tax Credits	(2,783)	(2,316)
Total	54,018	62,991
Charged (Credited) to Nonoperating Income, Net:		
Current	(1,434)	(2,723)
Deferred	(956)	2,906
Total	(2,390)	183
Total Income Taxes	$ 51,628	$ 63,174

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 rate and the amount of income taxes reported.

	Years Ended December 31, 2011	2010
	(in thousands)	
Net Income	$ 149,674	$ 126,091
Income Tax Expense	51,628	63,174
Pretax Income	$ 201,302	$ 189,265
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 70,456	$ 66,243
Increase (Decrease) in Income Taxes resulting from the following items:		
Depreciation	7,895	11,419
Nuclear Fuel Disposal Costs	(1,400)	(1,655)
AFUDC	(9,223)	(9,032)
Removal Costs	(5,566)	(3,663)
Investment Tax Credits, Net	(2,783)	(2,316)
State and Local Income Taxes, Net	(1,377)	3,966
Other	(6,374)	(1,788)
Income Tax Expense	$ 51,628	$ 63,174
Effective Income Tax Rate	25.6%	33.4%

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

	December 31, 2011	December 31, 2010
	(in thousands)	
Deferred Tax Assets	$ 774,052	$ 745,791
Deferred Tax Liabilities	(1,712,670)	(1,527,734)
Net Deferred Tax Liabilities	$ (938,618)	$ (781,943)
Property Related Temporary Differences	$ (317,265)	$ (247,670)
Amounts Due from Customers for Future Federal Income Taxes	(28,551)	(27,932)
Deferred State Income Taxes	(107,751)	(79,879)
Deferred Income Taxes on Other Comprehensive Loss	14,319	10,519
Accrued Nuclear Decommissioning Expense	(435,916)	(394,441)
Postretirement Benefits	50,121	40,852
Accrued Pensions	27,953	36,693
Regulatory Assets	(116,474)	(108,842)
All Other, Net	(25,054)	(11,243)
Net Deferred Tax Liabilities	$ (938,618)	$ (781,943)

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 2009. I&M and other AEP subsidiaries completed the examination of the years 2007 and 2008 in April 2011 and settled all outstanding issues on appeal for the years 2001 through 2006 in October 2011. The settlements did not have a material impact on I&M's net income, cash flows or financial condition. The IRS examination of years 2009 and 2010 started in October 2011. 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 have a material effect on 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. Management believes that previously filed tax returns have positions that may be challenged by these tax authorities. However, 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. With few exceptions, I&M and other AEP subsidiaries are no longer subject to state or local income tax examinations by tax authorities for years before 2000.

Net Income Tax Operating Loss Carryforward

In 2011, I&M sustained 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. As a result, I&M accrued deferred federal income tax benefits in 2011 and expects to realize the federal cash flow benefits in future periods as there was insufficient capacity in prior periods to carry the net operating losses back. Management anticipates future taxable income will be sufficient to realize the net income tax operating loss tax benefits before the federal carryforward expires after 2031.

Tax Credit Carryforward

The AEP System sustained consolidated federal income tax net operating losses in 2011 and 2009. These losses and lower consolidated federal taxable income in 2010 resulted in unused federal income tax credits. At December 31, 2011 I&M had federal tax credit carryforwards as indicated in the table below. If these credits are not utilized, federal general business tax credits will expire in the years 2028 through 2031.

Total Federal Tax Credit Carryforward	Federal Tax Credit Carryforward Subject to Expiration
(in thousands)	
$ 3,863	$ 2,564

Management 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, interest income and reversal of prior period interest expense:

	Years Ended December 31, 2011	2010
	(in thousands)	
Interest Expense	$ -	$ 366
Interest Income	2,234	-
Reversal of Prior Period Interest Expense	1,075	159

The following table shows balances for amounts accrued for the receipt of interest and payment of interest and penalties:

	December 31, 2011	December 31, 2010
	(in thousands)	
Accrual for Receipt of Interest	$ 630	$ 5,829
Accrual for Payment of Interest and Penalties	145	1,823

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

	2011	2010
	(in thousands)	
Balance at January 1,	$ 23,134	$ 20,007
Increase - Tax Positions Taken During a Prior Period	9,256	4,964
Decrease - Tax Positions Taken During a Prior Period	(8,622)	(24)
Decrease - Tax Positions Taken During the Current Year	-	(1,487)
Decrease - Settlements with Taxing Authorities	(6,687)	(236)
Decrease - Lapse of the Applicable Statute of Limitations	(3,010)	(90)
Balance at December 31,	$ 14,071	$ 23,134

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 $654 thousand and $1.7 million for 2011 and 2010, respectively.

Federal Tax Legislation

The American Recovery and Reinvestment Act of 2009 provided for several new grant programs and expanded tax credits and an extension of the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The enacted provisions did not have a material impact on net income or financial condition. However, the bonus depreciation contributed to AEP's 2009 federal net operating tax loss that resulted in a 2010 cash flow benefit of $78.5 million to I&M.

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (Health Care Acts) were enacted in March 2010. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the Medicare Part D prescription drug subsidy will no longer be deductible by the employer for federal income tax purposes effective for years beginning after December 31, 2012. Because of the loss of the future tax deduction, a reduction in the deferred tax asset related to the nondeductible OPEB liabilities accrued to date was recorded in March 2010. This reduction, which was partially offset by recording net tax regulatory assets, did not materially affect cash flows or financial condition, but decreased net income by approximately $0.6 million for the year ended December 31, 2010.

The Small Business Jobs Act (the Act) was enacted in September 2010. Included in the Act was a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, the Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2010 and 2011. The enacted provisions did not have a material impact on net income or financial condition but had a favorable impact on cash flows in 2010 of $50 million.

In December 2011, the U.S. Treasury Department issued guidance regarding the deduction and capitalization of expenditures related to tangible property. The guidance was in the form of proposed and temporary regulations and generally is effective for tax years beginning in 2012. These regulations did not have an impact on net income or cash flows in 2011. Management is still evaluating the impact these regulations will have on future periods.

State Tax Legislation

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

In May 2011, Michigan repealed its Business Tax regime and replaced it with a traditional corporate net income tax with a rate of 6%, effective January 1, 2012.

During the third quarter of 2011, the state of West Virginia determined that the State had achieved certain minimum levels of shortfall reserve funds and thus, the West Virginia corporate income tax rate will be reduced to 7.75% in 2012. The enacted provisions will not have a material impact on net income, cash flows or financial condition.

10. LEASES

Leases of property, plant and equipment are for periods up to 35 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 in accordance with rate-making treatment for regulated operations. The components of rental costs are as follows:

	Years Ended December 31,	
	2011	2010
	(in thousands)	
Net Lease Expense on Operating Leases	$ 94,317	$ 91,973
Amortization of Capital Leases	103,361	106,614
Interest on Capital Leases	8,751	3,860
Total Lease Rental Costs	$ 206,429	$ 202,447

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

	December 31, 2011	2010
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 16,100	$ 19,147
Other Property, Plant and Equipment	216,087	199,921
Total Property, Plant and Equipment	232,187	219,068
Accumulated Amortization	12,779	10,366
Net Property, Plant and Equipment Under Capital Leases	$ 219,408	$ 208,702
Obligations Under Capital Leases:		
Noncurrent	$ 140,888	$ 138,956
Current	78,520	69,746
Total Obligations Under Capital Leases	$ 219,408	$ 208,702

Future minimum lease payments consisted of the following at December 31, 2011:

	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2012	$ 91,210	$ 99,114
2013	80,043	98,625
2014	44,792	97,825
2015	9,807	94,694
2016	3,391	89,368
Later Years	13,998	506,585
Total Future Minimum Lease Payments	243,241	$ 986,211
Less Estimated Interest Element	23,833	
Estimated Present Value of Future Minimum Lease Payments	$ 219,408	

Master Lease Agreements

I&M leases certain equipment under master lease agreements. In December 2010, management signed a new master lease agreement with GE Capital Commercial Inc. (GE) to replace existing operating and capital leases with GE. These assets were included in existing master lease agreements that were to be terminated in 2011 since GE exercised the termination provision related to these leases in 2008. In January 2011, certain previously leased assets not included in the 2010 refinancing were purchased.

For equipment under the GE master lease agreements, the lessor is guaranteed receipt of up to 78% of the unamortized balance of the equipment at the end of the lease term. If the fair value of the leased equipment is below the unamortized balance at the end of the lease term, I&M is committed to pay the difference between the fair value and the unamortized balance, with the total guarantee not to exceed 78% of the unamortized balance. For equipment under other master 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. At December 31, 2011, the maximum potential loss for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term is $2.1 million. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

Rockport Lease

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

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it equally to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. AEP, AEGCo and I&M have no ownership interest in the Owner Trustee and do not guarantee its debt. I&M's future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2011 are as follows:

Future Minimum Lease Payments	**(in millions)**
2012	$ 74
2013	74
2014	74
2015	74
2016	74
Later Years	443
Total Future Minimum Lease Payments	$ 813

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 these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligation is $16 million for the remaining railcars as of December 31, 2011. 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 84% under the current five year lease term to 77% at the end of the 20-year term of the projected fair value of the equipment. I&M has assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is approximately $12 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 Lease

In December 2007, I&M entered into a sale-and-leaseback transaction with Citicorp Leasing, Inc. (CLI), an unrelated, unconsolidated, wholly-owned subsidiary of Citibank, N.A. to lease nuclear fuel for I&M's Cook Plant. In December 2007, I&M sold a portion of its unamortized nuclear fuel inventory to CLI at cost for $85 million. The lease has a variable rate based on one month LIBOR and is accounted for as a capital lease with lease terms up to 60 months. The future payment obligations of $383 thousand are included in the future minimum lease payments schedule earlier in this note. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2011 are $383 thousand for 2012, based on estimated fuel burn.

In September 2009, I&M entered into a nuclear fuel sale and leaseback transaction for $102.3 million with DCC Fuel LLC (DCC) to lease nuclear fuel for the Cook Plant. DCC 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 5.44% and is accounted for as a capital lease with a lease term of 48 months. I&M makes payments on the lease semi-annually on April 1 and October 1. Payments began in April 2010. The net capital lease asset is included in Utility Plant.

In April 2010, I&M entered into a nuclear fuel 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 accounted for as a capital lease with a lease term of 54 months. I&M makes payments on the lease semi-annually on April 1 and October 1. Payments began in October 2010.

In December 2010, I&M entered into a nuclear fuel 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 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 accounted for as a capital lease with a lease term of 54 months. I&M makes payments on the lease monthly. Payments began in January 2011.

In November 2011, I&M entered into a nuclear fuel 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 accounted for as a capital lease with a lease term of 54 months. I&M makes payments on the lease quarterly on February 1, May 1, August 1 and November 1. Payments began in February 2012.

11. FINANCING ACTIVITIES

Preferred Stock

In December 2011, I&M redeemed all of its outstanding preferred stock, resulting in a loss. The redeemed shares are no longer outstanding and represent only the right to receive the applicable redemption price, to the extent the shares have not yet been presented for payment. The par value of preferred stock redeemed and the loss recorded was $8.1 million and $314 thousand, respectively.

	Number of Shares Redeemed for the Years Ended December 31,	
Series	2011	2010
4.12 %	11,055	-
4.125 %	55,257	44
4.56 %	14,412	-

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, 2011 and 2010:

Type of Debt	Maturity	Weighted Average Interest Rate at December 31, 2011	Interest Rate Ranges at December 31, 2011	Interest Rate Ranges at December 31, 2010	Outstanding at December 31, 2011	Outstanding at December 31, 2010
					(in thousands)	
Senior Unsecured Notes	2012-2037	6.25%	5.05%-7.00%	5.05%-7.00%	$ 1,275,000	$ 1,275,000
Pollution Control Bonds (a)	2012-2025 (b)	4.02%	0.06%-6.25%	0.33%-6.25%	267,000	267,000
Spent Nuclear Fuel Liability (c)					265,065	264,901
Other Long-term Debt	2025	6.00%	6.00%	-	20,927	-
Unamortized Discount, Net					(4,907)	(5,428)
Total Long-term Debt					$ 1,823,085	$ 1,801,473

(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, standby bond purchase agreements 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 4).

Long-term debt outstanding at December 31, 2011 is payable as follows:

	(in thousands)
2012	$ 177,455
2013	918
2014	276,055
2015	126,121
2016	1,360
After 2016	1,246,083
Principal Amount	1,827,992
Unamortized Discount, Net	(4,907)
Total Long-term Debt Outstanding	$ 1,823,085

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. As applicable, management understands "capital account" to mean the value of the common stock.

Additionally, the Federal Power Act creates a reserve on earnings attributable to hydroelectric generating 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%. At December 31, 2011, none 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 the subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans to the Utility Money Pool as of December 31, 2011 is included in Notes Receivable from Associated Companies on the balance sheets. The amount of outstanding borrowings from the Utility Money Pool as of December 31, 2010 is included in Notes Payable to Associated Companies in the balance sheets. I&M's money pool activity and its corresponding authorized borrowing limits for the years ended December 31, 2011 and 2010 are described in the following table:

Years Ended December 31,	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans (Borrowings) to/from Utility Money Pool as of December 31	Authorized Short-term Borrowing Limit
			(in thousands)			
2011	$ 57,352	$ 214,030	$ 23,793	$ 67,202	$ 90,442	$ 500,000
2010	48,105	217,788	21,597	103,981	(48,105)	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, 2011 and 2010 were as follows:

Years Ended December 31,	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2011	0.53%	0.11%	0.56%	0.06%	0.39%	0.39%
2010	0.53%	0.15%	0.55%	0.09%	0.41%	0.24%

Interest expense related to the Utility Money Pool is included in Interest Charges. I&M incurred interest expense for amounts borrowed from the Utility Money Pool of $24 thousand and $20 thousand for the years ended December 31, 2011 and 2010, respectively.

Interest income related to the Utility Money Pool is included in Interest and Dividend Income. I&M earned interest income for amounts advanced to the Utility Money Pool of $211 thousand and $208 thousand for the years ended December 31, 2011 and 2010, respectively.

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 4.

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 and administrative costs and I&M's uncollectible accounts experience. I&M manages and services its customer accounts receivable sold.

In July 2011, AEP Credit renewed its receivables securitization agreement. The agreement provides commitments of $750 million from bank conduits to finance receivables from AEP Credit with an increase to $800 million for the months of July, August and September to accommodate seasonal demand. A commitment of $375 million, with the seasonal increase to $425 million for the months of July, August and September, expires in June 2012 and the remaining commitment of $375 million expires in June 2014.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement as of December 31, 2011 and 2010 was $121.6 million and $123.4 million, respectively.

The fees paid to AEP Credit for customer accounts receivable sold were $6.2 million and $6.8 million for the years ended December 31, 2011 and 2010, respectively.

I&M's proceeds on the sale of receivables to AEP Credit were $1.3 billion and $1.3 billion for the years ended December 31, 2011 and 2010, respectively.

12. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "AEP System Tax Allocation Agreement" section of Note 9 in addition to "Utility Money Pool – AEP System" and "Sale of Receivables – AEP Credit" sections of Note 11.

AEP Power Pool

APCo, I&M, KPCo, OPCo and AEPSC are parties to the Interconnection Agreement, which defines the sharing of costs and benefits associated with their generating plants. This sharing is based upon each AEP utility subsidiary's MLR and is 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. In addition, APCo, I&M, KPCo and OPCo are parties to the AEP System Interim Allowance Agreement, which provides, among other things, for the transfer of SO_2 allowances associated with the transactions under the Interconnection Agreement.

Power, gas and risk management activities are conducted by AEPSC and profits and losses are allocated under the SIA to AEP Power Pool members, PSO and SWEPCo. Risk management activities involve the purchase and sale of electricity and gas under physical forward contracts at fixed and variable prices. In addition, the risk management of electricity, and to a lesser extent gas contracts, includes exchange traded futures and options and OTC options and swaps. The majority of these transactions represent physical forward contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. In addition, AEPSC enters into transactions for the purchase and sale of electricity and gas options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

CSW Operating Agreement

PSO, SWEPCo and AEPSC are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement), which was approved by the FERC. The CSW 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 the use of 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 and the CSW 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 CSW 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 CSW Operating Agreement, power generated that is not needed to serve the native load of the AEP System is sold in the wholesale market by AEPSC on behalf of the generating company.

Affiliated Revenues and Purchases

The following table shows the revenues derived from sales to the pools, direct sales to affiliates, net transmission agreement sales, natural gas contracts with AEPES and other revenues for the years ended December 31, 2011 and 2010:

Related Party Revenues	Years Ended December 31, 2011	2010
	(in thousands)	
Sales to AEP Power Pool	$ 308,336	$ 327,992
Direct Sales to West Affiliates	908	1,931
Transmission Agreement and Transmission Coordination Agreement Sales	9,379	-
Direct Sales to Transmission Companies	-	1,848
Natural Gas Contracts with AEPES	92	(1,087)
Other Revenues	1,469	267

The following table shows the purchased power expense incurred for purchases from the pools and affiliates for the years ended December 31, 2011 and 2010:

Related Party Purchases	Years Ended December 31, 2011	2010
	(in thousands)	
Purchases from AEP Power Pool	$ 124,598	$ 91,129
Direct Purchases from West Affiliates	147	466
Purchases from AEGCo	228,739	235,740

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, KPCo and OPCo are parties to the TA, dated April 1, 1984, as amended, defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kV and above) and certain facilities operated at lower voltages (138 kV and above). Like the Interconnection Agreement, this sharing is based upon each company's MLR. The FERC approved a new TA effective November 2010. The impacts of the new TA will be phased-in for retail rates, adds KGPCo and WPCo as parties to the agreement and changes the allocation method.

I&M's net charges recorded related to the new TA for the year ended December 31, 2011 were $1.5 million and net credits under the original TA for the year ended December 31, 2010 were $25.2 million. The charges and credits 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. Effective May 2011, TNC is no longer a party to the agreement. 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 Open Access Transmission Tariff (OATT) filed with the FERC and the rules of the FERC relating to such a tariff.

Fuel Agreement between OPCo and AEPES

OPCo and National Power Cooperative, Inc (NPC) have an agreement whereby OPCo operates a 500 MW gas plant owned by NPC (Mone Plant). AEPES entered into a fuel management agreement with OPCo and NPC to manage and procure fuel for the Mone Plant. The gas purchased by AEPES and used in generation is first sold to OPCo then allocated to the AEP East companies, who have an agreement to purchase 100% of the available generating capacity from the plant through May 2012. I&M's purchases of gas managed by AEPES were $523 thousand and $547 thousand for the years ended December 31, 2011 and 2010, respectively. The purchases are reflected in Operation Expenses.

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. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

UPA between AEGCo and KPCo

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

Cook Coal Terminal

Cook Coal Terminal, a division of OPCo, performs coal transloading services at cost for I&M. I&M recorded the cost of $21.9 million and $17.2 million for transloading services in Fuel Stock for the years ended December 31, 2011 and 2010, respectively.

Cook Coal Terminal also performs railcar maintenance services at cost for I&M. I&M paid OPCo $3 million and $1.9 million for railcar maintenance for the years ended December 31, 2011 and 2010, respectively. 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 $2.9 million and $1.8 million for railcar services provided in 2011 and 2010, respectively. These costs are recorded in Fuel Stock on the balance sheets.

I&M Barging, Urea Transloading and Other Services

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_X emissions at certain generation plants in the AEP System. I&M recorded revenues from barging, transloading and other services of $105.4 million and $105.8 million for the years ended December 31, 2011 and 2010, respectively, in Revenues from Nonutility Operations.

In addition, I&M provided transloading services to OVEC. I&M recorded revenues of $116 thousand and $112 thousand for 2011 and 2010, 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, 2011 and 2010, I&M recorded the costs of $24 million and $28 million, respectively, as Operation Expenses.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. I&M recorded APCo's billings as capital or maintenance expense depending on the nature of the services received. These billings are recoverable from customers. I&M was billed $2.2 million and $2.1 million for the years ended December 31, 2011 and 2010, respectively.

Affiliate Coal Purchases

In 2008, OPCo entered into contracts to sell excess coal purchases to certain AEP subsidiaries through 2010. I&M's realized and unrealized amount recorded for the year ended December 31, 2010 was $1.4 million.

Affiliate Railcar Agreement

I&M has an agreement providing for the use of its affiliates' 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 these costs or reimbursements as costs or reduction of costs, respectively, in Fuel Stock on the balance sheets and such costs are recoverable from customers. Under the agreement I&M billed its affiliates $3.7 million and $3.5 million and paid its affiliates $2.1 and $2.3 million for the years ended December 31, 2011 and 2010, respectively.

Purchased Power from OVEC

The amounts of power purchased from OVEC for the years ended December 31, 2011 and 2010 were $57.2 million and $52.7 million, respectively. The amounts are recoverable from customers and are included in Operation Expenses.

AEP Power Pool Purchases from OVEC

In 2011, the AEP Power Pool purchased power from OVEC to serve off-system sales and retail sales. These purchases are reported in Operation Expenses. The amount recorded for the year ended December 31, 2011 was $12.9 million.

In January 2010, the AEP Power Pool began purchasing power from OVEC to serve off-system sales and retail sales through June 2010. I&M's purchases serving off-system sales of $3.7 million are reported net as a reduction in Operating Revenues. I&M's purchases serving retail sales of $2 million are reported in Operation Expenses.

Sales and Purchases of Property – Transmission Companies

In 2009, AEP Transmission Company, LLC (AEP Transco) formed seven wholly-owned transmission companies. AEP Transco is the holding company for the seven transmission companies. In 2011, AEP Indiana Michigan Transmission Company, Inc. sold $1.2 million of transmission property to I&M that were recorded at net book value in Utility Plant. There were no gains or losses recorded on the transactions.

Sales and Purchases of Property

I&M had affiliated sales and purchases of electric property individually amounting to $100 thousand or more for the years ended December 31, 2011 and 2010 as shown in the following tables:

Companies	Years Ended December 31, 2011	2010
	(in thousands)	
APCo to I&M	277	1,090
I&M to APCo	-	444
I&M to OPCo	-	485
I&M to SWEPCo	-	218
OPCo to I&M	848	2,435

In addition, I&M had aggregate affiliated sales and purchases of meters and transformers for the years ended December 31, 2011 and 2010 as shown in the following table:

	APCo	KPCo	OPCo	PSO	SWEPCo	TCC	TNC	WPCo	Total
	(in thousands)								
Sales									
2011	$ 61	$ -	$ 324	$ 10	$ 15	$ 14	$ 2	$ 15	$ 441
2010	138	7	356	116	1	-	63	14	695
Purchases									
2011	$ 38	$ 10	$ 1,338	$ -	$ -	$ 11	$ -	$ -	$ 1,397
2010	112	6	432	-	4	38	-	-	592

The amounts above are recorded in Utility Plant at cost.

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 bases 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 $126.5 million and $139.9 million for the years ended December 31, 2011 and 2010, respectively.

13. 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 the annual composite depreciation rates by functional class:

Year	Nuclear	Steam	Hydro	Transmission	Distribution	General
				(in percentages)		
2011	1.2	2.2	2.4	1.4	2.4	7.4
2010	1.2	2.2	2.4	1.4	2.5	11.7

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, 2011 and 2010, I&M's ARO liability for nuclear decommissioning of the Cook Plant was $979 million and $930 million, respectively. As of December 31, 2011 and 2010, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $1.3 billion and $1.2 billion, respectively. These assets are included in Other Special Funds.

The following is a reconciliation of the 2011 and 2010 aggregate carrying amounts of ARO related to nuclear decommissioning, ash disposal facilities and asbestos removal:

Year	ARO at January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31,
			(in thousands)			
2011	$ 963,029	$ 51,308	$ -	$ (1,370)	$ 155	$ 1,013,122
2010	894,746	47,844	7,216	(1,694)	14,917	963,029

Jointly-owned Electric Facilities

I&M has electric facilities that are jointly-owned with an affiliated company. Using its own financing, each participating company 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 at December 31, 2011		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
Rockport Generating Plant (Unit No. 1) (a)	Coal	50.0 %	$ 759,033	$ 19,357	$ 443,857

			Company's Share at December 31, 2010		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
Rockport Generating Plant (Unit No. 1) (a)	Coal	50.0 %	$ 742,538	$ 25,304	$ 437,371

(a) Operated by I&M.

14. COST REDUCTION INITIATIVES

In April 2010, management began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. A total of 2,461 positions was eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment May 31, 2010. The severance program provided two weeks of base pay for every year of service along with other severance benefits.

Management recorded a charge to expense during 2010 primarily related to severance benefits as the result of headcount reduction initiatives. The total amount incurred in 2010 was $45.0 million.

I&M's cost reduction activity for the year ended December 31, 2011 is described in the following table:

Balance at December 31, 2010	Incurred	Settled	Adjustments	Balance at December 31, 2011
		(in thousands)		
$ 2,198	$ -	$ (2,006)	$ (192)	$ -

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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)	6,493,434,512	6,493,434,512
4	Property Under Capital Leases	24,483,672	24,483,672
5	Plant Purchased or Sold		
6	Completed Construction not Classified	358,747,034	358,747,034
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	6,876,665,218	6,876,665,218
9	Leased to Others		
10	Held for Future Use	7,732,413	7,732,413
11	Construction Work in Progress	236,095,869	236,095,869
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	7,120,493,500	7,120,493,500
14	Accum Prov for Depr, Amort, & Depl	3,424,425,300	3,424,425,300
15	Net Utility Plant (13 less 14)	3,696,068,200	3,696,068,200
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	3,296,679,098	3,296,679,098
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	127,742,121	127,742,121
22	Total In Service (18 thru 21)	3,424,421,219	3,424,421,219
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	4,081	4,081
29	Amortization		
30	Total Held for Future Use (28 & 29)	4,081	4,081
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	3,424,425,300	3,424,425,300

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Company	(2) [ ] A Resubmission		December 31, 2011

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)
200	14	b	MPSC adopted the FERC Uniform System of Accounts for electric utilities in Case No. U-14811. In previous years, the MPSC permitted I&M to record decommissioning expense in conformance with FERC Uniform System of Accounts for general ledger purposes, but required I&M to reclass the Michigan portion of this expense from account 524 to account 403 for Michigan reporting purposes. I&M has restated the amount for the previous year to reflect the adoption of FERC Uniform System of accounts.
200	18	b	MPSC adopted the FERC Uniform System of Accounts for electric utilities in Case No. U-14811. In previous years, the MPSC permitted I&M to record decommissioning expense in conformance with FERC Uniform System of Accounts for general ledger purposes, but required I&M to reclass the Michigan portion of this expense from account 524 to account 403 for Michigan reporting purposes. I&M has restated the amount for the previous year to reflect the adoption of FERC Uniform System of accounts.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	82,472,218	102,043,327
4	Allowance for Funds Used during Construction	11,234,372	12,046,988
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	93,706,590	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)	180,310,269	110,088,032
10	SUBTOTAL (Total 8 & 9)	180,310,269	
11	Spent Nuclear Fuel (120.4)	261,667,212	55,583,518
12	Nuclear Fuel Under Capital Leases (120.6)	175,474,706	109,975,030
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	384,155,662	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	327,003,115	
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 2011/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance End of Year	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)	(f)	
			1
			2
	95,960,923	88,554,622	3
	14,127,109	9,154,251	4
			5
		97,708,873	6
			7
			8
	165,558,518	124,839,783	9
		124,839,783	10
	61,629,344	255,621,386	11
96,743,780		188,705,956	12
-40,326,275	62,357,522	362,124,415	13
		304,751,583	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
$55,583,518

Reclassification of nuclear fuel from owned to leased due to sale/leaseback with 3rd party
$109,975,000

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

Retirement of spent fuel

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

Reclassification of $109,975,000 of nuclear fuel from owned to leased due to sale/leaseback with 3rd party

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

Includes 2011 costs in connection with nuclear fuel leases:

Finance charges	$6,058,371
Administrative and legal	$ 204,000

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

Retirement of spent fuel

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2011

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	108,835,767	11,654,365
5	TOTAL Intangible Plant	**128,819,291**	**11,654,365**
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	149,868,674	2,870,953
11	312 Boiler Plant Equipment	901,943,217	32,625,630
12	313 Engines and Engine-Driven Generators	0	0
13	314 Turbogenerator Units	185,724,811	3,426,110
14	315 Accessory Electric Equipment	88,069,971	2,106,761
15	316 Miscellaneous Power Plant Equipment	30,320,040	702,068
16	317 Asset Retirement Costs for Steam Production	25,692,313	175,472
17	TOTAL Steam Production Plant	**1,393,164,207**	**41,906,994**
18	Nuclear Production Plant		
19	320.1 Land	1,879,588	0
20	320.2 Land Rights	0	0
21	321 Structures and Improvements	320,851,838	26,564,503
22	322 Reactor Plant Equipment	1,159,126,529	16,632,116
23	323 Turbogenerator Units	348,778,563	134,284,983
24	324 Accessory Electric Equipment	162,340,901	1,483,089

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
2,298,338	0	0	118,191,794	303	4
2,298,338	**0**	**0**	**138,175,318**		5
					6
					7
0	0	0	11,323,112	310.1	8
0	0	0	222,069	310.2	9
211,436	0	0	152,528,191	311	10
13,279,859	0	0	921,288,988	312	11
0	0	0	0	313	12
762,501	0	0	188,388,420	314	13
537,249	0	(1,908,491)	87,730,992	315	14
24,442	0	0	30,997,666	316	15
	0	0	25,867,785	317	16
14,815,487	**0**	(1,908,491)	**1,418,347,223**		17
					18
0	0	0	1,879,588	320.1	19
0	0	0	0	320.2	20
2,182,146	0	0	345,234,195	321	21
3,315,728	0	0	1,172,442,917	322	22
48,961,707	0	0	434,101,839	323	23
343,450	0	0	163,480,540	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, 2011

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Addition (c)
24	325 Miscellaneous Power Plant Equipment	163,744,839	14,278,778
25	326 Asset Retirement Costs for Nuclear Production	151,397,582	0
26	TOTAL Nuclear Production Plant	**2,308,119,840**	**193,243,469**
27	Hydraulic Production Plant		
28	330.1 Land	510,360	0
29	330.2 Land Rights	196,186	0
30	331 Structures and Improvements	3,118,017	140,390
31	332 Reservoirs, Dams and Waterways	18,938,846	215,202
32	333 Water Wheels, Turbines and Generators	16,144,061	111,818
33	334 Accessory Electric Equipment	5,278,302	0
34	335 Miscellaneous Power Plant Equipment	1,941,960	150,494
35	336 Roads, Railroads and Bridges	853	0
36	337 Asset Retirement Costs for Hydraulic Production	242,144	0
37	TOTAL Hydraulic Production Plant	**46,370,729**	**617,904**
38	Other Production Plant		
39	340.1 Land	0	0
40	340.2 Land Rights	0	0
41	341 Structures and Improvements	0	0
42	342 Fuel Holders, Products and Accessories	0	0
43	343 Prime Movers	0	0
44	344 Generators	0	0
45	345 Accessory Electric Equipment	0	0
46	346 Miscellaneous Power Plant Equipment	0	0
47	347 Asset Retirement Costs for Other Production	0	0
48	TOTAL Other Production Plant	**0**	**0**
49	TOTAL Production Plant	**3,747,654,776**	**235,768,367**
50	3. TRANSMISSION PLANT		
51	350.1 Land	6,864,866	39,160
52	350.2 Land Rights	52,424,730	(855,257)
53	352 Structures and Improvements	20,328,159	456,247
54	353 Station Equipment	555,078,989	24,457,425
55	354 Towers and Fixtures	221,794,655	441,475
56	355 Poles and Fixtures	99,040,374	6,484,958
57	356 Overhead Conductors and Devices	226,113,826	7,852,181
58	357 Underground Conduit	1,555,251	659,914
59	358 Underground Conductors and Devices	4,916,516	263,047

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, 2011

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
7,227,700	0	0	170,795,917	325	24
0	0	0	151,397,582	326	25
62,030,731	**0**	**0**	**2,439,332,578**		26
					27
0	0	0	510,360	330.1	28
0	0	0	196,186	330.2	29
42,816	0	0	3,215,591	331	30
110,939	0	0	19,043,109	332	31
71,613	0	0	16,184,266	333	32
0	0	0	5,278,302	334	33
2,464	0	0	2,089,990	335	34
0	0	0	853	336	35
0	0	0	242,144	337	36
227,832	**0**	**0**	**46,760,801**		37
					38
0	0	0	0	340.1	39
0	0	0	0	340.2	40
0	0	0	0	341	41
0	0	0	0	342	42
0	0	0	0	343	43
0	0	0	0	344	44
0	0	0	0	345	45
0	0	0	0	346	46
0	0	0	0	347	47
0	**0**	**0**	**0**		48
77,074,050	**0**	(1,908,491)	**3,904,440,602**		49
					50
4,794	0	0	6,899,232	350.1	51
0	0	0	51,569,473	350.2	52
24,258	0	0	20,760,148	352	53
4,247,396	0	2,139,764	577,428,782	353	54
25,868	0	0	222,210,262	354	55
799,981	0	(21,977)	104,703,374	355	56
691,003	0	(2,951)	233,272,053	356	57
0	0	0	2,215,165	357	58
0	0	0	5,179,563	358	59

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, 2011

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
57	359 Roads and Trails	349,749	0
58	359.1 Asset Retirement Costs for Transmission Plant	0	0
59	TOTAL Transmission Plant	**1,188,467,115**	**39,799,150**
60	4. DISTRIBUTION PLANT		
61	360.1 Land	4,102,530	155,848
62	360.2 Land Rights	11,471,199	754,677
63	361 Structures and Improvements	7,441,047	1,563,495
64	362 Station Equipment	163,181,492	17,989,979
65	363 Storage Battery Equipment	5,488,476	0
66	364 Poles, Towers and Fixtures	208,583,422	8,419,692
67	365 Overhead Conductors and Devices	282,464,130	9,450,546
68	366 Underground Conduit	58,863,562	4,424,772
69	367 Underground Conductors and Devices	170,548,299	7,377,588
70	368 Line Transformers	247,824,890	12,051,165
71	368.1 Capacitors	0	
72	369 Services	138,628,255	7,899,394
73	370 Meters	75,360,868	11,320,525
74	371 Installations on Customers' Premises	18,870,741	1,834,082
75	372 Leased Property on Customers' Premises	0	
76	373 Street Lighting and Signal Systems	18,113,934	400,136
77	374 Asset Retirement Costs for Distribution Plant	0	0
78	TOTAL Distribution Plant	**1,410,942,845**	**83,641,899**
79	5. GENERAL PLANT		
80	389.1 Land	2,102,245	0
81	389.2 Lands Rights	178,388	0
82	390 Structures and Improvments	51,343,311	2,044,913
83	391 Office Furniture and Equipment	5,621,955	539,635
84	391.1 Computers / Computer Related Equipment	0	0
85	392 Transportation Equipment	0	0
86	393 Stores Equipment	31,796	4,825
87	394 Tools, Shop and Garage Equipment	8,548,833	827,480
88	395 Laboratory Equipment	290,657	5,657
89	396 Power Operated Equipment	543,218	1,538
90	397 Communication Equipment	23,993,231	581,302
91	398 Miscellaneous Equipment	7,494,760	122,641
92	SUBTOTAL	**100,148,394**	**4,127,991**

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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	57
0	0	0	0	359.1	58
5,793,300	**0**	**2,114,836**	**1,224,587,801**		59
					60
0	0	0	4,258,378	360.1	61
0	0	0	12,225,876	360.2	62
38,966	0	0	8,965,576	361	63
1,368,161	0	13,948	179,817,258	362	64
0	0	0	5,488,476	363	65
860,755	0	21,977	216,164,336	364	66
2,748,368	0	2,951	289,169,259	365	67
146,238	0	0	63,142,096	366	68
539,916	0	0	177,385,971	367	69
2,865,357	0	0	257,010,698	368	70
0	0	0	0	368.1	71
681,316	0	0	145,846,333	369	72
2,645,802	0	(580,596)	83,454,995	370	73
453,592	0	0	20,251,231	371	74
0	0	0	0	372	75
239,450	0	0	18,274,620	373	76
0	0	0	0	374	77
12,587,921	**0**	(541,720)	**1,481,455,103**		78
					79
2,044	0	0	2,100,201	389.1	80
0	0	0	178,388	389.2	81
783,061	0	136,398	52,741,561	390	82
191,618	0	0	5,969,972	391	83
0	0	0	0	391.1	84
0	0	0	0	392	85
0	0	0	36,621	393	86
56,771	0	0	9,319,542	394	87
3,359	0	0	292,955	395	88
0	0	0	544,756	396	89
374,962	0	335,375	24,534,946	397	90
0	0	0	7,617,401	398	91
1,411,815	**0**	**471,773**	**103,336,343**		92

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
91	399 Other Tangible Property	0	0
92	399.1 Asset Retirement Costs for General Plant	191,891	0
93	TOTAL General Plant	**100,340,285**	**4,127,991**
94	TOTAL (Accounts 101 and 106)	**6,576,224,312**	**374,991,772**
95			
96	102 Electric Plant Purchased	0	0
97	(Less) 102 Electric Plant Sold	0	0
98	103 Experimental Plant Unclassified	0	0
99	TOTAL Electric Plant in Service *(Total of lines 94 thru 98)*	**6,576,224,312**	**374,991,772**

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, 2011

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	91
5,512	0	0	186,379	399.1	92
1,417,327	**0**	**471,773**	**103,522,722**		93
99,170,936	**0**	**136,398**	**6,852,181,546**		94
					95
0	0	0	0	102	96
0	0	0	0		97
0	0	0	0	103	98
99,170,936	**0**	**136,398**	**6,852,181,546**		99

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 31,2011

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.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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		5,905,682
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			426,464
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			7,732,413

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, 2011

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						

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2011

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	Forestry IM IN D Base R W	7,950,609		0
2	Forestry IM MI D Base R W	2,395,959		0
3	TS/I&M/Purchase-Rebuild Maj Eq	3,197,598		0
4	TS/IN/Replace & Refurbish	2,163,379		0
5	TSMIReplace Refurbish	1,545,791		0
6	TLIMINConcord-NW Elkhart	2,363,487		0
7	IM/IN/Ft Wayne Nwk Prot Rplcmt	1,107,174		0
8	IM/Jones Ck Sta T Line ROW	1,485,033		0
9	IM/IN/Ellison Sta - Purchase	1,965,417		0
10	I&M Next Generation Radio Syst	11,540,998		7,475,333
11	gridSMART-I&M	3,009,203		0
12	U2 Control Room Annunc. Replac	1,289,161		15,330,803
13	U1 Control Room Annunc Replace	1,802,792		15,818,391
14	Unit 2 PPC Replacement	2,023,272		17,650,045
15	Unit 1 PPC Replacement	2,316,390		18,300,309
16	Dry Cask Storage	13,415,801		73,332,715
17	U2 GSU Replacement (TR-2)	22,499,534		6,054,709
18	TR1ABCD Replacement	1,172,580		6,795,955
19	U2 FW Heaters LP	1,552,588		21,158,812
20	U2 Feedwater Htrs HP	1,009,475		42,251,096
21	Cyber Attacks Process LAN	3,001,642		5,545,226
22	CK U1 Sec Sys Wtr Chem Upgrade	11,011,128		4,153,870
23	U2 Sec Sys Wtr Chem Upgrade	10,664,607		4,124,836
24	EPU/LCM Mods	44,584,209		1,039,202,653
25	U2 MSR & FW Heater Digital Cnt	3,549,906		12,831,450
26	U2 MSR Valve/Piping Optimizat	2,546,275		5,212,849
27	U1 CTS Ht Exchanger - West	1,157,329		4,876,889
28	Ultimate Heat Sink Studies	7,035,285		572,914,087
29	RK U1 DFGD w/ FF	2,871,076		321,448,902
30	Rockport 2 DSI FGD	1,180,668		13,379,237
31	RKP05CIIM Horiz RH ReplaceU1	2,942,831		0
32	RK10 CI U2 Economizer	9,143,067		1,280,713
33	RK11CIU2 Dust Collector TripRm	1,017,333		0
34	TC4 4N GSU Transformer Rewind	5,236,401		0
35	**TOTAL**	**236,095,869**	**358,747,034**	**2,490,347,362**

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, 2011

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	TC411 HP HEATER REPLACEMENT	1,415,397		0
2	TS/I&M/IN/Rockport remove reac	1,067,842		314,575
3	TL/I&M/IN/Rockport-Jefferson 7	3,069,551		1,675,702
4	WS-CI-IMPCo-G PPB	2,765,952		0
5	RP-CI-IMPCo-G NMIB	4,958,271		0
6	ET-CI-IMPCo-T ASSET IMP	2,173,860		0
7	Ed-Ci-Impco-D Ast Imp	5,065,654		0
8	Ed-Ci-Impco-D Cust Serv	1,349,283		0
9	Other Minor Projects Under $1,000,000	22,482,061		279,218,205
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31	Completed Construction Not Classified		358,747,034	
32				
33				
34				
35	**TOTAL**	**236,095,869**	**358,747,034**	**2,490,347,362**

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, 2011

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	5,493,482
2		
3	Nuclear Construction Overheads	5,418,928
4		
5	Transmission Construction Overheads	3,713,919
6		
7	Distribution Construction Overheads	17,597,306
8		
9		
10		
11		
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39	**TOTAL**	**32,223,635**

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, 2011

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, 2011

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	3,257,025,809	3,257,021,839	3,970	
2	Depreciation Prov. for Year, Charged to				
3	(403) Depreciation Expense	107,922,728	107,922,617	111	
4	(403.1) Decommissioning Expense	3,976,605	3,976,605	0	
5	(413) Exp. Of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify):	1,390,088	1,390,088	0	
9					
10	TOTAL Deprec. Prov. For Year *(Enter Total of Lines 3 thru 9)*	**113,289,421**	113,289,310	111	
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	96,506,437	96,428,269	78,168	
13	Cost of Removal	23,310,417	23,388,585	(78,168)	
14	Salvage (Credit)	48,292,124	48,292,124		
15	TOTAL Net Chrgs. For Plant Ret. *(Enter Total of lines 12 thru 14)*	**71,524,730**	71,524,730	0	
16	Net Earnings of Decommissioning Funds				
17	Other Debit or Credit Items (Described)				
18	Retirement WIP	0	0		
19	Asbestos ARO	(1,977,427)	(1,977,427)		
20	Transfer between Accounts 108 & 111	(129,894)	(129,894)	0	
21	Balance End of Year *(Enter total of lines 1, 10, 15, 16 & 17)*	**3,296,683,179**	3,296,679,098	4,081	

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

22	Steam Production	827,055,728	827,055,728	0	
23	Nuclear Production	1,409,396,994	1,409,396,994		
24	Hydraulic Production-Conventional	25,122,926	25,122,926		
25	Hydraulic Production-Pumped Storage	0	0		
26	Other Production	0	0		
27	Transmission	531,736,589	531,732,508	4,081	
28	Distribution	476,915,254	476,915,254		
29	General	26,455,688	26,455,688		
30	TOTAL (Enter total of lines 20 thru 28)	**3,296,683,179**	3,296,679,098	4,081	

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, 2011

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)
219	8	C	Abestos depreciation and accretion expense in account 1080013 - $1,396,765 Amortize Indiana jurisdictional portion of reg asset for ash ponds ARO's - ($6,677) Total $1,390,088
219	1	b	MPSC adopted the FERC Uniform System of Accounts for electric utilities in Case No. U-14811. In previous years, the MPSC permitted I&M to record decommissioning expense in conformance with FERC Uniform System of Accounts for general ledger purposes, but required I&M to reclass the Michigan portion of this expense from account 524 to account 403 for Michigan reporting purposes. I&M has restated the amount for the previous year to reflect the adoption of FERC Uniform System of accounts.
219	3	b	MPSC adopted the FERC Uniform System of Accounts for electric utilities in Case No. U-14811. In previous years, the MPSC permitted I&M to record decommissioning expense in conformance with FERC Uniform System of Accounts for general ledger purposes, but required I&M to reclass the Michigan portion of this expense from account 524 to account 403 for Michigan reporting purposes. I&M has restated the amount for the previous year to reflect the adoption of FERC Uniform System of accounts.

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Name of Respondent	This Report Is:	Date of Report	Year of Report
INDIANA MICHIGAN POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2011

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	22,959,925	2,525,973	25,485,898
2	Office Building Leasehold Improvements, One Summit Square, Fort Wayne, IN	2,695,099		2,695,099
3	Land, purchased in connection with Jefferson West 765kv Corridor, Jefferson County, IN	164,576		164,576
4	Land, Prosperity East 138kv Corridor, Madison County, IN	102,956		102,956
5	Land near Tanners Creek Plant, Lawrenceburg, IN	146,364		146,364
6	Land for Butler Center Substation	110,789		110,789
7	Land for Fuson Substation, Delaware County, IN	0	102,430	102,430
8	Service Building and Site, Marion, IN (transferred to a/c 101 - report remaining land value with minor items Ln 16)	148,875	(148,875)	0
9	Minor items previously devoted to public service	8,174	0	8,174
10	Minor items - other nonutility property	465,611	(5,039)	460,572
	TOTAL	26,802,369	2,474,489	29,276,858

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

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

Line No.	Item (a)	Amount (b)
1	Balance, Beginning of Year	12,348,149
2	Accruals for Year, Charged to	
3	(417) Income from Nonutility Operations	686,082
4	(418) Nonoperating Rental Income	44,884
5	Other Accounts (Specify):	
6	Accounts 227 and 243	1,083,037
7	TOTAL Accruals for Year (Enter Total of lines 3 thru 6)	1,814,003
8	Net Charges for Plant Retired:	
9	Book Cost of Plant Retired	(142,662)
10	Cost of Removal	0
11	Salvage (Credit)	0
12	TOTAL Net Charges (Enter Total of lines 9 thru 11)	(142,662)
13	Other Debit or Credit Items (Describe):	
14	Reclassifications from/to Other Accounts	129,895
15	Balance, End of Year (Enter Total of lines 1, 7, 12, and 14)	14,149,385

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, 2011

INVESTMENTS (Accounts 123, 124, 136)

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

Line No.	Description of Investment (a)	Book Cost at Beginning of Year *(If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference)* (b) Original 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		10,523,251	0
7				
8	Private Fuel Storage LLC		6,283,077	0
9				
10	Fiber Optic Agreements with AEP Communications, Kentucky Data		5,103,191	0
11	Link, Inc, and Citynet Fiber Network, Inc			
12				
13	Speculative Allowance Inventory			
14	- NOx		101	0
15	- SO2		66	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		(16,979)	0
23				
24	Ripley Land Purchase		739,989	5,397
25				
26	Total Account 124		22,922,468	5,397
27				
28	Account 136 - Temporary Cash Investments			
29				
30				
31	Grand Total		22,922,468	5,397

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, 2011

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 of Loss from Improvement Disposed of (h)	Line No.
						1
						2
						3
						4
0			266,733			5
0			10,523,251			6
						7
2,763			6,280,314			8
						9
131,937			4,971,254			10
						11
						12
						13
75			26			14
66			0			15
0			0			16
						17
0			15,000			18
						19
0			8,039			20
						21
0			(16,979)			22
						23
0			745,386			24
						25
134,841			22,793,024			26
						27
						28
						29
						30
134,841	0	0	22,793,024	0	0	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 2011/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			-189,146
5	Investment in Subsidiary AOCI			-1,353,382
6	Subtotal			23,781,472
7				
8	Price River Coal Company, Inc.	12-01-65		
9	Common Stock			27,275
10	Subtotal			27,275
11				
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42	Total Cost of Account 123.1 $ 146,936,960		TOTAL	23,808,747

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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
-41,619		-230,765		4
		-1,629,740		5
-41,619		23,463,495		6
				7
				8
		27,275		9
		27,275		10
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-41,619		23,490,770		42

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, 2011

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)	76,092,138	72,346,209
3	Other Accounts Receivable (Account 143 & 171 & 172) (Disclose any capital stock subscriptions received)	14,507,711	25,518,048
4	TOTAL	**90,599,849**	**97,864,257**
5	Less: Accumulated Provision for Uncollectible Accounts-Cr. (Account 144)	1,692,114	1,749,514
6	TOTAL, Less Accumulated Provision for Uncollectible Accounts	**88,907,735**	**96,114,743**
7			
8	Account 143 includes employee receivables of $762,477 @		
9	12/31/10 and $741,352 @ 12/31/11 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		62,931		1,629,183	1,692,114
2	Prov. For uncollectibles for current year		151,148		0	151,148
3	Account written off (less)		5,109		88,639	93,748
4	Charged to other accounts					0
5	Adjustments (explain):					0
	Adjustment to Beginning Balance		0		0	0
6	Balance end of year	0	208,970	0	1,540,544	**1,749,514**
7						
8						
9						
10						
11						

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2011

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	0	1,190,107,644	1,099,665,323	90,442,321	210,896
3	Account 146					
4	AEP Credit	-			0	
5	AEP Elmwood	550	0	550	0	
6	AEP Generating Company	64,673,944	303,772,841	341,363,972	27,082,813	
7	AEP Memco	4,582,347	17,623,803	20,129,916	2,076,234	
8	AEP Pro Serv	594	16,163	15,473	1,284	
9	AEP Service Corporation	33,080,903	1,316,046,734	1,316,775,586	32,352,051	
10	AEP System Pool (AEPSC)	22,264,634	763,130,204	769,899,783	15,495,055	
11	AEP T&D Services, LLC	37,581	308,865	346,446	(0)	
12	AEP Texas Central	(546)	88,346	99,228	(11,428)	
13	AEP Texas North	395	152,904	125,883	27,416	
14	AEP Utilities, Inc.	1,455,918	163,936,241	163,879,534	1,512,625	
15	AEP Utility Funding LLC	169,541	0	169,541	(0)	
16	AEPES Power Trading	0	4,418	4,418	0	
17	American Electric Power Co	4,744,443	429,713,342	432,034,660	2,423,125	
18	Appalachian Power Co	3,451,349	41,519,103	41,160,066	3,810,385	
19	Blackhawk Coal Company	5,666	40,907	41,511	5,062	
20	Cardinal Operating	1,131,550	5,483,687	6,552,834	62,402	
21	Conesville Coal Prep	2	2	4	0	
22	Cook Coal Terminal	1,286	347,050	341,680	6,655	
23	CSW Energy, Inc.	10	20	30	(0)	

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2011

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	10,375	696,157	693,810	12,722	
2	Kingsport Power Co	35	14,802	12,069	2,768	
3	Ohio Power Co	3,499,205	59,482,020	60,377,785	2,603,440	
4	Public Service Co of Ok	96,899	1,492,888	1,515,028	74,759	
5	Southwestern Power Co	340,859	5,780,091	6,048,389	72,561	
6	Wheeling Power Co	37	21,244	20,485	795	
7	United Sciences	0	6,250	6,250	0	
8	AEP Holdings	(10,000)	0	0	(10,000)	
9	AEP Energy Services	0	272	272	0	
10	AEP Wind Holding Co	0	12	12	0	
11	Various Transmission	0	25,396,480	24,494,980	901,500	
12	AEP Transmission	7,320,636	1,833,904	9,103,925	50,615	
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
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30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	146,858,213	4,327,016,392	4,294,879,444	178,995,161	210,896

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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)	85,318,798	51,129,732	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	2,232,093	1,849,711	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	35,997,777	52,245,285	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	110,338,529	92,255,701	Electric
8	Transmission Plant (Estimated)	1,085,092	529,602	Electric
9	Distribution Plant (Estimated)			Electric
10	Regional Transmission and Market Operation Plant (Estimated)	942,292	1,083,329	
11	Assigned to - Other (provide details in footnote)	135,873	124,743	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	148,499,563	146,238,660	Electric
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	3,256,501	3,057,394	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)	239,306,955	202,275,497	

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 (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2011

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**	85,318,798	2,394,968	82,935,570
2	**Received during year**	247,995,977	6,347,640	241,929,883
3	**TOTAL**	333,314,775	8,742,608	324,865,453
4	**Used during year (specify department)**			
5	Electric Generation	279,737,255	6,528,547	274,692,305
6	Storage Pile Adjustment	2,447,788	56,389	2,447,788
7				
8				
9				
10				
11				
12				
13				
14				
15	**Sold or transferred**			
16	**TOTAL DISPOSED OF**	282,185,043	6,584,936	277,140,093
17	**BALANCE END OF YEAR**	**51,129,732**	2,157,672	47,725,360

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, 2011

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.
27,139	2,383,228					1
46,446	6,066,094					2
73,585	8,449,322					3
						4
43,894	5,044,950					5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
43,894	5,044,950	0	0	0	0	16
29,691	**3,404,372**	**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 2011/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		2012	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	277,754.00	22,929,689	91,640.00	3,259,922
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Appalachian Power Company	11,759.00	4,040,598		
10	Ohio Power Company	16,092.00	9,258,143		
11					
12					
13					
14					
15	Total	27,851.00	13,298,741		
16					
17	Relinquished During Year:				
18	Charges to Account 509	99,377.00	12,727,902		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	AEP System Pool	2,334.00	909,367		
23					
24					
25					
26					
27					
28	Total	2,334.00	909,367		
29	Balance-End of Year	203,894.00	22,591,161	91,640.00	3,259,922
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	1,164.00		1,976.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	1,164.00			
40	Balance-End of Year			1,976.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)		3,424		
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 2011/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.

2013		2014		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
96,129.00	3,046,551	111,535.00	6,123,561	2,104,310.00		2,681,368.00	35,359,723	1
								2
								3
				81,376.00		81,376.00		4
								5
								6
								7
								8
						11,759.00	4,040,598	9
						16,092.00	9,258,143	10
								11
								12
								13
								14
						27,851.00	13,298,741	15
								16
								17
			1,321,600			99,377.00	14,049,502	18
								19
								20
								21
						2,334.00	909,367	22
								23
								24
								25
								26
								27
						2,334.00	909,367	28
96,129.00	3,046,551	111,535.00	4,801,961	2,185,686.00		2,688,884.00	33,699,595	29
								30
								31
								32
								33
								34
								35
1,170.00		357.00		56,199.00		60,866.00		36
				714.00		714.00		37
								38
				357.00		1,521.00		39
1,170.00		357.00		56,556.00		60,059.00		40
								41
								42
					60		3,484	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 2011/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		2012	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	28,445.00	3,645,698	23,740.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Purchase Accrual	2,715.00	190,049		
10	Auburndale Power Partners	100.00	5,750		
11	Buckeye Power Inc.	1,460.00	1,800,718		
12	Cogen Technologies Linden	350.00	24,500		
13	Dairyland Power Coop	300.00	21,000		
14	Other	1,501.00	371,844		
15	Total	6,426.00	2,413,861		
16					
17	Relinquished During Year:				
18	Charges to Account 509	32,591.00	5,282,894	1,175.00	
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	2,280.00	776,665	22,565.00	
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 2011/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.

2013		2014		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
23,740.00		23,740.00				99,665.00	3,645,698	1
								2
								3
								4
								5
								6
								7
								8
						2,715.00	190,049	9
						100.00	5,750	10
						1,460.00	1,800,718	11
						350.00	24,500	12
						300.00	21,000	13
						1,501.00	371,844	14
						6,426.00	2,413,861	15
								16
								17
						33,766.00	5,282,894	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
23,740.00		23,740.00				72,325.00	776,665	29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

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

	No.	Amount
Buckeye Power Company	426	309,281
Element Markets LLC	250	8,125
Lower Colorado River Authority	250	18,750
National Grid Generation LLC	175	12,688
Union Electric Company	400	23,000
Total	1,501	371,844

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, 2011

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	Deferred Cook Unit 1 Fire Expenses	63,808,849
2	Energy Insurance Services	5,966,524
3	Misc External Insurance	3,200,129
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25	TOTAL	**72,975,502**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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 #V3-015 Keystone 345KV	3,004	186	4,284	186
3	PJM #T142 E. Lima-Marysville 345KV	560	186		
4	PJM #S71 Bluff Point 138KV	3,659	186	105,000	186
5	PJM #U3-002 Mullin Greentown 138KV	142	186	145	186
6	PJM #R60 Robison Park-Convoy 345KV	3,865	186	62,459	186
7	PJM #R03 Adams-Allen 138KV	4,408	186		
8	PJM #T183 Olive-Dequine 345KV	2,910	186	2,910	186
9	PJM #T126 Olive-Dequine 345KV	206	186	206	186
10	PJM #U2-092 Delaware 138KV	42	186	3,000	186
11	PJM #V4-021 Keystone 345KV	363	186	363	186
12	PJM #W2-044 Meridian 138KV			303	186
13	PJM #W3-024 Columbia 138KV	19,400	186	19,428	186
14	PJM #V1-012 Haviland 138KV	5,794	186	5,601	186
15	PJM #W4-008 Madison-Tanners 138KV	12,974	186	12,974	186
16	PJM #X1-020 Dumont-Greentown 765KV	1,875	186	1,875	186
17					
18					
19					
20					
21	**Generation Studies**				
22					
23	NONE				
24					
25					
26					
27					
28					
29					
30					
31					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	8,967,555	1,040,007	228	870,443	9,137,119
2						
3	Cook Plant Refueling Levelization	53,794,954	46,171,396	various	59,415,631	40,550,719
4						
5	VEBA Trust Contributions	339,729		926	177,250	162,479
6	Amort 12/2010 - 11/2012					
7	Per MPSC Case U-16180					
8						
9	SFAS 106 Post Retirement Benefits	1,857,369		926	1,515,222	342,147
10	Amort 3/2009 - 3/2012					
11	Per IURC Cause Order #43306					
12						
13	Unamortized Loss on Reacquired Debt	2,483,440		428	206,953	2,276,487
14	Amort 1/1995 - 12/2022					
15						
16	River Transportation Selling Price Variance	338,876	7,412,110	254	5,851,813	1,899,173
17						
18	Unrealized Loss on Forward Commitments	186,380	603,097,188	various	603,283,568	
19						
20	Deregulation Implementation	6,766,991	538,716	407,920	2,625,379	4,680,328
21						
22						
23						
24	Asset Retirement Obligations	2,699,584	807,995	403,411	111,812	3,395,767
25	Amortz 3/2009 - 3/2020					
26	Per IURC Cause Order #43306					
27						
28	Indiana Rate Case expenses	194,767		928	158,889	35,878
29	Amortz 3/2009 - 3/2012					
30	Per IURC Cause Order #43306					
31						
32	Michigan Rate Case expenses	235,020		928	122,619	112,401
33	Amort 12/2010 - 11/2012					
34	Per MPSC Case U-16180					
35						
36	Deferred Environmental Compliance Costs	1,102,935	403,607	509	1,506,542	
37						
38	Deferral of Michigan portion PJM Fees	7,078,335	307,754	561,575	4,000,798	3,385,291
39	Amort 12/2010 - 11/2012					
40	Per MPSC Case U-16180					
41						
42	Deferred Equity Carrying Charges	(60,164)				-60,164
43						
44	TOTAL	585,007,876	1,161,011,334		1,115,876,246	630,142,964

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	Deferred RTO Equity Carrying Charges	(596,471)	88,116			-508,355
2	Amort 1/2005 - 12/2019					
3						
4	BridgeCo Transmission Org Funding	1,064,255		407	81,236	983,019
5	Amort 1/2005 - 12/2019					
6	FERC Docket No. AC04-101-000					
7						
8	PJM Integration Payments	1,677,268		407	374,950	1,302,318
9	Amort 1/2005 - 12/2014					
10	FERC Docket No. EL05-74-000					
11						
12	Other PJM Integration	990,548		407	75,610	914,938
13	Amort 1/2005 - 12/2019					
14	FERC Docket No. AC04-101-000					
15						
16	Carrying Charges - RTO Startup Costs	689,797	263,727	407	351,699	601,825
17	Amort 1/2005 - 12/2019					
18	FERC Docket No. AC04-101-000					
19	& FERC Docket No. EL05-74-000					
20						
21	Alliance RTO Deferred Expense	611,188		407	46,653	564,535
22	Amort 1/2005 - 12/2019					
23	FERC Docket No. AC04-101-000					
24						
25	Unrecovered Fuel Cost	8,558,667	38,001,745	various	37,589,072	8,971,340
26						
27	SFAS 158 Employer Accounting for Defined	268,079,875	292,143,661	various	268,831,499	291,392,037
28	Benefit Pension & Other Postretirement Plans					
29						
30	Off-System Sales Margin Sharing	13,091,412	20,292,304	447	33,383,716	
31						
32	NSR Consent Decree Settlement Expenses	1,150,549		506	938,604	211,945
33	Amort 3/2009 - 3/2012					
34	Per IURC Cause Order #43306					
35						
36	DSM Energy Optimization Program	287	1,489,408	421	103,005	1,386,690
37	Under-recovered costs					
38						
39	Indiana Clean Coal Technology Rider	1,222,758	372,869	421	1,478,582	117,045
40	Carrying Charges					
41	Per IURC Cause Order #43636					
42						
43						
44	TOTAL	585,007,876	1,161,011,334		1,115,876,246	630,142,964

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	Deferred Nuclear Decommisioning Study Costs	11,667		524	4,000	7,667
2	Amort 12/2010 - 11/2013					
3	Per MPSC Case U-16180					
4						
5	Enhanced post-9/11 Cook Plant Security Costs	582,340		524	118,442	463,898
6	Amort 12/2010 - 11/2015					
7	Per MPSC Case U-16180					
8						
9	Deferred Severance Costs	6,216,632		various	1,264,399	4,952,233
10	Amort 12/2010 - 11/2015					
11	Per MPSC Case U-16180					
12						
13	SFAS 109 Deferred FIT	116,023,358	77,751,187	various	78,929,191	114,845,354
14						
15	SFAS 109 Deferred SIT	79,647,975	38,064,797	283	10,538,214	107,174,558
16						
17	Carbon Capture & Storage Project FEED		2,900,781	107	1,220,455	1,680,326
18	Study Costs					
19						
20	Under Recovery of PJM Expenses		18,360,884			18,360,884
21						
22	City of Fort Wayne Right to Serve Settlement		5,000,000	426	700,000	4,300,000
23						
24	City of Fort Wayne - Carry Charge		603,082			603,082
25						
26	City of Ft. Wayne Betterments/Generation Settlement		5,900,000			5,900,000
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	585,007,876	1,161,011,334		1,115,876,246	630,142,964

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	32,047,716	53,712,388	408	51,833,949	33,926,155
2						
3	Property Taxes - Capital Leases	181,669	674,689	408	750,187	106,171
4						
5	Labor Accruals	3,176	30,077	various	9,959	23,294
6						
7	Agency Fees, Factored Accts Rec	2,467,311	27,125,525	various	27,160,903	2,431,933
8						
9	River Transport Division	63,695	180,301,933	various	180,602,906	-237,278
10						
11	Deferred Rate Case expense		1,600,219	182.3	1,147,834	452,385
12						
13	Unamortized Credit Line Fees	715,890	1,726,016	431	946,569	1,495,337
14						
15	Allowances	844	4,983,460	158,509	4,982,912	1,392
16						
17	Defd Non-taxable Leased Assets	402,708	193,590	146	517,741	78,557
18						
19	Misc Deferrals <$100,000		817			817
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
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39						
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42						
43						
44						
45						
46						
47	Misc. Work in Progress	386,145				49,516
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	36,269,154				38,328,279

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, 2011

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	337,059,999	87,478	17,620,034
3	Reg Liability - SFAS 143 - ARO	123,791,023	32,758,600	40,974,112
4	Capitalized Cook Costs	33,937,163	6,296,815	0
5	Capitalized Interest Expense	25,506,465	1,884,080	2,870,013
6	SFAS 158	93,827,895	4,511,474	12,670,731
7	Other (see pp. 234.1A-234.1B)	68,693,631	77,255,098	61,412,950
8	TOTAL (Account 190) (Enter total of lines 2 thru 7)	682,816,176	122,793,545	135,547,840
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)	62,974,785	0	
18	TOTAL (Account 190) *(Enter total of lines 8, 16 & 17)*	745,790,961	**122,793,545**	**135,547,840**
19	Classification of Total:			
20	Federal Income Tax	746,021,533	122,793,545	135,547,840
21	State Income Tax	(230,572)		
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	3,910,151	5,442,320
Non-Utility 190.2 State	-230,572	-576,653
SFAS 133	5,399,467	8,853,395
SFAS 87	5,841,434	6,087,799
SFAS 109	48,054,305	55,027,819
Total	62,974,785	74,834,680

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, 2011	

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
						354,592,555	2
						132,006,535	3
						27,640,348	4
						26,492,398	5
						101,987,152	6
		236	4,433,884	236	787,002	56,498,365	7
0	0		4,433,884		787,002	699,217,353	8
							9
							10
							11
							12
							13
							14
						0	15
0	0		0		0	0	16
4,334,691	5,520,779	Various	29,742,518	Various	19,068,711	74,834,680	17
4,334,691	5,520,779		34,176,402		19,855,713	774,052,033	18
							19
3,742,462	5,274,631		34,176,402		19,855,713	774,628,686	20
592,229	246,148					(576,653)	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, 2011

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	7,790,298	2,167,863	85,584
3	Provisions for Loss Trading Credit Risk	344,912	275,702	416,430
4	Property Tax Deferrals	1,504,291	3,357,489	844,188
5	Installation Allowances Capitalized	11,137	0	3,780
6	Pre 04/83 Nuclear Fuel Cost	14,468,912	57,529	18,687
7	Nuclear Decommissioning	14,435,958	14,882,832	0
8	IRS Settlements	1,912,933	7,199,047	2,074,617
9	Deferred Gain Sale of Rockport Unit 2	15,038,715	1,297,351	37,068
10	Amortization of Step Up ITC Rockport Unit 2	4,771,582	397,583	0
11	Accrued Vacation Pay	4,324,468	915,365	1,286,568
12	Accrued Severance Benefits	397,463	390,308	14,111
13	Accrued Incentive Plans	6,542,678	6,914,307	9,683,248
14	Book Provision for Uncollectible Debt	592,242	250,623	270,713
15	Mark to Market Gain/Loss	3,746,114	9,128,147	13,603,052
16	Capitalized Software Tax	13,648	696	3,276
17	Revenue Refunds	1,852,152	1,088,242	488,658
18	SFAS 112 Post Employment Benefits	2,070,733	100,007	364,002
19				
19	Accrued Income Tax and Interest	(1,678,540)	1,751,419	3,221,768
20	Accrued Pension Expense	(30,867,137)	14,365,046	3,753,915
21	SFAS 106 Post Retirement Benefits	8,802,841	619,037	1,406,112
22	Accrued SIT	(15,251)	350,482	164,718
23	Other Miscellaneous	12,633,482	11,746,023	23,672,455
24	Total Other	68,693,631	77,255,098	61,412,950
25				
26				
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, 2011

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
						5,708,019	2
						485,640	3
						(1,009,010)	4
						14,917	5
						14,430,070	6
						(446,874)	7
						(3,211,497)	8
						13,778,432	9
						4,373,999	10
						4,695,671	11
						21,266	12
						9,311,619	13
						612,332	14
						8,221,019	15
						16,228	16
						1,252,568	17
						2,334,728	18
						0	18
						(208,191)	19
						(41,478,268)	20
						9,589,916	21
						(201,015)	22
		236	4,433,884	236	787,002	28,206,796	23
						56,498,365	24
							25
							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, 2011

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	7.35% Series First Mortgage Bonds due 10/2023	5/2003	15,000,000	(383,698)
15	This debt was replaced by the following issuances:			
16	6.375% Senior Unsecured Note due 11/2012			
17	6.00% Senior Unsecured Note due 12/2032			
18				
19	8.5% Series First Mortgage Bonds due 12/2022	5/2003	75,000,000	(2,353,464)
20	This debt was replaced by the following issuances:			
21	6.375% Senior Unsecured Note due 11/2012			
22	6.00% Senior Unsecured Note due 12/2032			
23				
24	7.0% Pollution Control Revenue Bonds	11/2003	25,000,000	(600,619)
25	Lawrenceburg, IN Series Due 4/2015			
26	Replaced by 2.625% Lawrenceburg Bonds Due 10/2019			
27	Loss being amortized over life of replacement debt			
28				
29				
30	5.9% Pollution Control Revenue Bonds, due 11/2021	11/2004	52,000,000	(1,089,232)
31	City of Lawrenceberg, Indiana. (Replaced by VAR%			
32	Lawrenceberg, IN Bonds due 11/2021.)			
33				
34	9-1/4% Pollution Control Revenue Bonds, due 8/2014	8/1995	50,000,000	(3,928,658)
35	City of Rockport, Indiana.			
36	Replaced by 6.55% Rockport Bonds due 6/2025			
37	Replaced 5/06 by VAR% Rockport Bonds Due 6/2025,			
38	with $500,000 premium paid for early redemption			
39				
40	VAR% Pollution Control Revenue Bonds, due 8/2014	8/1995	50,000,000	(785,290)
41	City of Rockport, Indiana.			
42	Replaced by VAR% Rockport Bonds due 6/2025			
43				
44	7.6% Pollution Control Revenue Bonds	11/2003	40,000,000	(338,620)
45	Rockport, IN Series Due 3/2016			
46	Replaced by 2.625% Rockport IN Bonds Due 4/2025			
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, 2011

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.
1,102,979		84,304	1,018,675	1
				2
				3
1,555,557		118,144	1,437,413	4
				5
				6
				7
				8
				9
				10
				11
200,742		32,999	167,743	12
				13
				14
				15
28,138		15,348	12,790	16
				17
				18
				19
				20
172,587		94,138	78,449	21
				22
				23
				24
				25
				26
505,942		57,822	448,120	27
				28
				29
923,917		85,285	838,632	30
				31
				32
				33
2,031,636		140,923	1,890,713	34
				35
				36
				37
				38
				39
378,427		26,249	352,178	40
				41
				42
				43
801,554		56,249	745,305	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, 2011

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	8.0% Junior Subordinated Debentures due 3/2026	5/2003	40,000,000	(1,291,678)
2	This debt was replaced by the following issuances:			
3	6.375% Senior Unsecured Note due 11/2012			
4	6.00% Senior Unsecured Note due 12/2032			
5				
6	7.6% Junior Subordinated Debentures due 6/2038	5/2003	125,000,000	(2,911,019)
7	This debt was replaced by the following issuances:			
8	6.375% Senior Unsecured Note due 11/2012			
9	6.00% Senior Unsecured Note due 12/2032			
10				
11	9.00% Pref Stock Subject to Mandatory Redemption	4/1993	40,000,000	(896,000)
12	8.60% Pref Stock Subject to Mandatory Redemption	12/1993	40,000,000	(864,000)
13	8.68% Pref Stock Subject to Mandatory Redemption	1/1994	30,000,000	(540,000)
14	7.76% Pref Stock Subject to Mandatory Redemption	3/1994	35,000,000	(798,000)
15	6.875% Pref Stock Subject to Mandatory Redemption	1/2005	15,750,000	
16	5.90% Pref Stock Subject to Mandatory Redemption	1/2005	13,200,000	(861,392)
17	6.25% Pref Stock Subject to Mandatory Redemption	1/2005	19,250,000	
18	6.30% Pref Stock Subject to Mandatory Redemption	1/2005	13,245,000	
19	(Balance transferred from FERC Acct 210 to 189)			
20				
21	VAR % Pollution Control Revenue Bonds, due 10/2019	5/2008	25,000,000	(323,600)
22	Series F Lawrenceburg			
23	Remarketed as Series I VAR%			(134,515)
24				
25				
26	VAR % Pollution Control Revenue Bonds, due 11/2021	5/2008	52,000,000	(1,013,352)
27	Series G Lawrenceburg			
28	Remarketed as Series H VAR%			(261,800)
29				
30	Early Redemption of $150M Series D Senior Unsecured Note			
31	Orginal Maturity Date of December 31, 2032			
32	Redeemed October 15, 2010			
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, 2011

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.
94,723	0	51,667	43,056	1
				2
				3
				4
				5
213,475	0	116,440	97,035	6
				7
				8
				9
				10
				11
				12
				13
368,543	0	28,152	340,391	14
				15
				16
				17
				18
				19
				20
249,837	0	28,553	221,284	21
				22
-	134,515	11,754	122,761	23
				24
				25
818,232	0	75,528	742,704	26
				27
-	261,800	18,554	243,246	28
				29
6,577,160	0	298,962	6,278,198	30
				31
				32
				33
				34
				35
16,023,450	**396,315**	**1,341,071**	**15,078,694**	36
				37
(21,827)	1,712	-	(20,115)	38
				39
				40
				41
(21,827)	**1,712**	**-**	**(20,115)**	42
				43
16,001,623	**398,027**	**1,341,071**	**15,058,579**	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 2011/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				
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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 2011/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				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
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						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 31,2011

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			
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36			
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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 2011/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 2011	972,666,991
3		
4	Subtotal Account 208	972,666,991
5		
6	Gain on reacquired capital stock (Account 210)	
7	Beginning balance on all series	434,696
8		
9	Series 4.12% Loss on redemption of all remaining shares	-27,039
10	Series 4.125% Loss on redemption of all remaining shares	-258,278
11	Series 4.56% Loss on redemption of all remaining shares	-28,824
12		
13	Subtotal Account 210	120,555
14		
15	Miscellaneous paid-in capital (Account 211)	
16	Amounts recorded in connection with:	
17	Merger of Indiana Service Corporation with respondent in 1948 as	
18	subsequently adjusted on December 31, 1948	1,002,503
19		
20	Acquisition of Citizen's Heat, Light and Power Company by	
21	respondent in 1954	10,687
22		
23	Merger of Michigan Power Company with respondent in 1992.	2,861,068
24	Subtotal Account 211	3,874,258
25		
26		
27		
28		
29		
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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, 2011

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 2011

Series	Due Date	Principal Amount	Date Retired

See page 253 for details related to the 2011 redemption of all shares of preferred stock.

2. Securities issued during 2011

Series	Due Date	Principal Amount	Date Issued
None			

3. Securities Remarketed during 2011

Series	Due Date	Principal Amount	Date Remarketed
$52MM Pollution Control Bonds - Series F Remarketed to Series H - VRDN	11/1/2021	52,000,000	3/16/2011
$25MM Pollution Control Bonds - Series G Remarketed to Series I - VRDN	10/1/2019	25,000,000	3/24/2011

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	NONE		
3	SUBTOTAL - Account 222-Reacq PCRBs		
4			
5	Account 223 - Advances From Associated Companies		
6	SUBTOTAL - Account 223-Advances From Assoc Co		
7			
8	Account 224 - Other Long Term Debt		
9	Spent Nuclear Fuel Disposal Costs Prior		
10	To April 7, 1983 - Basic Fee Assessment & Interest		
11			
12	Pollution Control Revenue Bonds		
13	Lawrenceburg, IN		
14	Series I - Weekly Auction Rate	25,000,000	178,919
15			103,287
16			
17	Series H - Weekly Auction Rate	52,000,000	331,889
18			172,181
19	Rockport, IN		
20	Series D - 5.25% Fixed Rate	40,000,000	1,157,720
21			
22	Series 2002 A - 4.625% Fixed Rate	50,000,000	296,785
23			325,000 D
24			382,272
25			136,351 D
26			444,593
27			74,250
28			74,250
29			74,250
30			74,250
31	Series 2009 A - 6.25% Fixed Rate	50,000,000	353,976
32	per IURC Order #43445, approved 4/9/08		
33	TOTAL	1,568,802,388	21,029,994

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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)			
						1
						2
						3
						4
						5
						6
						7
						8
						9
				265,065,015		10
						11
						12
						13
5/22/2008	10/1/2019	5/22/2008	10/1/2019	25,000,000	38,267	14
3/24/2011	10/1/2019	3/24/2011	3/24/2013			15
						16
5/20/2008	11/1/2021	5/20/2008	11/1/2021	52,000,000	99,199	17
3/16/2011	11/1/2021	3/16/2011	3/16/2013			18
						19
4/25/2008	4/1/2025	4/25/2008	4/1/2025	40,000,000	2,100,000	20
						21
8/1/1985	6/1/2025	8/1/1985	6/1/2025	50,000,000	2,312,500	22
						23
6/1/2002	6/1/2007	6/1/2002	6/1/2007			24
						25
6/1/2007	6/1/2025	6/1/2007	6/1/2025			26
		6/1/2008	5/31/2009			27
		6/1/2009	5/31/2010			28
		6/1/2010	5/31/2011			29
		6/1/2011	5/31/2012			30
3/26/2009	6/1/2025	4/1/2009	5/31/2014	50,000,000	3,125,000	31
						32
				1,827,992,520	92,125,153	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 2011/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	Bonds subj to mand tender for purchase (puttable) on 6/2/14		
2			
3	Series 2009 B - 6.25% Fixed Rate	50,000,000	353,976
4	per IURC Order #43445, approved 4/9/08		
5	Bonds subj to mand tender for purchase (puttable) on 6/2/14		
6	Brokerage Fees on Auction Rate Notes		
7			
8	Senior Unsecured Notes		
9	Series E - 6.375% Fixed Rate	100,000,000	732,025
10			119,000 D
11			
12			
13	Series F - 5.05% Fixed Rate	175,000,000	1,302,944
14			637,000 D
15			
16	Amortization of Cash Flow Hedge on 5.05% SUN		
17			
18	Series G - 5.65% Fixed Rate	125,000,000	906,746
19			176,250 D
20			
21	Amortization of Cash Flow Hedge on 5.65% SUN		
22			
23	Series H - 6.05% Fixed Rate	400,000,000	3,815,383
24			2,272,000 D
25			
26	Amortization of Cash Flow Hedges on 6.05% SUN		
27			
28	Series I - 7.00% Fixed Rate	475,000,000	3,333,197
29			3,201,500 D
30	Fort Wayne Settlement	26,802,388	
31			
32	SUBTOTAL - Acct 224 - Other Long Term Debt	1,568,802,388	21,029,994
33	TOTAL	1,568,802,388	21,029,994

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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)			
						1
						2
3/26/2009	6/1/2025	4/1/2009	5/31/2014	50,000,000	3,125,000	3
						4
						5
					130,220	6
						7
						8
11/22/2002	11/1/2012	11/22/2002	11/1/2012	100,000,000	6,375,000	9
						10
						11
						12
11/16/2004	11/15/2014	11/16/2004	11/15/2014	175,000,000	8,837,500	13
						14
						15
		11/16/2004	11/15/2014		877,839	16
						17
12/7/2005	12/1/2015	12/1/2005	11/30/2015	125,000,000	7,062,500	18
						19
						20
		12/1/2005	11/30/2015		-383,570	21
						22
11/14/2006	3/15/2037	11/14/2006	3/15/2037	400,000,000	24,200,000	23
						24
						25
		11/14/2006	2/28/2037		975,698	26
						27
1/15/2009	3/15/2019	1/1/2009	2/28/2019	475,000,000	33,250,000	28
						29
3/1/2010	2/28/2025	3/1/2010	2/28/2025	20,927,505		30
						31
				1,827,992,520	92,125,153	32
				1,827,992,520	92,125,153	33

Schedule Page: 256 Line No.: 14 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.: 17 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.: 20 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.: 22 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 and June 2011 each time costing $74,250 & to be fully amortized over each policy period.

Schedule Page: 256 Line No.: 31 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 Line No.: 31 Column: e

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

Schedule Page: 256.1 Line No.: 3 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.: 3 Column: e

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

Schedule Page: 256.1 Line No.: 28 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.

FOOTNOTE DATA

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

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

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

Interest expense amounting to $315,710 was recorded in account 431 from Oct 2011 - Dec 2011, related to the Fort Wayne Settlement and payments.

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2011

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	48,104,996	8,402,887,797	8,354,782,801	0	24,245
3	SUBTOTAL	48,104,996	8,402,887,797	8,354,782,801	0	24,245
4	Account 234					
5	AEP Transmission Companies - Various	0	9,919,376	10,128,902	209,526	
6	AEP Holding	(10,000)	0	0	(10,000)	
7	AEP Resources	0	0	28	28	
8	AEP Generating Company	28,189,606	259,114,603	257,057,097	26,132,100	
9	AEP Memco, LLC	10,253,171	81,315,081	78,624,932	7,563,022	
10	AEP Pro Serv, Inc.	(0)	5,072	5,072	(0)	
11	AEP Service Corporation	13,329,363	191,761,871	192,207,422	13,774,914	
12	AEP System Pool (AEPSC)	24,882,421	659,736,858	651,726,420	16,871,983	
13	AEP Transmission	3,505,973	3,618,652	112,679	0	
14	AEP Texas Central Company	7,129	284,169	246,340	(30,700)	
15	AEP Texas North Company	847	1,471,464	1,470,145	(472)	
16	AEP Energy Services	0	272	272	0	
17	AEP Coal, Inc	0	1,209	1,209	0	
18	AEP T&D Services	0	247,244	247,244	0	
19	AEP Utilities, Inc	0	189,405	189,405	0	
20	AEP Utility Funding LLC	171,974	246,577	131,236	56,633	
21	AEPES Power Trading	15,438	137,922	122,484	(0)	
22	American Electric Power Co	1,747,628	613,060,828	613,255,514	1,942,314	
23	Appalachian Power Co	12,888,787	28,725,284	20,188,257	4,351,760	
24	Blackhawk Coal Company	49,991	582,744	591,694	58,941	
25	Cardinal Operating Company	4,313	44,574	44,574	4,313	
26	Conesville Coal Prep Co	0	10	10	0	
27	Cook Coal Terminal	2,764,324	39,930,342	38,381,293	1,215,275	
28	CSW Energy, Inc	0	284	284	0	
29	Dolet Hills Lignite Co	0	55,626	55,626	0	
30	Energy Insurance Services	0	1,193,741	1,193,741	0	
31	Franklin Real Estate Company	0	24,368	24,368	0	
32	Indiana Franklin Realty, Inc	(0)	209,152	209,152	(0)	
33	Kentucky Power Co	2,919	640,326	647,685	10,278	
34	Kingsport Power Co	0	8,840	8,840	0	
35	Ohio Power Co	7,448,705	43,656,246	45,744,553	9,537,012	
36	Public Service Co of OK	14,647	1,631,803	978,819	(638,337)	
37	Public Liability	0	243,121	243,121	0	
38	Southwestern Electric Power Co	(10,837)	5,014,730	5,130,545	104,978	
39	United Sciences Testing, Inc	0	94,279	94,279	0	
40	Wheeling Power Co	0	8,615	8,615	0	
41	SUBTOTAL	105,256,398	1,943,174,687	1,919,071,857	81,153,568	0
42						
43	TOTAL	153,361,394	10,346,062,484	10,273,854,658	81,153,568	24,245

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, 2011

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)	230,371,615
2	Allocations:	
3	Net Other Income and Deductions	10,318,020
4	Interest Charges	91,015,751
5	Net income for the year (page 117 line 78)	149,673,884
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	(131,843,719)

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, 2011

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.
230,371,615		1
		2
10,318,020		3
91,015,751		4
		5
		6
		7
		8
		9
		10
		11
		12
		13
		14
		15
		16
		17
		18
		19
		20
		21
		22
		23
		24
		25
(131,843,719)		26

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, 2011

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	149,674
Federal Income Taxes	53,745
State and Local Income Taxes	(2,118)
PreTax Book Income	201,301
Increase (Decrease) in Taxable Income resuliting from:	
Allowance for Funds Used During Constructionand /Interest Capitalized	(14,836)
Amortization of Deferred Book Gain - Rockport Unit 1 Sale (562B)	(3,707)
Book Accruals and Deferrals	(35,678)
Book/Tax Unit Property Adj	(40,769)
Deferred Fuel Cost	(413)
Emission Allowances Net	12,887
Equity in Earnings Subsidiary Companies	42
Excess Tax vs Book Depreciation	(209,432)
Market to Market	20,520
Nuclear Book Deferred Cost	13,244
Nuclear Decommissoning Costs	(75,832)
Nuclear Fuel Adjustments	(34,660)
Nuclear Fuel Disposal Costs	(4,112)
Pollutions Control	48
Property Tax	199
Removal Costs	(14,546)
Relocation Costs	(2,100)
Revenue Refunds	(2,307)
SFAS 143 - ARO	75,550
Tax Accruals/Tax Deferrals	(12,577)
Other (Net)	99
Federal Tax Net Income - Estimated Current Year Taxable Income	(127,079)
(Separate Return Basis)	
Current State Income Taxes	4,765
Federal Taxable Income	(131,844)
Computation Tax*	
Federal Income Tax on Current Year Taxable Income (Separate Return Basis) at Statutory Rate of 35%	(46,145)
Adjustment due to System Consolidation	-
Estimated Taxes Currently Payable b	(46,145)
Tax Provision Adjustment	3,853
Audit Settlement Adjustment	(14,203)
R&D Credit	216
Adjustment of Prior Years Accruals(Net)	(34,657)
Estimated Current Year Federal Income Taxes (Net)	(90,936)

(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 2011 System Federal income taxes will not be available until the consolidated Federal income tax return is completed and filed by September 2012. The actual allocation of the System consolidated Federal income tax to the members of the consolidated group will not be available until after the Consolidated Federal Income Tax is filed.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	-37,499,534		-81,803,149	-98,400,978	3,643,139
3	FICA - 2011	2,440,581		17,245,688	17,054,296	
4	UNEMPLOYMENT - 2011	35,948		290,872	162,024	-3
5	EXCISE TAX - 2010	375,363		4,400	379,763	
6	EXCISE TAX - 2011			1,624,109	1,180,706	
7	SUBTOTAL Federal	-34,647,642		-62,638,080	-79,624,189	3,643,136
8						
9	STATE OF INDIANA:					
10	INCOME 2010	-12,638,693		-6,421,842	-19,060,535	
11	INCOME 2011			2,389,193	12,408,063	
12	UNEMPLOYMENT IN - 2011	20,763		51,282	62,106	
13	UTIL RECEIPTS TAX - 2010			11,660	11,660	
14	UTIL RECEIPTS TAX - 2011			14,943,000	14,943,000	
15	INDIANA LICENSE TAX			22	22	
16	SALES & USE TAX - 2010	215,527		116,024	331,551	
17	SALES & USE TAX - 2011			4,350,528	3,479,523	
18						
19	PUBLI SERV COMM-2010		282,628	565,256	282,628	
20	PUBLI SERV COMM-2011			625,647	938,470	
21	REAL & PERS PROP-2006			129	129	
22	REAL & PERS PROP-2008			-13,650	-13,650	
23	REAL & PERS PROP-2009	-9		-12,235	-12,244	
24	REAL & PERS PROP-2010	19,546,600		133,135	19,679,735	
25	REAL & PERS PROP-2011			20,264,760	345	
26	PERS PROP LEASED-2009					
27	PERS PROP LEASED-2010	477,400		-155,340	322,060	
28	PERS PROP LEASED-2011			337,700		
29	REAL PROP LEASED-2009	-9,444		9,444		
30	REAL PROP LEASED-2010	62,513		-95,187	-32,674	
31	REAL PROP LEASED-2011			777,487	557,412	
32	SUBTOTAL Indiana	7,674,657	282,628	37,877,013	33,897,601	
33						
34						
35						
36						
37						
38	STATE OF KENTUCKY:					
39	REAL & PERS PROP-2009	-14,715		14,715		
40	REAL & PERS PROP-2011				26,140	
41	TOTAL	8,848,773	1,165,647	14,952,028	-12,549,589	3,643,136

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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
-17,258,566		-76,271,102			-1,679,422	2
2,631,973		11,739,967			5,505,721	3
164,793		325,003			-34,131	4
					4,400	5
443,403		11,576			1,612,533	6
-14,018,397		-64,194,556			5,409,101	7
						8
						9
		-6,444,921			23,079	10
-10,018,870		2,362,010			27,183	11
9,939		35,341			15,941	12
		11,660				13
		14,943,000				14
		22				15
					116,024	16
871,005					4,350,528	17
						18
		565,256				19
	312,823	625,647				20
		129				21
		-13,650				22
		-12,235				23
		3,342,263			-3,209,128	24
20,264,415		16,575,260			3,689,500	25
						26
		-75,780			-79,560	27
337,700		281,419			56,281	28
					9,444	29
					-95,187	30
220,075					777,487	31
11,684,264	312,823	32,195,421			5,681,592	32
						33
						34
						35
						36
						37
						38
		14,715				39
-26,140						40
39,814,135	986,256	-1,117,711			15,504,331	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 2011/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	KY INCOME 2010	-640,931		-82,419	-723,350	
2	KY INCOME 2011			83,863	893,350	
3	Subtotal Kentucky	-655,646		16,159	196,140	
4	STATE OF MICHIGAN:					
5	MI INCOME 2010	284,069		-390,866	-106,797	
6	MI INCOME 2011			1,474,180	3,419,047	
7	MI SBT 2007				6,144	
8	MI CITIES	-1,279				
9	UNEMPLOYMENT - 2011	64,706		258,904	273,569	
10	PUBL SERV COMM'S-2010		126,093	502,811	376,718	
11	PUBL SERV COMM'S-2011			127,059	127,059	
12	USE TAX-2010	63,324	248,073	10,048	-174,701	
13	USE TAX - 2011			1,055,394	1,052,488	
14	USE TAX-REFUND 2009			-1,191,853	-1,191,853	
15	SALES TAX - 2010		508,853		-508,853	
16	SALES TAX - 2011				562,130	
17	REAL & PERS PROP-2008	-3,268		179	-3,089	
18	REAL & PERS PROP-2009	6,350,143		949,796	7,299,939	
19	REAL & PERS PROP-2010	28,565,486		102,531	21,463,032	
20	REAL & PERS PROP-2011			30,430,029		
21	PERS PROP LEASED-2010	102,109		-66,385	24,590	
22	PERS PROP LEASED-2011			49,891		
23	REAL PROP LEASED-2008					
24	REAL PROP LEASED-2009	241,400		-18,879	222,521	
25	REAL PROP LEASED-2010			223,639	185,929	
26	SUBTOTAL Michigan	35,666,690	883,019	33,516,478	33,027,873	
27						
28	DE License Tax					
29	SUBTOTAL DELAWARE					
30						
31						
32						
33						
34						
35						
36						
37						
38	STATE OF WEST VIRGINIA:					
39	LICENSE TAX			55	55	
40	WEST VA INC TAX-2009			-413,012		
41	TOTAL	8,848,773	1,165,647	14,952,028	-12,549,589	3,643,136

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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)	
		-39,096			-43,323	1
-809,487		83,379			484	2
-835,627		58,998			-42,839	3
						4
		-521,310			130,444	5
-1,944,867		1,382,782			91,398	6
-6,144						7
-1,279						8
50,041		195,179			63,725	9
		502,811				10
		127,059				11
		8,551			1,497	12
114,209	111,303	82,657			972,737	13
		-805,871			-385,982	14
						15
	562,130					16
		179				17
		942,570			7,226	18
7,204,985		27,404,433			-27,301,902	19
30,430,029					30,430,029	20
11,134		35,724			-102,109	21
49,891					49,891	22
						23
		-18,879				24
37,710		223,639				25
35,945,709	673,433	29,559,524			3,956,954	26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
		55				39
-413,012					-413,012	40
39,814,135	986,256	-1,117,711			15,504,331	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 2011/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	WEST VA INC TAX-2010	-3,769,483		2,425,156	-1,344,327	
2	WEST VA INC TAX-2011			-338,590	384,000	
3	WVA FRANCHISE - 2010			-110,989	-110,989	
4	WVA FRANCHISE - 2011			200,615	254,100	
5	REAL & PERS PROP-2009	57,084			57,084	
6	REAL & PERS PROP-2010	106,406		-48,895	28,755	
7	REAL & PERS PROP-2011			26,175		
8	WV USE TAX - 2010	3,165			3,165	
9	WV USE TAX - 2011			29,956	27,141	
10	WV EXCISE TAX - 2010	72,883		1,300	74,183	
11	WV EXCISE TAX - 2011			323,633	236,769	
12	UNEMPLOYMENT - 2011	76,282		48,208	65,229	
13	SUBTOTAL West Virginia	-3,453,663		2,143,612	-324,835	
14						
15	STATE OF OHIO:					
16	OHIO FRANCH TAX - 2008					
17	OHIO FRANCH TAX - 2009					
18	OHIO CAT TAX - 2010	170,784		15,600	186,384	
19	OHIO CAT TAX - 2011			687,626	561,626	
20	SUBTOTAL Ohio	170,784		703,226	748,010	
21	STATE OF ILLINOIS:					
22	IL REAL/PERS PROP-2010			2,165	2,165	
23	IL INCOME TAX - 2010	-64,330		-93,869	-158,199	
24	IL INCOME TAX - 2011			-359,031		
25	SUBTOTAL Illinois	-64,330		-450,735	-156,034	
26	STATE OF LOUISIANA:					
27	LA Franchise Tax					
28	LA REAL&PERS PROP-2010				4,504	
29	LA REAL&PERS PROP-2011			427	427	
30	SUBTOTAL Louisiana			427	4,931	
31						
32						
33						
34						
35						
36	RAILCAR PROP TAX:					
37	Misc States - 2008					
38	Misc States - 2009					
39	AL PROP TAX - 2011			118	118	
40	AR PROP TAX -2009			3,657	3,657	
41	TOTAL	8,848,773	1,165,647	14,952,028	-12,549,589	3,643,136

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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)	
		1,991,798			433,358	1
-722,590		-340,106			1,516	2
		-108,205			-2,784	3
-53,485		200,115			500	4
		3,414			-3,414	5
28,756		3,415			-52,310	6
26,175					26,175	7
						8
2,815					29,956	9
					1,300	10
86,864					323,633	11
59,261		-7,841			56,049	12
-985,216		1,742,645			400,967	13
						14
						15
						16
						17
		15,600				18
126,000		687,626				19
126,000		703,226				20
						21
					2,165	22
		-93,741			-128	23
-359,031		-359,843			812	24
-359,031		-453,584			2,849	25
						26
						27
-4,504						28
		427				29
-4,504		427				30
						31
						32
						33
						34
						35
						36
						37
						38
					118	39
					3,657	40
39,814,135	986,256	-1,117,711			15,504,331	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 2011/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	CA PROP TAX - 2011			543	543	
2	CO PROP TAX - 2009			3,236	3,236	
3	GA PROP TAX - 2010			77	77	
4	MO PROP TAX - 2010			36,317	36,317	
5	MO PROP TAX - 2011			30,330		
6	MS PROP TAX - 2010			4,498	4,498	
7	MT PROP TAX - 2010			428	428	
8	NE PROP TAX-2008					
9	NE PROP TAX-2009	80,025		-57,649	22,376	
10	NE PROP TAX-2010	68,884				
11	NE PROP TAX-2011			52,760		
12	NV PROP TAX - 2011			49	49	
13	SC PROP TAX - 2011			223	223	
14	TN PROP TAX - 2010			145	145	
15	UT PROP TAX - 2010			84	84	
16	VA PROP TAX - 2010			878	878	
17	WA PROP TAX - 2008			28	28	
18	WY PROP TAX-2010	23,236		-3,408	19,828	
19	WY PROP TAX-2011			12,930		
20	SUBTOTAL Railcar Prop Tax	172,145		85,244	92,485	
21	STATE OF MISSOURI					
22	UNEMPLOYMENT - 2011	-73,580		16,620		
23	MO LICENSE TAX - 2011			40	40	
24	MO FRANCHISE - 2011	-1,258			-1,258	
25	MO FRANCHISE - 2012				1,258	
26	SUBTOTAL Missouri	-74,838		16,660	40	
27						
28	MISC RTD PROP TX-2008	3,517,128		565,408	2,097,932	
29	MISC RTD PROP TX-2009					
30						
31	FED INCOME TAX FIN-48 -	339,216		-339,216		
32	STATE INCOME TAX FIN-48	204,272		-1,265,270	-2,510,233	
33						
34	MICHIGAN LICENSE TAX			100	100	
35	NC LICENSE TAX			25	25	
36						
37	VARIOUS FRANCHISE TAX			565	565	
38						
39	FIT IRS AUDIT			4,191,841		
40	SIT LONG TERM			528,571		
41	TOTAL	8,848,773	1,165,647	14,952,028	-12,549,589	3,643,136

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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)	
					543	1
					3,236	2
					77	3
					36,317	4
30,330					30,330	5
					4,498	6
					428	7
						8
					-57,649	9
68,884						10
52,760					52,760	11
					49	12
					223	13
					145	14
					84	15
					878	16
					28	17
					-3,408	18
12,930					12,930	19
164,904					85,244	20
						21
-56,960					16,620	22
		40				23
						24
-1,258						25
-58,218		40			16,620	26
						27
1,984,604						28
						29
						30
						31
1,449,235		-730,542			-6,157	32
						33
		100				34
		25				35
						36
		565				37
						38
4,191,841						39
528,571						40
39,814,135	986,256	-1,117,711			15,504,331	41

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

$3,862,881 - Tax Credit Carryforward

($3,742) - Fuel Tax Credit

($216,000) - NOL Carryforward

$3,643,139 Total

Schedule Page: 262.1 Line No.: 15 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.: 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.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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%	191,838			4114	5,907	
4	7%						
5	10%	55,224,460			4114	2,777,485	
6							
7							
8	TOTAL	55,416,298				2,783,392	
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							
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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 2011/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
185,931			3
			4
52,446,975			5
			6
			7
52,632,906			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
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			40
			41
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			45
			46
			47
			48

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, 2011

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	29,467,839
2	Accrued Vacation, Holiday, and Other Non-Productive	20,439,930
3	Accrued Payroll	4,081,116
4	Payroll Deductions	911,783
5	Miscellaneous Employee Benefits (2 Items)	1,891,081
6	Accrued Workers Compensation	642,133
7	Accrued Lease/Rents	53,340,226
8	Accrued Revenue Refunds	4,376,957
9	Control Cash Disbursements	7,406,336
10	Accrued Civil Penalties	5,329,118
11	Spent Nuclear Fuel Disposal Costs	3,689,824
12	Miscellaneous Current & Accrued Liabilities (8 Items)	1,247,580
13	Environmental Accruals	7,811,321
14	Severance Accruals	56,447
15		
16		
17		
18		
19		
20	TOTAL	140,691,691

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 2011/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	44,231,513	507	3,706,716		40,524,797
3						
4	Pole Attachment Rentals	594,397	454	1,803,443	1,797,092	588,046
5						
6	IPP-System Upgrade Credits	2,634,178			86,660	2,720,838
7						
8	Defd Gain-Fiber Optics Agrmt					
9	In Kind Service-Amrtz thru 2025	5,103,191	411.6	131,937		4,971,254
10						
11	Deferred Revenues-Verizon					
12	Amortized thru March 2023	581,129	451	47,439		533,690
13						
14	Deferred Revenues-KDL					
15	Amortized thru Dec 2022	107,706	451	9,348		98,358
16						
17	Customer Advance Receipts	4,833,087	142	47,024,907	47,324,768	5,132,948
18						
19	State Mitigation Deferral (NSR)	886,272	242	886,272		
20						
21	Federal Mitigation Deferral (NSR)	3,876,332	506,242	3,876,332		
22						
23	SEMCO Agreement - MGP Sites				2,500,000	2,500,000
24						
25	Cook U1 Fire insurance	16,000,000	143	16,000,000		
26						
27	Contract Settlement reserves	2,583,476	447	36,160		2,547,316
28						
29	Environmental Site Remediation	10,200,000	242	7,503,654		2,696,346
30						
31	Minor Items	618,577	various	2,991,524	2,528,614	155,667
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	92,249,858		84,017,732	54,237,134	62,469,260

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	283,301		20,533
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	283,301		20,533
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)	283,301		20,533
18	Classification of TOTAL			
19	Federal Income Tax	283,301		20,533
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 2011/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
						262,768	4
							5
							6
							7
						262,768	8
							9
							10
							11
							12
							13
							14
							15
							16
						262,768	17
							18
						262,768	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 2011/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	717,325,019	129,614,468	39,030,943
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	717,325,019	129,614,468	39,030,943
6	Non-Utility	295,451	29,713	1,290
7	SFAS 109/FIN 48	59,608,272		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	777,228,742	129,644,181	39,032,233
10	Classification of TOTAL			
11	Federal Income Tax	777,228,742	129,644,181	39,032,233
12	State Income Tax			
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

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
						807,908,544	2
							3
							4
						807,908,544	5
						323,874	6
		various	33,799,988	various	33,320,999	59,129,283	7
							8
			33,799,988		33,320,999	867,361,701	9
							10
			33,799,988		33,320,999	867,361,701	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 2011/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	93,827,956	12,670,731	4,511,474
4	Reg Asset - SFAS 143 - ARO	424,290,331	49,141,158	22,362,237
5	Deferred Cook O&M Restart Cost	18,828,232	11,753,252	16,388,734
6	Nuclear Fuel	3,247,794	81,247,378	49,100,043
7	Mark To Market	16,326,669	10,765,395	12,149,254
8	Other	42,073,759	25,224,838	28,318,018
9	TOTAL Electric (Total of lines 3 thru 8)	598,594,741	190,802,752	132,829,760
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	151,627,155		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	750,221,896	190,802,752	132,829,760
20	Classification of TOTAL			
21	Federal Income Tax	670,573,921	190,802,752	132,829,760
22	State Income Tax	79,647,975		
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
						101,987,213	3
						451,069,252	4
						14,192,750	5
						35,395,129	6
						14,942,810	7
						38,980,579	8
						656,567,733	9
							10
							11
							12
							13
							14
							15
							16
							17
3,256,532	3,055,180	various	41,986,056	various	78,635,120	188,477,571	18
3,256,532	3,055,180		41,986,056		78,635,120	845,045,304	19
							20
3,256,532	3,055,180		31,447,842		40,570,323	737,870,746	21
			10,538,214		38,064,797	107,174,558	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	3,005,886	3,207,238
SFAS 133	722,126	622,604
SFAS 109	147,899,143	184,647,729
Total Line 18	151,627,155	188,477,571

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	28,045,115	456	99,456,527	93,196,274	21,784,862
2						
3	Asset Retirement Oblig-Excess Provision SFAS 143	353,688,636	228	106,997,016	130,469,905	377,161,525
4						
5	SNF Trust Funds - Pre 4/83	41,932,310	various	6,975,285	7,645,539	42,602,564
6						
7	Over-Recovered Fuel Costs		various	2,888,404	2,888,404	
8						
9	Gains on Foreign Currency Derivatives	147,016	403	11,309		135,707
10	Amortz 1/2009 - 12/2023					
11						
12	PJM Over-Recovered Expenses	11,670,747	447	28,189,485	16,518,738	
13						
14	Clean Coal Technology Rider	2,494,466	various	4,007,308	2,754,838	1,241,996
15	Over-Recovered Expenses					
16						
17	DSM Environmental Optimization	1,287,394	402,442,908	1,623,518	11,413,632	11,077,508
18	Over-Recovered Carrying Charges					
19						
20	SFAS 109 Deferred FIT	36,218,224	various	2,960,982	13,477	33,270,719
21						
22	Fuel Adj. Clause 66 Customer Credits - IN		253	13,500,000	13,500,000	
23						
24	Over Recovered Environmental		182,509	2,045,921	2,246,573	200,652
25	Compliance Tracker					
26						
27	OSS Margin Sharing		447	308,617	6,200,390	5,891,773
28						
29	Residual Refund - MI Interim Rate		various	79,902	397,804	317,902
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	475,483,908		269,044,274	287,245,574	493,685,208

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Company	(2) [ ] A Resubmission		December 31, 2011

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)
278	5	e	MPSC adopted the FERC Uniform System of Accounts for electric utilities in Case No. U-14811. In previous years, the MPSC permitted I&M to record decommissioning expense in conformance with FERC Uniform System of Accounts for general ledger purposes, but required I&M to reclass the Michigan portion of this expense from account 524 to account 403 for Michigan reporting purposes. I&M has restated the amount for the previous year to reflect the adoption of FERC Uniform System of accounts.

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, 2011

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	Two (2) properties each with original				
5	cost less than $100,000	6,838.00		189,155.00	
6					
7	Bluff Point Wind Project to				
8	NextEra	910,901.00		589,099.00	
9					
10	Sale of Non-Utility Property				
11					
12					
13					
14	Three (3) Barges to				
15	Azcon Corp	142,662.00		210,000.00	
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27	Total Gain	1,060,401.00		988,254.00	

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, 2011

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

Line No.	Description of Property (a)	Original Cost of Related Property (b)	Date Journal Entry Approved (When Required) (c)	Account 421.1 (d)	Account 421.2 (e)
28	Loss on disposition of property:				
29					
30	Sale of Utility Property				
31					
32					
33					
34	I&M Boat #3-- to PNC Equipment Services	16,347,981.00			(49,696.00)
35					
36	I&M Boat #4-- to Suntrust Equipment Finance & Leasing Corp	16,887,141.00			(32,842.00)
37					
38					
39					
40					
41					
42					
43	Total Loss	33,235,122.00			(82,538.00)

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, 2011

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	121,007,840
10	-Expenses - Operation	(109,635,521)
11	-Maintenance	(3,361,091)
12	-Depreciation, Depletion, and Amortization	(713,083)
13	-Other	0
14	Total Account 417	7,298,145
15		
16	Account 418 - Nonoperating Rental Income	
17	-Rent Revenue	136,650
18	-Expense	80,845
19	-Other	0
20	Total Account 418	217,495
21		
22	Account 418.1 - Equity in Earnings of Subsidiary Companies	(41,619)
23		
24	Account 419 - Interest and Dividend Income	
25	- Communications Leases	698,822
26	- Margin Interest	2,714
27	- Dedicated Sales	55,759
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, 2011

PARTICULARS CONCERNING CERTAIN OTHER INCOME ACCOUNTS

Line No.	Item (a)	Amount (b)
1		
2	- Other	3,304
3	- Associated Companies	192,005
4	- Tax Items	1,994,450
5	Total Account 419	2,947,054
6		
7		
8	Account 419.1 - Allowance for Funds Used During Contruction	15,395,278
9		
10	Account 421 - Miscellaneous Nonoperating Income	
11	- Allowances	2,722
12	- Power Trading	273,801
13	- Royalties	4,296
14	- Deregulation Implementation Carrying Charge	430,008
15	MPSC Case U-12652	
16	- RTO Carrying Charges	445,869
17	- Other	135,235
18	- Rents	14,285
19	- Clean Coal Technology Carrying Charge	(1,819,470)
20	- Private Fuel Storage	(2,763)
	- Michigan Lost Net Revenue	1,762
21	- Michigan Energy Optimization	(152)
22	Total Account 421	(514,407)
23		
24	Account 421.1 - Gain on Disposition of Property	988,254
25		
26	Account 421.2 - Loss on Disposition of Property	(82,538)
27		
28		
29		
30		
31		
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34		
35		
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37		
38		
39		
40		
41		
42		
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47		
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49		
50		
51	Total Other Income	26,207,662

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 31,2011

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	106,714,162	96,805,235
3	(442) Commercial and Industrial Sales		
4	Small (or Commercial)	69,016,072	64,072,356
5	Large (or Industrial)	56,230,156	53,850,659
6	(444) Public Street and Highway Lighting	1,604,622	1,552,775
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	233,565,012	216,281,025
13			
14	(447) Sales for Resale	37,280,639	45,158,714
15	TOTAL Sales of Electricity	270,845,651	261,439,739
16			
17	(Less) (449.1) Provision for Rate Refunds	461,786	
18	TOTAL Revenue Net of Provision for Refunds	**270,383,865**	**261,439,739**
19	Other Operating Revenues		
20	(450) Forfeited Discounts	676,684	627,168
21	(451) Miscellaneous Service Revenues	210,011	91,862
22	(453) Sales of Water and Water Power		
23	(454) Rent from Electric Property	1,200,449	1,233,688
24	(455) Interdepartmental Rents		
25	(456) Other Electric Revenues	(1,237,529)	(9,134,778)
26			
27			
28			
29			
30	TOTAL Other Operating Revenues	849,615	(7,182,060)
31			
32	TOTAL Electric Operating Revenues	**271,233,480**	**254,257,679**

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 31,2011

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)	
1,247,602	1,277,157	109,164	109,362	1 2
				3
804,630	815,621	17,369	17,243	4
795,562	851,527	986	985	5
11,269	11,507	328	341	6 7 8 9 10 11
2,859,063	2,955,812	127,847	127,931	12 13
611,721	614,204	5	5	14
3,470,784 **	3,570,016	127,852	127,936	15 16 17
3,470,784	3,570,016	127,852	127,936	18

* Include ($809,313) unbilled revenues.

** Includes (15,764) 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 31,2011

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)
300	25	b	The amount reported on line 25 for the year 2011 includes ($7.0M) adjustment of insurance proceeds.
300	25	c	The amount reported on line 25 for the year 2010 includes ($9.8M) adjustment of insurance proceeds.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Company	(1) [ ] An Original (2) [ ] A Resubmission		December 31, 2011

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	None	None
2	Residential Sales		
3	Commercial and Industrial Sales		
4	Small (or Commercial)		
5	Large (or Industrial)		
6			
7			
8			
9			
10			
11			
12	TOTAL Customer Choice Sales		
13			
14			
15	TOTAL Sales of Electricity		
16			
17			
18	TOTAL Revenue Net of Provision for Refunds		
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		

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, 2011

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)	
None	None	None	None	1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				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 31,2011

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	1,138,323	96,474,995	102,184	11,140	0.0848
3	RESIDENTIAL SERVICE TOD	87,317	7,020,715	4,770	18,305	0.0804
4	SMALL GENERAL SERVICE	0	0	0	0	0.0000
5	RESIDENTIAL OFF PEAK ENERGY	15,399	1,036,263	587	26,233	0.0673
6	RESIDENTIAL SVC OPT SENIOR	9,630	677,382	1,623	5,933	0.0703
7	OUTDOOR LIGHTING	4,038	811,590			0.2010
8	UNBILLED	(7,105)	(421,261)			0.0593
9	UNRECOVERED FUEL		1,114,478			
10	Total Residential Sales	1,247,602	106,714,162	109,164	11,429	0.0855
11						
12	442 Commercial Sales					
13	SMALL GENERAL SERVICE	83,963	9,163,631	12,758	6,581	0.1091
14	MEDIUM GENERAL SERVICE	322,672	29,343,113	3,366	95,862	0.0909
15	MEDIUM GENERAL SERVICE TOD	5,496	451,361	98	56,082	0.0821
16	LARGE GENERAL SERVICE	213,419	15,914,998	228	936,048	0.0746
17	LARGE POWER	98,453	6,081,354	4	24,613,250	0.0618
18	QUANTITY POWER	132	9,480	0	0	0.0718
19	ELECTRIC HEATING GENERAL	4,226	336,548	62	68,161	0.0796
20	ELECTRIC HEATING SCHOOLS	9,851	697,144	19	518,474	0.0708
21	MUNICIPAL & SCHOOL SERVICE	26,513	2,307,074	196	135,270	0.0870
22	IRRIGATION SERVICE	6,712	659,441	383	17,525	0.0982
23	WATER & SEWAGE SERVICE	26,591	1,904,495	254	104,689	0.0716
24	STREETLIGHTING SERVICE	12	1,509	1	12,000	0.1258
25	RESIDENTIAL SERVICE	67	3,466	0	0	0.0517
26	OUTDOOR LIGHTING	6,211	1,002,467			0.1614
27	UNBILLED	312	78,701			0.2522
28	UNRECOVERED FUEL		1,061,290			
29	Total Commercial Sales	804,630	69,016,072	17,369	46,326	0.0858
30						
31	442 Industrial Sales					
32	SMALL GENERAL SERVICE	2,817	306,691	390	7,223	0.1089
33	MEDIUM GENERAL SERVICE	122,355	10,952,390	492	248,689	0.0895
34	MEDIUM GENERAL SERVICE TOD	71	5,896	1	71,000	0.0830
35	LARGE GENERAL SERVICE	172,453	13,109,356	73	2,362,370	0.0760
36	LARGE POWER	488,473	30,384,836	25	19,538,920	0.0622
37	QUANTITY POWER	17,035	938,978	1	17,035,000	0.0551
38	ELECTRIC HEATING GENERAL	443	35,659	4	110,750	0.0805
39	OUTDOOR LIGHTING	880	129,384			0.1470
40	ESTIMATED	0	0			0.0000
41	UNBILLED	(8,965)	(466,327)			0.0520
42	UNRECOVERED FUEL		833,293			
43	Total Industrial Sales	795,562	56,230,156	986	806,858	0.0707

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 31,2011

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	597	75,100	163	3,663	0.1258
3	MEDIUM GENERAL SERVICE	106	9,721	2	53,000	0.0917
4	SL CUST OWNED SYS	523	60,801	6	87,167	0.1163
5	SL CUST OWNED SYS METERED	541	38,464	26	20,808	0.0711
6	MUNICIPAL & SCHOOL	159	15,962	7	22,714	0.1004
7	ENERGY CONSERV LIGHTING	5,009	773,604	79	63,405	0.1544
8	STREETLIGHTING SERVICE	4,236	608,015	45	94,133	0.1435
9	OUTDOOR LIGHTING	105	17,547			0.1671
10	UNBILLED	(7)	(425)			0.0607
11	UNRECOVERED FUEL		5,833			
12	Total Public Street & Highway Light	11,269	1,604,622	328	34,357	0.1424
13						
14	Fuel Clause (see footnote)					
15						
16						
17						
18						
19						
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54						
55	Total Billed	2,874,827	234,374,325	127,847	22,486	0.0815
56	Total Unbilled Rev. (See Instr. 6)	(15,764)	(809,313)			0.0513
57	TOTAL	**2,859,063**	**233,565,012**	**127,847**	22,363	0.0817

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 31,2011

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)	
304.1	14	a	440 Residential Sales	
			RESIDENTIAL SERVICE	(352,471)
			RESIDENTIAL SERVICE TOD	(26,938)
			OUTDOOR LIGHTING	(1,318)
			RESIDENTIAL OFF PEAK ENERGY STORAGE	(4,741)
			RESIDENTIAL SVC OPT SENIOR CITIZEN	(2,995)
			RESIDENTIAL TOTAL	(388,463)
			442 Commercial Sales	
			RESIDENTIAL SERVICE	440
			SMALL GENERAL SERVICE	(27,439)
			MEDIUM GENERAL SERVICE	(99,949)
			MEDIUM GENERAL SERVICE TOD	(1,751)
			LARGE GENERAL SERVICE	(65,466)
			LARGE POWER	(29,881)
			QUANTITY POWER	1,807
			ELECTRIC HEATING GENERAL	(1,309)
			ELECTRIC HEATING SCHOOLS	(3,041)
			MUNICIPAL & SCHOOL SERVICE	(8,346)
			IRRIGATION SERVICE	(1,625)
			WATER & SEWAGE SERVICE	(8,005)
			OUTDOOR AND STREET LIGHTING	(2,026)
			COMMERCIAL TOTAL	(246,591)
			442 Industrial Sales	
			SMALL GENERAL SERVICE	(871)
			MEDIUM GENERAL SERVICE	(38,414)
			MEDIUM GENERAL SERVICE TOD	(20)
			LARGE GENERAL SERVICE	(53,717)
			LARGE POWER	(151,641)
			QUANTITY POWER	(2,421)
			ELECTRIC HEATING GENERAL	(141)
			OUTDOOR AND STREET LIGHTING	(289)
			INDUSTRIAL TOTAL	(247,514)
			444 Public Street & Highway Light	
			SMALL GENERAL SERVICE	(186)
			MEDIUM GENERAL SERVICE	(37)
			SL CUST OWNED SYS METERED	(315)
			MUNICIPAL & SCHOOL SERVICE	(50)
			OUTDOOR AND STREET LIGHTING	(1,164)
			ENERGY CONSERVE LIGHTING	(1,340)
			PUBLIC STREET & HIGHWAY LIGHT TOTAL	(3,092)
			GRAND TOTAL	**(885,660)**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Company	(1) [ ] An Original (2) [ ] A Resubmission		December 31, 2011

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	None					
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 Billed					
45	Total Unbilled Rev. (See Instr. 6)					
46	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	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	Town of Avila	RQ	IMPCO#105			
11	Town of New Carlisle	RQ	IMPCO#103			
12	Town of Warren	RQ	IMPCO#110			
13	Village of Paw Paw	RQ	IMPCO#111			
14	Wabash Valley Power Assoc Inc.	RQ	IMPCO#112			
	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)		
433,933	4,013,886	20,785,963		24,799,849	1
312,964	12,394,318	6,127,906		18,522,224	2
67,929	3,061,655	1,363,877		4,425,532	3
90,980	3,933,441	1,834,682		5,768,123	4
621,122	26,561,804	12,993,935		39,555,739	5
134,447	5,874,845	2,913,776		8,788,621	6
142,360	5,679,907	3,076,429		8,756,336	7
222,963	9,466,451	4,615,446		14,081,897	8
1,561,858	51,651,418	28,537,624		80,189,042	9
34,184	1,449,357	695,810		2,145,167	10
12,180	548,285	301,629		849,914	11
19,148	837,680	415,719		1,253,399	12
44,021	1,976,196	1,044,442		3,020,638	13
1,204,084	51,216,818	24,574,288		75,791,106	14
4,902,173	178,666,061	109,281,526	-25,643,676	262,303,911	
17,056,685	61,018,002	466,189,089	0	527,207,091	
21,958,858	**239,684,063**	**575,470,615**	**-25,643,676**	**789,511,002**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	PJM Transmission for RQ Customers	RQ	Various			
2	AEP Service Corporation	OS	17			
3	AEP Service Corporation	OS	20			
4	AEP System Pool	OS				
5	Advan Promotions Inc.	OS	Note1			
6	Allegheny Electric Cooperative	OS	Note1			
7	AMER APN Starfist LP	OS	Note1			
8	Ameren Energy Marketing	OS	Note1			
9	American Municipal Power-Ohio	OS	Note1			
10	American PowerNet Management	OS	Note1			
11	Associated Elect Cooperative	OS	Note1			
12	B.P. Energy Company	OS	Note1			
13	Baltimore Gas & Electric	OS	Note1			
14	Barclays Bank PLC	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)		
			-25,643,676	-25,643,676	1
26,622		908,503		908,503	2
		-12,932		-12,932	3
11,909,815	46,740,204	261,689,553		308,429,757	4
		-9,476		-9,476	5
99,397		6,878,767		6,878,767	6
	2,128			2,128	7
4,177		144,092		144,092	8
76,254	953,022	3,705,076		4,658,098	9
221		16,828		16,828	10
-9,290		-291,283		-291,283	11
-7,819		-260,358		-260,358	12
90,546		6,883,796		6,883,796	13
36,359		1,630,625		1,630,625	14
4,902,173	178,666,061	109,281,526	-25,643,676	262,303,911	
17,056,685	61,018,002	466,189,089	0	527,207,091	
21,958,858	**239,684,063**	**575,470,615**	**-25,643,676**	**789,511,002**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
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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.
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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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Beech Ridge Energy LLC	OS	Note1			
2	Big Rivers Electric Corp	OS	Note1			
3	BP AMOCO	OS	Note1			
4	Buckeye Rural Electric Admin	OS	Note1			
5	California ISO	OS	Note1			
6	California Power Exchange	OS	Note1			
7	Calpine Power Service Company	OS	Note1			
8	Carolina Power & Light	OS	IMPCO#77			
9	Cincinnati Gas and Electric	OS	Note1			
10	Citigroup Energy Inc.	OS	Note1			
11	Citizens Elect Co & Wellsborough	OS	Note1			
12	City of Batavia	OS	Note1			
13	City of Columbus	OS	Note1			
14	City of Croswell, MI	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)		
		-79,910		-79,910	1
-10,796		-629,665		-629,665	2
		139,068		139,068	3
49,622		31,054,399		31,054,399	4
		2		2	5
		-905		-905	6
-6,520		-284,761		-284,761	7
54		1,004		1,004	8
		-7,606		-7,606	9
6,468		384,621		384,621	10
3,067		168,436		168,436	11
5,088		335,461		335,461	12
169,073		11,157,277		11,157,277	13
7,741		382,872		382,872	14
4,902,173	178,666,061	109,281,526	-25,643,676	262,303,911	
17,056,685	61,018,002	466,189,089	0	527,207,091	
21,958,858	**239,684,063**	**575,470,615**	**-25,643,676**	**789,511,002**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
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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 Dowagiac, MI	OS	Note 1			
2	City of Lebanon	OS	Note1			
3	City of Shelby	OS	Note1			
4	City of Westerville	OS	Note1			
5	City of Kirkwood, Missouri	OS	Note1			
6	Cleveland Public Power	OS	Note1			
7	Cleveland Toledo OH PA Electric	OS	Note1			
8	CMS Marketing Svcs and Trading	OS	Note1			
9	Commonwealth Edison Company	OS	Note1			
10	Conoco Inc.	OS	Note1			
11	Constellation Energy Commodities	OS	Note1			
12	Cook Inlet Energy Supply LP	OS	Note1			
13	Credit Suisse Energy	OS	Note1			
14	DB Energy Trading LLC	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		5	1
21,950		1,674,084		1,674,084	2
10,544		588,462		588,462	3
54,161		4,494,509		4,494,509	4
6,552	293	195,885		196,178	5
36,266		1,848,775		1,848,775	6
	292,779	46,025		338,804	7
-770		-35,857		-35,857	8
200,076		7,537,655		7,537,655	9
9		1,508		1,508	10
70,931		3,028,016		3,028,016	11
-5,470		-71,682		-71,682	12
		-5,636		-5,636	13
-1,367		20,704		20,704	14
4,902,173	178,666,061	109,281,526	-25,643,676	262,303,911	
17,056,685	61,018,002	466,189,089	0	527,207,091	
21,958,858	**239,684,063**	**575,470,615**	**-25,643,676**	**789,511,002**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	Delaware Electric Municipal Co	OS	Note1			
2	Delmarva Power & Light	OS	Note1			
3	Dominion Equipment Inc.	OS	Note1			
4	DP&L Power Services	OS	Note1			
5	DTE Energy Trading Inc.	OS	Note1			
6	Duke Energy Carolinas, LLC	OS	Note1			
7	Duke Energy Indiana, Inc.	OS	Note1			
8	Duke Energy Kentucky, Inc.	OS	Note1			
9	Duke Energy Ohio, Inc.	OS	Note1			
10	Duke Energy Trading	OS	Note1			
11	Duquesne Light Company	OS	Note1			
12	Duquesne Power, L.P.	OS	Note1			
13	Dynegy Power Marketing Inc.	OS	Note1			
14	East KY Power Co-Op Power Mktg	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)		
91,399		5,750,432		5,750,432	1
37,526		3,007,337		3,007,337	2
2,160		92,097		92,097	3
1,536		245,380		245,380	4
65,351		2,449,910		2,449,910	5
1,436		28,909		28,909	6
		-1,388		-1,388	7
		103		103	8
		-25,331		-25,331	9
-1		-115		-115	10
46,645		1,579,305		1,579,305	11
56,983		2,457,051		2,457,051	12
		9,178		9,178	13
274		10,075		10,075	14
4,902,173	178,666,061	109,281,526	-25,643,676	262,303,911	
17,056,685	61,018,002	466,189,089	0	527,207,091	
21,958,858	**239,684,063**	**575,470,615**	**-25,643,676**	**789,511,002**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	EDF Trading North America LLC	OS	Note1			
2	Edison Mission Mktg & Trading	OS	Note1			
3	Endure Energy, LLC	OS	Note1			
4	Energy America, LLC	OS	Note1			
5	Eng Mktg, div of Amerada Hess	OS	Note1			
6	Entergy Power Serv	OS	Note1			
7	Exelon Generation - Power Team	OS	Note1			
8	FirstEnergy Trading Services	OS	Note1			
9	GBC Metals, LLC	OS	Note1			
10	Harrison Rural Electrification	OS	Note1			
11	Hess Energy Trading Company	OS	Note1			
12	Hoosier Power Market	OS	Note1			
13	Illinois Municipal Elec Agency	OS	Note1			
14	Indiana Municipal Power Agency	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)		
19,670		814,202		814,202	1
95,947		3,479,595		3,479,595	2
154		5,656		5,656	3
654		93,334		93,334	4
		499,658		499,658	5
5,769		247,438		247,438	6
-84,833		-6,440,158		-6,440,158	7
450,259		27,354,168		27,354,168	8
		-2,764		-2,764	9
19,668		1,524,807		1,524,807	10
		12,916		12,916	11
-54,933		-1,936,112		-1,936,112	12
2,686	9,089	196,284		205,373	13
18,582		869,388		869,388	14
4,902,173	178,666,061	109,281,526	-25,643,676	262,303,911	
17,056,685	61,018,002	466,189,089	0	527,207,091	
21,958,858	**239,684,063**	**575,470,615**	**-25,643,676**	**789,511,002**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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 Power & Light Co	OS	Note1			
4	J Aron & Company	OS	Note1			
5	JP Morgan Ventures Energy Corp	OS	Note1			
6	Kansas City Power & Light Co	OS	Note1			
7	Kentucky Municipal Power Agency	OS	Note1			
8	Letterkenny Industrial Dev Auth	OS	Note1			
9	LG&E Utilities Power Sales	OS	Note1			
10	Merrill Lynch Commodities, Inc.	OS	Note1			
11	Michigan Public Power Agency	OS	Note1			
12	MidAmerican Energy	OS	Note1			
13	Midwest ISO	OS	Note1			
14	Mizuho Securities USA 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)		
	3,513			3,513	1
4,624		554,484		554,484	2
-6,776		-281,079		-281,079	3
553,015		19,296,742		19,296,742	4
144,679		3,058,357		3,058,357	5
1,316		50,532		50,532	6
75,276		4,372,676		4,372,676	7
15,078		1,094,211		1,094,211	8
696		29,921		29,921	9
		-871,244		-871,244	10
11,926		624,770		624,770	11
81,784		4,147,413		4,147,413	12
-614,682		-22,770,677		-22,770,677	13
		-793,031		-793,031	14
4,902,173	178,666,061	109,281,526	-25,643,676	262,303,911	
17,056,685	61,018,002	466,189,089	0	527,207,091	
21,958,858	**239,684,063**	**575,470,615**	**-25,643,676**	**789,511,002**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
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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	Morgan Stanley Capt.	OS	Note1			
2	NC Electric Membership Corp.	OS	Note1			
3	NextEra Energy Power Mktg LLC	OS	Note1			
4	North Carolina Muni Power Agency	OS	Note1			
5	Noble Americas Gas and Power Corp	OS	Note1			
6	NRG Power Marketing Inc.	OS	Note1			
7	NSP Energy Marketing	OS	Note1			
8	Old Dominion Electric	OS	Note1			
9	OSS Over/Under	OS	Note1			
10	Otter Tail Power Company	OS	Note1			
11	Paribas	OS	Note1			
12	PECO Energy	OS	Note1			
13	Pennsylvania Power Company	OS	Note1			
14	PEPCO Services Inc.	OS	Note1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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

MegaWatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
7,204		753,995		753,995	1
386,245		14,598,104		14,598,104	2
130,245		6,757,072		6,757,072	3
10		458		458	4
		1,578		1,578	5
6,795		299,298		299,298	6
		-254		-254	7
49,748		2,665,621		2,665,621	8
		-18,983,184		-18,983,184	9
		9,798		9,798	10
		9,779		9,779	11
62,894		4,701,474		4,701,474	12
16,728		907,024		907,024	13
109,331		5,186,345		5,186,345	14
4,902,173	178,666,061	109,281,526	-25,643,676	262,303,911	
17,056,685	61,018,002	466,189,089	0	527,207,091	
21,958,858	**239,684,063**	**575,470,615**	**-25,643,676**	**789,511,002**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	PJM Environmental Info System Inc.	OS	Note1			
2	PJM Interconnection	OS	Note1			
3	Potomac Electric Power Company	OS	Note1			
4	PP&L Energy Plus Co.	OS	Note1			
5	PPL Electric Utilities Corp	OS	Note1			
6	Prairie Power, Inc.	OS	Note1			
7	Prairieland Energy Incorporate	OS	Note1			
8	PSEG Energy Resources & Trade	OS	Note1			
9	Quasar Energy Power Marketing	OS	Note1			
10	Rainbow Energy Marketing	OS	Note1			
11	Sempra Energy Solutions, LLC	OS	Note1			
12	Sempra Energy Trading	OS	Note1			
13	Shell Energy N America (US) LP	OS	Note1			
14	South Nevada Water Authority	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)		
		-1,315		-1,315	1
2,011,641	12,503,545	36,001,919		48,505,464	2
67,448		6,055,314		6,055,314	3
-4,418		-414,970		-414,970	4
15,865		1,148,367		1,148,367	5
35,785		2,536,792		2,536,792	6
42,243	-34	1,328,563		1,328,529	7
-437,323		-20,837,189		-20,837,189	8
-762		-27,884		-27,884	9
		518		518	10
1,295		1,536,692		1,536,692	11
		17,873		17,873	12
37,149		1,671,329		1,671,329	13
		-50		-50	14
4,902,173	178,666,061	109,281,526	-25,643,676	262,303,911	
17,056,685	61,018,002	466,189,089	0	527,207,091	
21,958,858	**239,684,063**	**575,470,615**	**-25,643,676**	**789,511,002**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	South Carolina Electric & Gas	OS	Note1			
2	Southen Maryland Elec Coop Inc	OS	Note1			
3	Southern Company	OS	Note1			
4	Southern Illinois Power Co-Op	OS	Note1			
5	Tenaska Power Services Company	OS	Note1			
6	The Borough of Pitcairn, PA	OS	Note1			
7	The Energy Authority	OS	Note1			
8	The Potomac Edison Company	OS	Note1			
9	Timber Canyon	OS	Note1			
10	Town of Berlin, Maryland	OS	Note1			
11	Town of Hagerstown, Indiana	OS	Note1			
12	TVA Bulk Power Trading	OS	Note1			
13	UBS Securities LLC	OS	Note1			
14	Union Electric Company	OS	Note1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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

MegaWatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
-1		-35		-35	1
126,259		6,069,022		6,069,022	2
4,020		139,808		139,808	3
19,407		771,520		771,520	4
-455		-24,711		-24,711	5
1,740		116,944		116,944	6
5,020		206,759		206,759	7
64,118		3,791,082		3,791,082	8
		-9,475		-9,475	9
4,921		297,170		297,170	10
4,842		295,444		295,444	11
2,499		77,202		77,202	12
		-4,820,253		-4,820,253	13
		-16,985		-16,985	14
4,902,173	178,666,061	109,281,526	-25,643,676	262,303,911	
17,056,685	61,018,002	466,189,089	0	527,207,091	
21,958,858	**239,684,063**	**575,470,615**	**-25,643,676**	**789,511,002**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	Union Power Partners	OS	Note1			
2	Village of Bethel, Ohio	OS	Note1			
3	Village of Glouster	OS	Note1			
4	Village of Hammersville, Ohio	OS	Note1			
5	Village of Ripley, Ohio	OS	Note1			
6	Village of Sebewaing, MI	OS	Note1			
7	Virginia City Hybrid Energy Center	OS	Note1			
8	Wabash Valley Power Assn Inc.	OS	Note1			
9	Washington Gas Energy Services	OS	Note1			
10	West Penn Power Company	OS	Note1			
11	Westar Energy Inc.	OS	Note1			
12	Wisconsin Power & Light	OS	Note1			
13	Wolverine Power Supply Coop	OS	Note1			
14	Adjustments					
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
-4,388		-188,326		-188,326	1
5,484		284,489		284,489	2
85		40,960		40,960	3
1,169		63,859		63,859	4
3,659		189,909		189,909	5
8,467		410,164		410,164	6
		49,438		49,438	7
		29,755		29,755	8
162,762		8,819,451		8,819,451	9
9,541		519,200		519,200	10
-23,470		-840,030		-840,030	11
53,390		3,190,192		3,190,192	12
182,664	513,463	9,006,805		9,520,268	13
		-2,263,703		-2,263,703	14
4,902,173	178,666,061	109,281,526	-25,643,676	262,303,911	
17,056,685	61,018,002	466,189,089	0	527,207,091	
21,958,858	**239,684,063**	**575,470,615**	**-25,643,676**	**789,511,002**	

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: 310.1 Line No.: 2 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: 310.1 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: 310.1 Line No.: 4 Column: a

Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company and Ohio Power Company are associated companies and 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 are governed by the terms of the interconnection agreement dated July 6, 1951, as amended, and are processed by American Electric Power Service Corporation.

Schedule Page: 310.2 Line No.: 13 Column: a

The termination date of this contract is 5/31/2014.

Schedule Page: 310.10 Line No.: 14 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.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2011

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	6,765,439	4,896,705
5	(501) Fuel	298,113,614	308,436,202
6	(502) Steam Expenses	6,830,702	9,186,267
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred - **CR.**		
9	(505) Electric Expenses	1,673,806	1,522,903
10	(506) Miscellaneous Steam Power Expenses	(10,165,847)	18,988,980
11	(507) Rents	70,144,622	70,154,558
12	(509) Allowances	20,635,992	14,432,927
13	TOTAL Operation *(Enter Total of Lines 4 thru 12)*	393,998,328	427,618,542
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	3,832,343	2,456,100
16	(511) Maintenance of Structures	3,009,253	2,592,102
17	(512) Maintenance of Boiler Plant	23,347,481	18,445,532
18	(513) Maintenance of Electric Plant	8,023,365	6,377,617
19	(514) Maintenance of Miscellaneous Steam Plant	2,660,719	2,217,687
20	TOTAL Maintenance *(Enter Total of Lines 15 thru 19)*	40,873,161	32,089,038
21	TOTAL Power Production Expenses-Steam Power *(Total of lines 13 & 20)*	434,871,489	459,707,580
22	**B. Nuclear Power Generation**		
23	Operation		
24	(517) Operation Supervision and Engineering	19,469,804	15,640,025
25	(518) Fuel	159,326,773	157,487,260
26	(519) Coolants and Water	6,135,422	5,564,287
27	(520) Steam Expenses	10,775,472	9,241,483
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred - **CR**		
30	(523) Electric Expenses	2,536,554	2,905,722
31	(524) Miscellaneous Nuclear Power Expenses	76,857,163	78,874,662
32	(525) Rents	0	0
33	TOTAL Operation *(Enter Total of lines 24 thru 32)*	275,101,188	269,713,439
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	11,924,259	13,700,477
36	(529) Maintenance of Structures	3,192,035	2,896,349
37	(530) Maintenance of Reactor Plant Equipment	74,650,363	71,887,442
38	(531) Maintenance of Electric Plant	22,854,776	22,013,144
39	(532) Maintenance of Miscellaneous Nuclear Plant	21,400,375	22,069,952
40	TOTAL Maintenance *(Enter Total of Lines 35 thru 39)*	134,021,808	132,567,364
41	TOTAL Power Production Expenses-Nuclear Power *(Total of lines 33 & 40)*	409,122,996	402,280,803
42	**C. Hydraulic Power Generation**		
43	Operation		
44	(535) Operation Supervision and Engineering	438,870	372,890
45	(536) Water for Power	37,544	
46	(537) Hydraulic Expenses	40,367	74,981
47	(538) Electric Expenses	1,343	3,804
48	(539) Miscellaneous Hydraulic Power Generation Expenses	823,630	635,549
49	(540) Rents	0	0
50	TOTAL Operation *(Enter Total of Lines 44 thru 49)*	1,341,754	1,087,224
51	Maintenance		
52	(541) Maintenance Supervision and Engineering	204,136	169,736
53	(542) Maintenance of Structures	79,201	121,842
54	(543) Maintenance of Reservoirs, Dams, and Waterways	880,625	774,280
55	(544) Maintenance of Electric Plant	675,752	691,881
56	(545) Maintenance of Miscellaneous Hydraulic Plant	86,815	54,102
57	TOTAL Maintenance *(Total of Lines 52 thru 56)*	1,926,529	1,811,841

Name of Respondent	This Report Is:	Date of Report	Year of Report
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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)*	3,268,283	2,899,065
60	**D. Other Power Generation**		
61	Operation		
62	(546) Operation Supervision and Engineering	23,870	47,021
63	(547) Fuel	(5)	
64	(548) Generation Expenses	(13)	29
65	(549) Miscellaneous Other Power Generation Expenses	21,858	106,931
66	(550) Rents		
67	TOTAL Operation *(Total of Lines 62 thru 66)*	45,710	153,981
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant	(20)	0
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	0	0
73	TOTAL Maintenance *(Total of Lines 69 thru 72)*	(20)	0
74	TOTAL Pwr. Production Expenses-Other Power *(Total of Lines 67 & 73)*	45,690	153,981
75	**E. Other Power Supply Expenses**		
76	(555) Purchased Power	510,536,100	531,867,943
77	(556) System Control and Load Dispatching	1,742,725	1,674,189
78	(557) Other Expenses	6,490,781	6,822,816
79	Total Other Power Supply Expenses *(Total of Lines 76 thru 78)*	518,769,606	540,364,948
80	Total Pwr. Production Expenses *(Total of lines 21, 41, 59, 74 & 79)*	1,366,078,064	1,405,406,377
81	**2. TRANSMISSION EXPENSES**		
82	Operation		
83	(560) Operation Supervision and Engineering	1,890,535	1,758,159
84	(561) Load Dispatching		
85	(561.1) Load Dispatch-Reliability	18,751	43,059
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,336,334	1,376,721
87	(561.3) Load Dispatch-Transmission Service and Scheduling	25	49
88	(561.4) Scheduling, System Control and Dispatch Services	5,167,862	3,040,722
89	(561.5) Reliability, Planning and Standards Development	290,402	268,631
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	1,059,859	724,447
93	(562) Station Expenses	741,793	730,884
94	(563) Overhead Lines Expenses	355,042	287,172
95	(564) Underground Lines Expenses	0	0
96	(565) Transmission of Electricity by Others	7,816,222	(19,521,836)
97	(566) Miscellaneous Transmission Expenses	2,220,458	7,065,758
98	(567) Rents	17,871	20,749
99	TOTAL Operation *(Total of Lines 83 thru 98)*	20,915,154	(4,205,485)
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	114,341	118,511
102	(569) Maintenance of Structures	85,538	104,508
103	(569.1) Maintenance of Computer Hardware	178,112	151,696
104	(569.2) Maintenance of Computer Software	744,816	835,340
105	(569.3) Maintenance of Communication Equipment	368,690	410,180
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	3,929,582	3,900,246
108	(571) Maintenance of Overhead Lines	8,123,002	7,314,158
109	(572) Maintenance of Underground Lines	44,894	25,659
110	(573) Maintenance of Miscellaneous Transmission Plant	0	1,510
111	TOTAL Maintenance *(Total of Lines 101 thru 110)*	13,588,975	12,861,808
112	TOTAL Transmission Expenses *(Total of Lines 99 & 111)*	34,504,129	8,656,323
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, 2011

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	5,248,935	3,402,264
122	(575.8) Rents		
123	TOTAL Operation *(Total of Lines 115 thru 122)*	5,248,935	3,402,264
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)*	5,248,935	3,402,264
132	**4. DISTRIBUTION EXPENSES**		
133	Operation		
134	(580) Operation Supervision and Engineering	3,602,470	3,491,154
135	(581) Load Dispatching	1,132,506	1,038,687
136	(582) Station Expenses	996,875	998,639
137	(583) Overhead Line Expenses	1,153,719	1,164,593
138	(584) Underground Line Expenses	1,918,088	1,940,245
139	(585) Street Lighting and Signal System Expenses	100,442	34,499
140	(586) Meter Expenses	947,539	1,382,234
141	(587) Customer Installations Expenses	546,581	521,631
142	(588) Miscellaneous Expenses	2,927,929	22,505,371
143	(589) Rents	1,865,800	1,940,250
144	TOTAL Operation *(Total of Lines 134 thru 143)*	15,191,949	35,017,303
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	155,142	156,383
147	(591) Maintenance of Structures	84,020	72,372
148	(592) Maintenance of Station Equipment	2,908,629	2,815,830
149	(593) Maintenance of Overhead Lines	27,807,703	27,841,811
150	(594) Maintenance of Underground Lines	1,871,679	1,992,741
151	(595) Maintenance of Line Transformers	610,051	717,491
152	(596) Maintenance of Street Lighting and Signal Systems	475,540	437,424
153	(597) Maintenance of Meters	227,822	174,768
154	(598) Maintenance of Miscellaneous Distribution Plant	899,040	2,086,034
155	TOTAL Maintenance *(Total of Lines 146 thru 154)*	35,039,626	36,294,854
156	TOTAL Distribution Expenses *(Total of Lines 144 & 155)*	50,231,575	71,312,157
157	**5. CUSTOMER ACCOUNTS EXPENSES**		
158	Operation		
159	(901) Supervision	1,519,090	1,457,062
160	(902) Meter Reading Expenses	3,010,865	2,937,287
161	(903) Customer Records and Collection Expenses	15,820,807	15,462,876
162	(904) Uncollectible Accounts	157,447	(131,638)
163	(905) Miscellaneous Customer Accounts Expenses	130,082	59,604
164	TOTAL Customer Accounts Expenses *(Total of Lines 159 thru 163)*	20,638,291	19,785,191
165	**6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES**		
166	Operation		
167	(907) Supervision	1,120,374	1,132,175
168	(908) Customer Assistance Expenses	14,686,377	6,172,585
169	(909) Informational and Instructional Expenses	6,407	529,855
170	(910) Miscellaneous Customer Service and Informational Expenses	23	7,899
171	TOTAL Cust. Service and Informational Exp. *(Total of Lines 167 thru 170)*	15,813,181	7,842,514

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Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2011

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	37	278
175	(912) Demonstrating and Selling Expenses	120,365	657
176	(913) Advertising Expenses	1,981	3,400
177	(916) Miscellaneous Sales Expenses		
178	Total Sales Expenses *(Total of Lines 174 thru 177)*	122,383	4,335
179	**8. ADMINISTRATIVE AND GENERAL EXPENSES**		
180	Operation		
181	(920) Administrative and General Salaries	26,005,132	27,715,713
182	(921) Office Supplies and Expenses	3,750,733	3,757,942
183	(Less) (922) Administrative Expenses Transferred - **CR**	4,221,330	3,127,561
184	(923) Outside Services Employed	26,538,028	27,568,369
185	(924) Property Insurance	3,615,009	4,304,774
186	(925) Injuries and Damages	7,188,172	6,439,289
187	(926) Employee Pensions and Benefits	38,464,933	47,294,950
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	12,528,390	12,820,884
190	(929) (Less) Duplicate Charges - **CR**.	748,783	624,937
191	(930.1) General Advertising Expenses	288,023	443,441
192	(930.2) Miscellaneous General Expenses	4,661,707	5,891,674
193	(931) Rents	6,675,670	7,021,243
194	TOTAL Operation *(Total of Lines 181 thru 193)*	124,745,684	139,505,781
195	Maintenance		
196	(935) Maintenance of General Plant	4,433,021	6,780,819
197	TOTAL Administrative and General Expenses *(Total of Lines 194 & 196)*	129,178,705	146,286,600
198	TOTAL Electric Operation and Maintenance Expenses *(Enter total*	1,621,815,263	1,662,695,761
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)	12/31/2011	12/31/2010
2. Total Regular Full-Time Employees	2,649	2,685
3. Total Part-Time and Temporary Employees	6	7
4. Total Employees	2,655	2,692

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Company	(2) [ ] A Resubmission		December 31, 2011

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	c	MPSC adopted the FERC Uniform System of Accounts for electric utilities in Case No. U-14811. In previous years, the MPSC permitted I&M to record decommissioning expense in conformance with FERC Uniform System of Accounts for general ledger purposes, but required I&M to reclass the Michigan portion of this expense from account 524 to account 403 for Michigan reporting purposes. I&M has restated the amount for the previous year to reflect the adoption of FERC Uniform System of accounts.
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.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	AEP GENERATING COMPANY	RQ	AEG 1			
2	AEP SYSTEM POOL	OS				
3	AEP SERVICE CORPORATION	OS				
4	ALLEN FAMILY LIMITED PARTNERSHIP	OS				
5	AMEREN ENERGY MARKETING	OS				
6	ASSOCIATED ELECT COOPERATIVE	OS				
7	BARCLAYS BANK PLC	OS				
8	BEECH RIDGE ENERGY LLC	OS				
9	BP AMOCO	OS				
10	BUCKEYE RURAL ELECTRIC ADMIN	OS				
11	CAROLINA POWER & LIGHT	OS				
12	CITIGROUP ENERGY INC.	OS				
13	CMS MARKETING SERVICES AND	OS				
14	CONSTELLATION ENGY COMMODITIES	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)	
5,730,752			101,936,023	126,803,202		228,739,225	1
3,804,142				124,598,280		124,598,280	2
4,128				146,581		146,581	3
3				80		80	4
29			6,025	1,004		7,029	5
3,868				116,832		116,832	6
7,402				239,119		239,119	7
				13,056		13,056	8
				59,771		59,771	9
				378,381		378,381	10
10				580		580	11
				-929		-929	12
			1,408			1,408	13
41,377			2,288,579	2,067,272		4,355,851	14
13,099,829			135,343,014	375,193,086		510,536,100	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	DP&L POWER SERVICES	OS				
2	DTE ENERGY TRADING INC.	OS				
3	DUKE ENERGY CAROLINAS, LLC	OS				
4	DYNEGY POWER MARKETING INC.	OS				
5	EAST KY POWER CO-OP POWER	OS				
6	EDF TRADING NORTH AMERICA LLC	OS				
7	EDISON MISSION MKTG & TRADING	OS				
8	ENTERGY POWER SERVICES	OS				
9	EXELON GENERATION - POWER TEAM	OS				
10	FIRSTENERGY TRADING SERVICES	OS				
11	FOWLER RIDGE II WIND FARM LLC	OS				
12	FOWLER RIDGE WIND FARM LLC	OS				
13	FRENCH PAPER	OS				
14	FT. WAYNE ELECTRIC JATC	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)	
				-27,486		-27,486	1
4,463				224,582		224,582	2
213				12,763		12,763	3
			8,770			8,770	4
469				17,892		17,892	5
			37,440	7,433		44,873	6
20,614				493,117		493,117	7
2,433				70,059		70,059	8
816				475,116		475,116	9
				68,286		68,286	10
139,419				10,541,500		10,541,500	11
250,723				14,239,830		14,239,830	12
2,977				84,482		84,482	13
1				35		35	14
13,099,829			135,343,014	375,193,086		510,536,100	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	JP MORGAN VENTURES ENERGY CORP	OS				
2	KANSAS CITY POWER & LIGHT CO	OS				
3	LG&E UTILITIES POWER SALES	OS				
4	MADISON GAS AND ELECTRIC CO	OS				
5	MIDWEST ISO	OS				
6	MIZUHO SECURITIES USA INC	OS				
7	NATIONAL POWER COOPERATIVE INC	OS				
8	NC ELECTRIC MEMBERSHIP CORP.	OS				
9	NEXTERA ENERGY POWER MKTG LLC	OS				
10	NOBLE AMERICAS GAS AND POWER	OS				
11	NO CAROLINA MUNI PWR AGENCY	OS				
12	OLD DOMINION ELECTRIC	OS				
13	OVEC POWER SCHEDULING	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)	
3				151		151	1
409				9,915		9,915	2
8,120				306,447		306,447	3
			481			481	4
131,197			142	5,177,800		5,177,942	5
				-56,610		-56,610	6
10,430			107,932	819,640		927,572	7
829				35,789		35,789	8
				25,592		25,592	9
480				18,623		18,623	10
151				6,274		6,274	11
400				12,145		12,145	12
1,363,551			24,164,352	41,440,666		65,605,018	13
1,536,524			6,608,211	46,602,596		53,210,807	14
13,099,829			135,343,014	375,193,086		510,536,100	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	PP&L ENERGY PLUS CO.	OS				
2	PSEG ENERGY RESOURCES & TRADE	OS				
3	RANDOLPH SCHOOLS	OS				
4	SEMPRA ENERGY SOLUTIONS, LLC	OS				
5	SOUTH CAROLINA ELECTRIC & GAS	OS				
6	SOUTHERN MARYLAND ELEC COOP INC	OS				
7	SOUTHERN COMPANY	OS				
8	THE ENERGY AUTHORITY	OS				
9	TITLON ENERGY, LLC	OS				
10	TVA BULK POWER TRADING	OS				
11	UBS SECURITIES LLC	OS				
12	UNION ELECTRIC COMPANY	OS				
13	WABASH VALLEY POWER ASSN INC.	OS				
14	WILLIAM E RICHTER	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)	
2,952				130,511		130,511	1
16,141				893,038		893,038	2
				70,325		70,325	3
				36,593		36,593	4
29				1,762		1,762	5
640				28,993		28,993	6
238				9,788		9,788	7
2,584				116,738		116,738	8
			14,427			14,427	9
10,606				414,929		414,929	10
				698,449		698,449	11
				4,786		4,786	12
			92,335			92,335	13
2				53		53	14
13,099,829			135,343,014	375,193,086		510,536,100	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	WilSCONSIN POWER AND LIGHT	OS				
2	WISCONSIN ELECTRIC POWER CO	OS				
3	WPPI ENERGY	OS				
4	ADJUSTMENTS					
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
704			1,000	20,958		21,958	1
			75,293			75,293	2
			596			596	3
				-2,263,703		-2,263,703	4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
13,099,829			135,343,014	375,193,086		510,536,100	

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 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 are governed by the terms of the interconnection agreement dated July 6, 1951, as amended, and are processed by American Electric Power Service Corporation.

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: 326.4 Line No.: 4 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.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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 Integration	Various	Various	FNO
2	Transmission Service -NonAffil			
3				
4	PJM Network Integration Trans	Various	Various	FNO
5	Revenues-Whlsl Cust-NonAffil			
6				
7	PJM Network Integration Revenue	Various	Various	FNS
8	- Affiliated			
9				
10	PJM Point to Point	Various	Various	LFP
11	Transmission Service -NonAffil			
12				
13	PJM Trans Owner Service Revenue	Various	Various	OLF
14	Wholesale Customer - NonAffil			
15				
16	PJM Transmission Owner	Various	Various	OLF
17	Admin Revenue - Non Affiliated			
18				
19	PJM Transmission Distribution	Various	Various	OS
20	& Metering - Non Affiliated			
21				
22	PJM Expansion Cost Recovery	Various	Various	OS
23				
24	RTO Formation Cost Recovery	Various	Various	OS
25				
26	PJM Power Factor Credits Revenue	Various	Various	OS
27	Wholesale Customers-NonAffil			
28				
29	PJM Transmission Enhancement	Various	Various	FNO
30	Revenue - Non Affiliated			
31				
32	PJM Transmission Enhancement	Various	Various	FNS
33	Revenue - Affiliated			
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 2011/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
						2
						3
PJM OATT	Various	Various				4
						5
						6
PJM OATT	Various	Various				7
						8
						9
PJM OATT	Various	Various				10
						11
						12
PJM OATT	Various	Various				13
						14
						15
PJM OATT	Various	Various				16
						17
						18
PJM OATT	Various	Various				19
						20
						21
PJM OATT	Various	Various				22
						23
PJM OATT	Various	Various				24
						25
PJM OATT	Various	Various				26
						27
						28
PJM OATT	Various	Various				29
						30
						31
PJM OATT	Various	Various				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 2011/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.
15,830,356			15,830,356	1
				2
				3
5,866,964			5,866,964	4
				5
				6
9,309,512			9,309,512	7
				8
				9
1,830,989			1,830,989	10
				11
				12
	81,596		81,596	13
				14
				15
	459,986		459,986	16
				17
				18
		528,232	528,232	19
				20
				21
328,320			328,320	22
				23
137,511			137,511	24
				25
		171,596	171,596	26
				27
				28
403,148			403,148	29
				30
				31
70,425			70,425	32
				33
				34
33,777,225	**541,582**	**699,828**	**35,018,635**	

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.: 19 Column: m

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

Schedule Page: 328 Line No.: 26 Column: m

Per Proforma ILDSA 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, 2011

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	1,095,064
18	American Electric Power Service Corporation **	Benton Harbor Service Center	8,917
19	Miscellaneous Lessees	Agricultural, Commercial, & Residential	96,468
20			
21			
22	Total Acct 454		1,200,449
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, 2011

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	210,011
13		
14	Acct 456 - Other Electric Revenues - Michigan	
15	Associated Business Development	205,554
16		
17	Adjustment of Insurance Proceeds	(7,000,000)
18		
19	Michigan Net Lost Revenue	1,194,612
20		
21	PJM/RTO Cost Recovery Items	4,362,305
22		
23		
24		
25		
26		
27		
28		
29		
30	TOTAL	(1,027,518)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	OS					7,816,222	7,816,222
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						7,816,222	7,816,222

FOOTNOTE DATA

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

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

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, 2011

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)	December 31, 2011

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)	Other (g)	Lessor (h)	Other (i)	Account Charged (j)	Remaining Annual Charges Under Lease Est. If Not Known (k)
		18,039				506	
		153,687				524	
		2,074				566	
		1,985				571	
		112,939				588	
		181,844				931	
		1,740				935	
		425				500	
		60,421				501	
		40,032				506	
		37,051				514	
		976,292				524	
		7,913				566	
		107,907				588	
		91,601				931	
		736				935	
		57,582				501	

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 December 31, 2011

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 December 31, 2011

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 December 31, 2011

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 December 31, 2011

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)	Other (g)	Lessor (h)	Other (i)	Account Charged (j)	Remaining Annual Charges Under Lease Est. If Not Known (k)
5,225,000	Real Estate taxes, assessments, maintenance, alterations, replacements and additions, insurance, and utilities.	537,500		1,183,277 1,808,390 2,517,082 111,802 698,760 6,530,705		567 588 589 921 184 931	1,746,875
44,668,660	Real Estate taxes, assessments, maintenance, alterations, replacements and additions, insurance, and utilities.	5,042,487		-22 1,801,102 4,829,851 4,561,517 2,450,128 6,325,888 67,645,848 5,479,250		506 566 567 588 589 921 931 184	24,372,018
	Maintenance, alterations, replacements, additions and insurance	69,197				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		1,628,143,606	26,654,952	507	207,430,565

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 December 31, 2011

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	
	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 December 31, 2011

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	
		74,625				931	
		56,173				931	
		35,526				935	
		33,945				935	
		53,188				931	
	Total Section A	81,852,919					

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 December 31, 2011

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 91-2 (Lease 3702) Railcars Trust 91-3 (Lease 00735) Railcars Trust 91-5 (Lease 00736) Railcars Trust 91-3 (Lease 4461) - Renewal of 00735 Railcars Trust 91-2 (Lease 4462) - Renewal of 3702	12/30/2014 09/30/2011 09/30/2011 12/30/2011 9/30/2016 9/30/2016
Citicorp North America, Inc	Cook Plant Warehouse, LPM9326, Ls# 3171 Date of Lease: 3/15/02	03/14/2012
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. FNBC Leasing Corp	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) 12/31/2011

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 December 31, 2011

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)
		142,951				107	
		915,554				152	
		2,321,997				184	
		758,928				417	
		90,546				107	
		71,917				152	
		7,384				184	
		681,097				184	
		38,054				417	
		2,505,955				184	
		1,433,228				186	37,895,118
		17,102				242	
12,271,945		2,087,290		11,787,435		186	32,049,928
8,220,826		1,120,983				186	3,365,854
12,047,760		1,687,411				186	(27,839)
3,254,280		439,949				186	(27,816)
13,871,080		2,083,779				186	(128,670)
4,379,951		61,888				186	1,187,024
17,637,125		250,898				186	4,778,203
	Real Estate taxes, assessments, maintenance, alterations, replacements and additions, insurance, and utilities.	195,697				163	
36,397,500		3,410,024		43,584,210		417	
19,030,575		1,495,524		19,028,664		417	
12,656,244		416,096		6,675,959		417	
9,035,000	Taxes except federal & state income, assessments	554,800		48,355,686		417	
6,547,335	operation and maintenance expenses, altering, replacements and additions, insurance, etc.	392,405					

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 December 31, 2011

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
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
RBS Asset Refinance	Water Transportation Equipment	06/23/2029

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 December 31, 2011

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					
		882,644					
		15,093					
		47,450					
		2,130,530					
		627,765					
		921,725					
		1,174,029					
		1,015,022					
		1,328,256					
		824,403					
	Total Section B	34,363,488					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	3,044,721
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	41,841
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	21,405
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Associated Business Development	1,310,830
7	American Electric Power Service Corp Billings	716,788
8	Nuclear Plant Insurance	891,945
9	Nuclear Plant replacement energy insurance refund	-1,621,198
10	Corporate Money Pool Allocations	106,278
11	Misc Financing and Legal Expenses	170,143
12	Corporate Contributions and Memberships	241,226
13	Cafeteria Subsidy Expenses	10,927
14	Labor Accruals	2,583
15	River Transport Division Expenses	-120
16	Intercompany Billings	-229,602
17	Minor Items	-46,060
18		
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46	TOTAL	4,661,707

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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			14,355,448		14,355,448
2	Steam Production Plant	26,858,213	741,939	3,834,387		31,434,539
3	Nuclear Production Plant	25,169,650	3,234,666			28,404,316
4	Hydraulic Production Plant-Conventional	1,080,527				1,080,527
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	17,216,274				17,216,274
8	Distribution Plant	35,878,370				35,878,370
9	Regional Transmission and Market Operation					
10	General Plant	2,069,036		983,159		3,052,195
11	Common Plant-Electric					
12	TOTAL	108,272,070	3,976,605	19,172,994		131,421,669

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 costs over a 5 year life totaling $13,745,096.

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	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2011/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	92,865			1.47		
14	311 - Rockport U2	3,996			3.38		
15	311 - Tanners CrkPlant	46,641			1.32		
16	311 - Tanners Precips	6,874			1.41		
17	312 - Rockport ACI	11,817			7.16		
18	312 - Rockport U1	396,401			1.70		
19	312 - Rockport U2	18,015			3.62		
20	312 - Tanners CrkPlant	363,213			2.48		
21	312 - Tanners Crk SNCR	14,152			7.07		
22	312 - Tanners Precips	76,225			1.42		
23	314 - Rockport U1	86,751			1.78		
24	314 - Rockport U2	772			4.05		
25	314 - Tanners CrkPlant	87,704			1.71		
26	315 - Rockport U1	57,776			1.55		
27	315 - Rockport U2	2,018			3.46		
28	315 - Tanners CrkPlant	18,898			1.34		
29	315 - Tanners Precips	7,885			1.41		
30	316 - Rockport U1	14,497			1.83		
31	316 - Rockport U2	6,775			3.71		
32	316 - Tanners CrkPlant	9,146			2.73		
33	316 - Tanners Precips	310			1.37		
34	TOTAL STEAM	1,322,731					
35							
36	NUCLEAR						
37	321 - Cook U1	77,023			0.67		
38	321 - Cook U2	249,312			1.03		
39	322 - Cook U1	521,322			1.40		
40	322 - Cook U2	645,914			1.15		
41	323 - Cook U1	231,704			0.98		
42	323 - Cook U2	192,900			0.89		
43	324 - Cook U1	76,286			0.92		
44	324 - Cook U2	86,791			0.98		
45	325 - Cook U1	27,886			1.45		
46	325 - Cook U2	138,034			1.52		
47	TOTAL NUCLEAR	2,247,172					
48							
49	HYDRO						
50	331 - Berrien Springs	451			1.79		

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2011/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			1.83		
13	331 - Constantine	272			1.72		
14	331 - Crew Service Cent	417			1.41		
15	331 - Elkhart	863			2.17		
16	331 - Mottville	424			2.45		
17	331 - Twin Branch	468			2.13		
18	332 - Berrien Springs	4,999			2.19		
19	332 - Buchanan	4,370			2.06		
20	332 - Constantine	963			2.04		
21	332 - Elkhart	4,033			2.47		
22	332 - Mottville	1,365			1.74		
23	332 - Twin Branch	3,231			1.50		
24	333 - Berrien Springs	7,125			2.97		
25	333 - Buchanan	1,292			2.17		
26	333 - Constantine	743			2.63		
27	333 - Elkhart	576			1.99		
28	333 - Mottville	568			2.23		
29	333 - Twin Branch	5,881			2.60		
30	334 - Berrien Springs	1,203			2.69		
31	334 - Buchanan	1,021			2.63		
32	334 - Constantine	369			3.56		
33	334 - Elkhart	451			2.27		
34	334 - Mottville	611			2.79		
35	334 - Twin Branch	1,623			2.55		
36	335 - Berrien Springs	672			2.68		
37	335 - Buchanan	225			2.57		
38	335 - Constantine	176			3.20		
39	335 - Crew Service Cent	127			1.35		
40	335 - Elkhart	183			2.88		
41	335 - Mottville	193			2.56		
42	335 - Twin Branch	396			2.64		
43	336 - Mottville	1			1.37		
44	TOTAL HYDRO	45,524					
45							
46	TRANSMISSION						
47	350 (Rights)	52,510	65.00		1.13	R5	
48	352	20,720	75.00		1.14	R4	
49	352 - City Lights Acq	31			5.26		
50	353	572,784	46.00	-24.00	1.45	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 2011/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	222,209	55.00	15.00	1.41	R5	
14	355	103,352	52.00	25.00	2.17	L1	
15	355 - City Lights Acq	69			5.62		
16	356	229,473	60.00	-5.00	1.20	R4	
17	356 - City Lights Acq	77			5.27		
18	357	1,483	50.00		1.40	R4	
19	357 - City Lights Acq	733			5.33		
20	358	4,841	57.00		1.32	R3	
21	358 - City Lights Acq	339			5.31		
22	359	350	65.00		1.50	R5	
23	TOTAL TRANSMISSION	1,209,265					
24							
25	DISTRIBUTION						
26	360 (Rights)	11,872	65.00		1.39	R5	
27	361	8,654	70.00		1.24	R2	
28	361 - City Lights Acq	312					
29	362	172,752	48.00	-10.00	1.64	R1	
30	362 - City Lights Acq	2,438					
31	363	5,488			6.67		
32	364	215,002	38.00	60.00	3.68	R0.5	
33	364 - City Lights Acq	553					
34	365	288,051	35.00	-25.00	1.73	R2.5	
35	365 - City Lights Acq	497					
36	366	60,685	55.00		1.61	R3	
37	366 - City Lights Acq	2,218					
38	367	175,484	38.00		2.30	L2	
39	367 - City Lights Acq	1,492					
40	368	256,284	30.00	-5.00	2.50	R2	
41	368 - City Lights Acq	68					
42	369	142,760	40.00	14.00	2.47	S0	
43	369 - City Lights Acq	2,261					
44	370	79,015	29.00	20.00	3.59	L0	
45	370 - City Lights Acq	199					
46	370.16	3,715			10.00		
47	371	20,017	14.00	20.00	7.10	L0	
48	371 - City Lights Acq	9					
49	373	18,404	20.00		2.27	S6	
50	TOTAL DISTRIBUTION	1,468,230					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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							
13	GENERAL PLANT						
14	390	36,147	40.00	-25.00	1.71	S0.5	
15	391	5,924	22.00	-15.00	3.37	R1.5	
16	393	37	14.00		5.64	L0.5	
17	394	8,992	16.00	-5.00	5.32	R0.5	
18	395	293	20.00		3.20	R1.5	
19	396	545	25.00		3.91	R1	
20	397	23,591	27.00	-30.00	2.27	R1.5	
21	397.16	335			10.00		
22	398	7,553	30.00	-15.00	2.50	R3	
23	TOTAL GENERAL PLANT	83,417					
24							
25	DEPRECIABLE SUM	6,376,339					
26							
27							
28							
29							
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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.: 25 Column: b

The depreciable plant base is the November 30, 2011 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.

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, 2011

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	619,126
9	Service Organizations	1,224,157
10	AEP Service Corp Contributions	166,027
11	Schools, Colleges, and Universities	190,791
12	Other minor items	(173,607)
13		
14	Subtotal 426.1	2,026,494
15		
16	426.3 PENALTIES	
17	Other minor items	26,853
18		
19		
20		
21	Subtotal 426.3	26,853
22		
23	426.4 EXPENDITURES FOR CERTAIN CIVIC, POLITICAL, AND RELATED ACTIVITY	
24	AEP Service Corp Expenses	962,889
25	Labor Overheads	73,352
26	Edison Electric Institute Dues	47,701
27	Business & Meeting Expenses	69,085
28	Legislative & Lobbying Services	41,000
29	Nuclear Energy Institute	21,630
30	Other Minor Items	(36,724)
31		
32	Subtotal 426.4	1,178,933
33		
34	426.5 OTHER DEDUCTIONS	
35	Factored Customer Accounts Receivable Expense	6,153,016
36	Allowance Losses	61
37	Blackhawk Coal Shutdown Costs	589,765
38	FAS 106-2 Medicare Subsidy	(74,090)
39	AEP Service Corp Expenses	241,424
40	Environmental Remediation Expense	(1,858)
41	Fort Wayne Settlement	3,480,365
42	Other minor items	248,241
43	Subtotal 426.5	10,636,924
44		
45	TOTAL 426	13,869,204

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, 2011

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	430 INTEREST ON DEBT TO ASSOCIATED COMPANIES	
2	Moneypool interest to AEP Utility Funding LLC	24,245
3		
4	TOTAL 430	24,245
5		
6	431 OTHER INTEREST EXPENSE	
7	Interest related to FIN-48 tax adjustments	(1,364,863)
8	Interest on Customer Deposits	1,635,368
9	Lines of Credit	1,759,457
10	Fuel Recovery	120,880
11	IPP Projects	86,660
12	Fort Wayne Settlement	349,758
13	Other minor items	348,414
14		
15		
16	TOTAL 431	2,935,674
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2011

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	123,364
2		
3	Misc items under 5% of total (6 items)	1,054
4		
5		
6		
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15		
16	**Total Acct 426.4**	**124,418**
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2011

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			
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			
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

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	1,591,233	497,771	2,089,004	
3	- Annual Fees	11,682,500	-2,392,000	9,290,500	
4	- Licensing Fees	332,180		332,180	
5					
6					
7	Indiana Rate Case		158,889	158,889	194,767
8	amortz 3/2009-3/2012				
9	per IURC Order #43306				
10					
11	Michigan Rate Case		122,619	122,619	235,020
12	amortz 12/2010-11/2012				
13	per MPSC Rate Case #U-16180				
14					
15	Misc Labor & Incentive accruals		3,093	3,093	
16					
17	Current Indiana Rate Case		226,346	226,346	
18					
19	Current Michigan Rate Case		281,132	281,132	
20					
21	Minor Items < $25,000		24,627	24,627	
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	13,605,913	-1,077,523	12,528,390	429,787

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	2,089,004					2
	928	9,290,500					3
	928	332,180					4
							5
							6
				928	158,889	35,878	7
							8
							9
							10
				928	122,619	112,401	11
							12
							13
							14
	928	3,093					15
							16
	928	226,346					17
							18
	928	281,132					19
							20
	928	24,627					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
		12,246,882			281,508	148,279	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 2011/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	8 items < $50,000
2		1 items < $50,000
3	A(1)e: Generation: Unconventional	2 items < $50,000
4		2 items < $50,000
5	A(2): Transmission	7 items < $50,000
6	A(2)a: Transmission: Overhead	1 item < $50,000
7	A(3): Distribution	3 items < $50,000
8	A(5): Environment (other than equipment)	Industrial Advisory Committee - Southern Company
9		4 items < $50,000
10	A(6): Other	2 items < $50,000
11		2 items < $50,000
12		3 items < $50,000
13		8 items < $50,000
14	A(6)f : Metering	1 item < $50,000
15	A(7) TOTAL COSTS INCURRED INTERNALLY	
16		
17	B(1) Research Support to Elec. Research	EPRI Nuclear Annual Research Portfolio
18		EPRI Annual Research Portfolio
19		EPRI Annual Research Portfolio
20		EPRI Annual Research Portfolio
21		EPRI Environmental Controls
22		EPRI Environmental Science
23		EPRI Water Research Center
24		39 items < $50,000
25		17 items < $50,000
26		5 items < $50,000
27	B(4) Research Support to Others	3 items < $50,000
28		2 items < $50,000
29	B(5) TOTAL COSTS INCURRED EXTERNALLY	
30		
31		
32		
33		
34		
35		
36		
37		
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 2011/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)		
44,844		506	44,844		1
10,248		524	10,248		2
8,851		506	8,851		3
11,186		588	11,186		4
13,621		566	13,621		5
30		566	30		6
-9,680		588	-9,680		7
214,710		506	214,710		8
8,932		506	8,932		9
6,584		506	6,584		10
9,390		524	9,390		11
9,588		566	9,588		12
34,762		588	34,762		13
4,016		588	4,016		14
367,082			367,082		15
					16
	1,308,570	524	1,308,570		17
	196,149	506	196,149		18
	100,530	566	100,530		19
	79,650	588	79,650		20
	137,246	506	137,246		21
	605,802	506	605,802		22
	87,444	506	87,444		23
	259,870	506	259,870		24
	48,973	566	48,973		25
	40,336	588	40,336		26
	15,161	566	15,161		27
	29,574	588	29,574		28
	2,909,305		2,909,305		29
					30
					31
					32
					33
					34
					35
					36
					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 2011/Q4

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	85,293,521		
4	Transmission	1,035,841		
5	Regional Market			
6	Distribution	8,423,386		
7	Customer Accounts	4,787,327		
8	Customer Service and Informational	1,788,954		
9	Sales			
10	Administrative and General	3,606,499		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	104,935,528		
12	Maintenance			
13	Production	51,610,676		
14	Transmission	3,172,265		
15	Regional Market			
16	Distribution	11,634,953		
17	Administrative and General	1,382,213		
18	TOTAL Maintenance (Total of lines 13 thru 17)	67,800,107		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	136,904,197		
21	Transmission (Enter Total of lines 4 and 14)	4,208,106		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	20,058,339		
24	Customer Accounts (Transcribe from line 7)	4,787,327		
25	Customer Service and Informational (Transcribe from line 8)	1,788,954		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	4,988,712		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	172,735,635	8,588,247	181,323,882
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 2011/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)	172,735,635	8,588,247	181,323,882
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	22,380,804	1,112,752	23,493,556
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	22,380,804	1,112,752	23,493,556
72	Plant Removal (By Utility Departments)			
73	Electric Plant	4,477,570	222,620	4,700,190
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	4,477,570	222,620	4,700,190
77	Other Accounts (Specify, provide details in footnote):			
78	120 - Nuclr Fuel in Proc of Refinmnt	350,981		350,981
79				
80				
81				
82	152 - Fuel Stock Undistributed	6,050,017		6,050,017
83				
84	163 - Stores Expense Undistributed	7,456,242	-7,456,242	
85				
86	183 - Prelim Survey	457	-457	
87	184 - Clearing Accounts	2,466,920	-2,466,920	
88	185 - ODD Temporary Facilities	51,352		51,352
89	186 - Misc Deferred Debits	2,404,029		2,404,029
90	188 - Research & Development	-1,893		-1,893
91	407 - Regulatory Debits			
92	417 - Misc Exp	21,294,331		21,294,331
93	426 - Political Activities	69,136		69,136
94				
95	TOTAL Other Accounts	40,141,572	-9,923,619	30,217,953
96	TOTAL SALARIES AND WAGES	239,735,581		239,735,581

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, 2011

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, 2011

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 $25,000, 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	24,764,282
	Retirement Work in Progress		108	1,129,623
	Nonutility Property		121	17,322
	Fuel Stock		151	(211)
	Fuel Stock Undistributed		152	2,427,154
	Clearing Accounts		163	1,336,998
	Regulatory Assets		182.3	485
	Preliminary Survey & Investig. Charges		183	687,196
	Clearing Accounts		184	94,456
	Misc Deferred Debits		186	181,051
	Deferred Debits-R&D		188	3,271,363
	Current & Accrued Liabilities		242	185
	Non-Utility Operations Revenue		417	1,213,121
	Misc Non-Operating Revenues		421	(177)
	Other Income Deductions		426	1,409,148
Electric	Account 401	Operating Expense	500	5,805,077
			501	142,546
			502	58,232
			505	(25)
			506	45,751
			507	14
			517	34,410
			524	989,881
			535	433,735
			537	17,085
			538	0
			539	578,113
			546	23,870
			547	(5)
			548	(13)
			549	1
			555	151,675
			556	1,747,208
			557	6,407,667
			560	1,771,743
			561	1,635,283
			562	57,490

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, 2011	
Electric	Account 401	Operating Expense (contd.)	563	16,394
			566	684,520
			580	1,439,246
			581	5,178
			582	25,662
			583	(1)
			584	21,489
			585	4
			586	365,571
			588	1,326,326
			589	9
			901	457,770
			902	175,179
			903	13,417,378
			905	83,888
			907	426,102
			908	140,600
			909	225
			910	23
			911	37
			912	5
			920	20,393,755
			921	1,787,715
			923	22,296,665
			924	19,098
			925	27,202
			926	185,438
			928	192,787
			930	995,729
			931	13,393
Electric	Account 401	Total Operating Expense		84,397,125
Electric	Account 402	Maintenance Expense	510	849,810
			511	21,277
			512	947,423
			513	1,728,586
			514	132,503
			528	128,671
			530	885,789
			531	2,507
			532	21
			541	97,807
			542	1,882
			543	1,283
			544	13,269
			545	3,017
			553	(20)
			568	96,340
			569	719,009
			570	301,228
			571	381,408
			572	1,491
			590	8,743
			591	7,978
			592	143,545
			593	97,270
			594	120
			595	141
			597	93
			935	38,959
Electric	Account 402	Total Maintenance Expense		6,610,152
		Total O&M		91,007,276
		Total AEP Service Corp charges		$ 127,539,272

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, 2011

Charges for Outside Professional & Other Consulting Services - Payments of $25,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
A P SERVICES INC	plant equipment repair services	Invoice Cost	512	33,835
203 ARMSTRONG DRIVE			513	14,977
FREEPORT, PA 16229				48,812
ACRT INC	environmental consulting services	Invoice Cost	107	61,706
1333 HONE AVENUE			571	20,810
AKRON, OH 43310			593	97,513
				180,029
ADT SECURITY SERVICES INC	building security systems	Invoice Cost	107	36,935
various US locations			506	1,822
			591	314
				39,071
ADVANCED ENERGY SOLUTIONS LLC	industrial contracting services	Invoice Cost	107	458,104
3108 MOCKINGBIRD LANE			108	201,232
EVANSVILLE, IN 47710				659,336
ADVANCED INDUSTRIAL MACHINING	nuclear plant equipment rental	Invoice Cost	107	42,124
30 DILLMONT DRIVE #286			108	23,384
WORTHINGTON, OH 43235				65,509
ADVANTAGE STAFFING INC	temporary staffing services	Invoice Cost	107	6,027
112 N WASHINGTON ST			152	329,922
DALE, IN 47523			504	293,041
			506	340,849
			511	20,410
			513	6,356
				996,606
AERIAL SOLUTIONS INC	tree trimming services	Invoice Cost	571	74,152
7074 RAMSEY FORD ROAD				74,152
TABOR CITY, NC 28463				
AEROTEK INC	equipment & maintenance services	Invoice Cost	107	19,438
7301 PARKWAY DRIVE			108	4,436
HANOVER, MD 21076			186	18,153
			595	30,820
				72,847
ALL CITIES OCCUPATIONAL & ENV	nuclear plant support staffing	Invoice Cost	524	62,817
3333 S. STATE STREET				62,817
SAINT JOSEPH, MI 49085				
ALL CRANE & EQUIPMENT RENTAL	equipment rental services	Invoice Cost	107	51,624
5725 KENNEDY			108	186
HAMMOND, IN 46323			571	186
				51,996
ALSTOM POWER INC	inspection & measurement services	Invoice Cost	107	34,753
2800 WATERFORD LAKE DR			512	15,421
MIDLOTHIAN, VA 23112			513	323,613
				373,788
AMERICAN ENERGY PRODUCTS	utility pole inspection services	Invoice Cost	107	80,262
1105 INDUSTRIAL STREET			108	8,918
LANSING, KS 66043				89,180
AMERICAN SERVICE GROUP INC	elevator repair & inspection services	Invoice Cost	107	30,984
7149 STATE ROUTE 54			512	4,810
PHILPOT, KY 42366				35,795

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NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
ADVANTAGE STAFFING INC	employee staffing services	Invoice Cost	107	6,688
575 5TH AVENUE			108	557
NEW YORK, NY 10116			186	693,704
			571	1,191
			583	86
			588	108,539
			593	17,427
			594	1,086
			595	286
				829,563
ASHER AGENCY INC	marketing services	Invoice Cost	908	49,667
535 W. WAYNE STREET			924	1,250
FORT WAYNE, IN 46801				50,917
ASPLUNDH CONSTRUCTION CORP	construction contracting services	Invoice Cost	108	6,946
950 TAYLOR STATION ROAD.			185	108,591
COLUMBUS, OH 43230			186	10,424,067
			563	79,447
			583	4,506
			584	462
			588	18,039
			593	39,964
			594	67,792
			586	122,948
			930	271,424
				11,144,185
ASPLUNDH TREE EXPERT CO	tree trimming services	Invoice Cost	107	7,026,155
720 OSAGE STREET			186	5,875
FORT WAYNE, IN 46808			571	189,768
			593	11,177,138
			930	409,235
				18,808,171
B & S AIR INC	reforestation services	Invoice Cost	571	127,685
416 BROAD STREET				127,685
LUMPKIN, GA 31815				
B C WELDING INC	fabrication & insulation services	Invoice Cost	107	52,154
12801 INDUSTRIAL PARK DRIVE			108	4,678
GRANGER, IN 46530			539	6,195
			543	7,755
			544	22,129
			545	1,770
				94,681
BABCOCK & WILCOX CO	plant equipment repair services	Invoice Cost	107	50,500
20 S. VAN BUREN DRIVE			512	179,554
BARBERTON, OH 44203				230,054
BANTA ELECTRICAL CONTRACTORS	electrical maintenance svcs	Invoice Cost	107	45,187
5701 ST RT 128			108	13,219
CLEVES, OH 45002				58,406
BJ PROCESS & PIPELINE SVCS	boiler cleaning services	Invoice Cost	107	473,214
414 PINCKNEY				473,214
HOUSTON, TX 77249				
BLACK & VEATCH	nuclear plant consultants	Invoice Cost	107	25,671
11401 LAMAR AVE				25,671
OVERLAND PARK, KS 66211				
BLUEGRASS CENTRAL CONSTRUCTION	electrical contracting services	Invoice Cost	186	49,761
265 MIDLAND TRAIL				49,761
MT. STERLING, KY 40353				
BOSE PUBLIC AFFAIRS	legislative services	Invoice Cost	921	51,792
1600 FIRST INDIANA PLAZA				51,792
INDIANAPOLIS, IN 46204				

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NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
BROOKS CONSTRUCTION CO INC 6525 ARDMORE AVENUE FORT WAYNE, IN 46809	general construction services	Invoice Cost	107 108	194,022 25,000 219,022
BROWN ELECTRIC CO INC 1100 CHARLES AVE DUNBAR, WV 25064	electrical construction svcs.	Invoice Cost	107 108 183 930 935	806,137 52,174 43,179 11,837 2,892 916,218
BULDOG DIVING INC 2968 WEST COUNTY RD 300 SOUTH ROCKPORT, IN 47635	commercial diving services	Invoice Cost	512	30,701 30,701
BURNS & MCDONNELL 9400 WARD PARKWAY KANSAS CITY, MO 64114	engineering & consulting services	Invoice Cost	107	883,872 883,872
CARBON STEEL INSPECTION INC 755 WILLIAM PITT WAY PITTSBURGH, PA 15238	testing services	Invoice Cost	512	72,000 72,000
CENTRIFUGAL TECHNOLOGY INC 330 CENTECH DRIVE HICKORY, KY 42051	equipment parts & services	Invoice Cost	514	40,472 40,472
CFM/VR TESCO INC 1875 FOX LANE ELGIN, IL 60123	valve repairs	Invoice Cost	512 513	346,898 11,651 358,548
CHAMNESS LAND SURVEYING 588 SOUTH, 600 WEST ROCKPORT, IN 47635	surveying services	Invoice Cost	107 186 501	46,500 8,248 1,045 55,793
CMS ROOFING 3920 BUTLER ROAD FORT WAYNE, IN 46898	commercial roofing services	Invoice Cost	107	30,000 30,000
COMMONWEALTH ASSOCIATES INC 2700 W ARGYLE JACKSON, MI 49204	electrical engineering & design services	Invoice Cost	107	431,207 431,207
COMMUNICATION COUNSEL OF AMERICA 17400 DALLAS PKWY STE 200 DALLAS, TX 75287	legal (rate case filings)	Invoice Cost	186 923	164,647 42,106 206,754
CONTXT CORPORATION 28276 KENSINGTON LANE PERRYSBURG, OH 43551	management consulting services	Invoice Cost	921 923	25,000 46,401 71,401
CULY CONSTRUCTION 5 INDUSTRIAL PARK DRIVE WINCHESTERM IN 47394	drainage construction services	Invoice Cost	107 108 562 570 592	24,962 1,265 12,073 7,090 5,833 51,222
CUSTOM MECHANICAL CONSTRUCTION 1609 ALLENS LANE EVANSVILLE, IL 47710	construction contracting services	Invoice Cost	513	71,555 71,555
DAVEY RESOURCE GROUP 3728 FISHCREEK ROAD STOW, OH 44224	tree trimming services	Invoice Cost	107 571	10,944 143,502 154,446

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NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
DAY & ZIMMERMAN NPS INC 1827 FREEDOM RD LANCASTER, PA 17601	nuclear engineering support	Invoice Cost	107	1,839,633
			108	395,525
			520	31,777
			524	25,501
			529	182,422
			530	10,619,285
			531	2,152,907
			532	2,617,965
				17,865,016
DEARBORN CRANE & ENGINEERING 1133 EAST 5TH STREET MISHAWAKA, IN 46544	underground pipe location services	Invoice Cost	107	29,833
			108	8,639
			545	4,445
				42,917
DELUXE GLASS OF FORT WAYNE INC 610 E. STATE BLVD. FORT WAYNE, IN 46805	glass repairs services	Invoice Cost	107	37,000
			108	1,800
				38,800
DEVELOPMENT COUNSELLORS INTERNAT'L 215 PARK AVENUE SOUTH, 10TH FLOOR NEW YORK, NY 10003	marketing services	Invoice Cost	912	41,603
				41,603
DIGIOIA, GRAY & ASSOCIATES 570 BEATTY ROAD MONROEVILLE, PA 15146	engineering services	Invoice Cost	107	30,105
				30,105
E & T TREE SERVICE 125 MT AUBURN ST DUNKIRK, IN 47336	landscaping & tree removal services	Invoice Cost	107	49,044
			184	7,620
			562	480
			570	520
			935	1,520
				59,184
ECS SOLUTIONS INC 2616 KOTTER AVENUE EVANSVILLE, IN 47715	coal handling system design	Invoice Cost	107	160,060
				160,060
EDKO LLC 908 S. 11TH STREET BROKEN ARROW, OK 74012	perimeter security services	Invoice Cost	107	1,584,000
			593	189,721
				1,773,721
ELECTRIC POWER GROUP LLC 201 SOUTH LAKE AVE., SUITE 400 PASADENA, CA 91101	strategic consulting services	Invoice Cost	107	61,500
				61,500
EMERGENCY RADIO SERVICE INC 4410 EARTH DR FORT WAYNE, IN 46809	radio tower repairs & inspection	Invoice Cost	107	152,150
				152,150
EMERSON PROCESS LLP 835 INNOVATION DR KNOXVILLE, TN 37932	software / hardware support	Invoice Cost	513	26,278
				26,278
ENERFAB INC 4955 SPRING GROVE CINCINNATI, OH 45232	fabrication & Installation services	Invoice Cost	107	8,203,483
			108	6,281,677
				14,485,160
ENGART AMERICA INC 150 STANAFORD RD BECKLEY, WV 25802	plant equipment maintenance	Invoice Cost	107	451,432
				451,432
E & T TREE SERVICE 125 MT. AUBURN STREET DUNKIRK, ON 47336	landscaping & tree removal services	Invoice Cost	107	66,820
			108	88
			186	3,975
			566	12,603
			571	17,630
				101,115

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ENVIRO-CLEAN INC	carpet cleaning services	Invoice Cost	184	30,059
5520 DISTRIBUTION DR			931	471
FT WAYNE, IN 46825			935	496
				31,026
ENVIRONMENTAL REMEDIATION SVCS.	emergency cleanup services	Invoice Cost	108	3,123
4010 OPTION PASS			186	36,656
FT WAYNE, IN 46818			580	36,120
			588	6,689
				82,589
EQ - THE ENVIRONMENTAL QUALITY CO	plant equipment cleaning services	Invoice Cost	107	29,871
36255 MICHIGAN AVENUE			108	11,966
WAYNE, MICHIGAN 48184				41,837
FAIRCHILD COMMUNICATIONS	fire alarm system installation services	Invoice Cost	107	63,135
3185 N. SHADELAND				63,135
INDIANAPOLIS, IN 46226				
FINANCIAL CONCEPTS & APPLICATIONS	financial consulting firm	Invoice Cost	186	40,961
3907 RED RIVER				40,961
AUSTIN, TX 78751				
FORT WAYNE ROOFING & SHEET METAL	roofing services	Invoice Cost	107	425,650
4320 ARDMORE AVENUE			108	24,000
FORT WAYNE, IN 46802				449,650
FURMANITE AMERICA	equipment repair & heat treaments	Invoice Cost	107	11,280
1931 NORTH WIND PARKWAY			512	29,948
HOBART, IN 46342				41,228
G & L CORPORATION	equipment moving services	Invoice Cost	107	289,500
3101 BROOKLYN AVE			108	30,883
FORT WAYNE, IN 46809			570	5,747
				326,129
G4S SECURE SOLUTIONS (USA) INC	security services	Invoice Cost	107	21,498
4200 WACKENHUT DR			108	2,309
PALM BEACH GARDENS, FL 33410			184	749
			506	41,554
			591	5,741
				71,851
GAYLOR INC	electrical contracting services	Invoice Cost	107	36,871
5750 CASTLE CREEK PKWY N DRIVE			108	7,025
INDIANAPOLIS, IN 46250				43,896
GENERAL ELECTRIC INTL. INC.	plant outage support & inspection services	Invoice Cost	107	103,500
various US locations				103,500
GENEREX INC	equipment removal & replacement	Invoice Cost	107	71,644
3403 E WASHINGTON BLVD			108	500
FORT WAYNE, IN 46885			591	6,122
				78,266
GLOBAL INSULATION INC	plant maintenance	Invoice Cost	108	88,211
1501 RAFF RD SW				88,211
CANTON, OH 44710				
GOOD CENTS	marketing & technology solutions	Invoice Cost	908	386,584
10350 BLUEGRASS PARKWAY				386,584
LOUISVILLE, KY 40299				
GOOD KARMA CONSULTING INC	market research services	Invoice Cost	923	31,000
440 RIDGEWAY				31,000
ST. JOSEPH, MI 49085				

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NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
GOTH & SONS EXCAVATING INC 5611W CR 500N MUNCIE, IN 47304	substation construction & repair services	Invoice Cost	107 562 571 582	143,233 17,664 1,692 729 163,317
GRANT TOWER INC 13064 WISNER AVENUE GRANT, MI 49327	installation & repair services	Invoice Cost	930	43,338 43,338
GROVES, WILLIAM E CONSTRUCTION INC 3135 GRAPEVINE ROAD MADISONVILLE, KY 42431	power line construction servies	Invoice Cost	186	251,667 251,667
GUS COMMERCIAL DIVERS LLC 12839 INDUSTRIAL PARK DR. GRANGER, IN 46530	underwater construction services	Invoice Cost	543 544	160,439 2,986 163,424
H C NUTTING 611 LUNKEN PARK DR CINCINNATI, OH 45226	concrete testing services	Invoice Cost	107 186	106,234 13,470 119,704
HAVERFIELD INTERNATIONAL INC 1750 EMMITSBURG ROAD GETTYBURG, PA 17325	aerial inventory inspections	Invoice Cost	571	216,076 216,076
HELICOPTER MINIT-MEN INC 3136 TRABUE ROAD COLUMBUS, OH 43204	helicopter services	Invoice Cost	107 571	18,890 250,372 269,263
HELICOPTERS SOUTHWEST 2 COLONIAL DRIVE TAXARKANA, AR 71854	helicopter services	Invoice Cost	571	36,564 36,564
HENRY, ROBERT CORP 404 S. FRANCIS STREET SOUTH BEND, IN 46617	drain installation	Invoice Cost	107 108 186 572 584 588 583 594 596	163,166 28,885 571,737 38,660 3,086 4,051 3,673 91,526 6,574 911,358
HOLTEC INTERNATIONAL 555 LINCOLN DRIVE WEST MARLTON, NJ 08053	nuclear plant dry cask storage project	Invoice Cost	165	258,860 258,860
HOOSIER HELICOPTER SERVICES 7900 N. THAMES DRIVE BLOOMINGTON, IN 47408	helicopter services	Invoice Cost	563 571	105,931 32,881 138,812
HOUSTON, R & SON SANDBLASTING 115 MAY DRIVE HARRISON, OH 45030	sandblasting services	Invoice Cost	107 512 513	2,868 562 30,909 34,339
HVB AE POWER SYSTEMS INC 7250 MCGINNIS FERRY ROAD SUWANEE, GA 30024	electrical equipment sales	Invoice Cost	107	26,070 26,070
IJUS LLC 560 OFFICENTER PLACE GAHANNA, OH 43230	pole attachment evaluation	Invoice Cost	186 566	262,820 641 263,461
INDIANA COMMUNITY ACTION ASSC 1845 W. 16TH STREET INDIANAPOLIS, IN 46202	residential low income weatherization project	Invoice Cost	908	168,319 168,319

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NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
INDIANA EQUITIES	building maintenance services	Invoice Cost	184	4,984
605 FRONT STREET, SUITE 200			935	37,038
COLUMBUS, OH 43215				42,021
INDUSTRIAL CONTRACTORS INC	equipment repairs	Invoice Cost	107	7,092,080
1001 BUCHANAN ROAD			108	2,960,831
EVANSVILLE, IN 47720			152	619,816
			186	657,960
			186	193,258
			506	182,510
			511	827,959
			512	11,277,513
			513	1,545,651
			514	468,386
			569	31,291
			570	12,807
			935	1,876
				25,871,937
INSERV INC	building maintenance services	Invoice Cost	107	11,018
1604 RUPEL ST			108	92,477
SOUTH BEND, IN 46628			186	1,165
			570	6,252
			588	27,435
				138,346
IRON MOUNTAIN	records storage	Invoice Cost	925	47,077
1137 BRANCHTON RD				47,077
BOYERS, PA 16020				
JACO ENVIRONMENTAL INC	recycling services	Invoice Cost	908	392,498
various US locations				392,498
JF ELECTRIC INC	electrical contracting services	Invoice Cost	186	125,779
100 LAKEFRONT PARKWAY				125,779
EDWARDSVILLE, IL 65025				
J F NEW & ASSOCIATES	archaeological site evaluation	Invoice Cost	107	35,332
11156 LUSCHEK DR			183	2,535
CINCINNATI, OH 45241			186	19,327
			537	10,722
			539	9,367
				77,283
JOINT FIELD SERVICES INC	nuclear plant support services	Invoice Cost	107	45,037
1020 BROADWAY ST			108	564
MARSEILLES, IL 61341			530	7,706
				53,307
KEITH FIRE EXTINGUISHER SERVICE	fire extinguisher inspection	Invoice Cost	514	59,458
601 S HIGH ST				59,458
RISING SUN, IN 47040				
KEMNA SERVICES INC	office building repairs	Invoice Cost	908	91,271
P O BOX 1043				91,271
INDIANAPOLIS, IN 46071				
KENRICH GROUP LLC	legal services (liability claims)	Invoice Cost	923	160,175
1250 CONNECTICUT AVE NW				160,175
WASHINGTON, DC 20036				
KENT POWER INC	power line relocation	Invoice Cost	107	1,793,150
90 SPRING STREET			108	228,126
KENT CITY, MI 49330			186	236,721
			513	88,268
			571	60,905
				2,407,170

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NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
KLIPPERS LAWNCARE SERVICES 57519 O KEEFE ROAD CASSOPOLIS, MI 49031	landscaping services	Invoice Cost	539	49,365 49,365
LANDSCAPE SOLUTIONS GROUP INC 52041 PATRICIA LANE SOUTH BEND, IN 46628	landscaping services	Invoice Cost	107 108 184 186 563 588 594	2,120 6,385 3,738 9,662 6,535 35,092 685 64,217
LAPORTE CONSTRUCTION 512 H STREET LAPORTE, IN 46352	excavation & site preparation	Invoice Cost	107 542 543	6,530 2,530 546,016 555,076
MANPOWER various US locations	temporary staffing services	Invoice Cost	107 108 163 186 580 595 930	96,976 7,209 420 125 31,951 12,735 75 149,490
MANWEB SEVICES 11800 EXIT FIVE PARKWAY FISHERS, IN 46037	temporary staffing services	Invoice Cost	107	28,253 28,253
MARINE SOLUTIONS INC 250 GOLD RUSH DR LEXINGTON, KY 40503	underwater construction & inspection	Invoice Cost	107	82,000 82,000
MARSHALL & STEVENS INC ONE CIVIS PLAZA, SUITE 100 CARSON, CA 90745	appraisal services	Invoice Cost	506	56,212 56,212
MARTELL ELECTRIC LLC 4601 CLEVELAND RD SOUTH BEND, IN 46628	electrical construction & repairs	Invoice Cost	107 935	15,856 2,701 18,557
MATERIALS HANDLING 693 PLYMOUTH NE GRAND RAPIDS, MI 49505	nuclear plant dry cask & storage	Invoice Cost	107 108	1,053 26,361 27,414
MEAD & WHITE ELECTRIC INC 9895 RED ARROW HIGHWAY BRIDGMAN, MI 49106	electrical construction services	Invoice Cost	107 108 537 544 545	45,054 4,801 1,798 9,984 8,972 70,610
MICHIANA LAND SERVICES INC 505 PLEASANT ST ST JOSEPH, MI 49085	land right of way services	Invoice Cost	107 108 563 566 571 592	406,367 1,216 4,887 23,029 12,478 383 448,360
MICHIGAN COMMUNITY ACTION AGENCY 2173 COMMONS PARKWAY OKEMOS, MI 48864	energy optimization project	Invoice Cost	908	2,706,738 2,706,738
MICHIGAN PAVING & MATERIALS CO 2575 HAGGERTY ROAD CANTON, MI 48188	paving services	Invoice Cost	107 108	236,215 40,000 276,215

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MIDWEST ENERGY EFFICIENCY ALLIANCE 20 NORTH WACKER, SUITE 1301 CHICAGO, IL 60606	annual conference	Invoice Cost	908	106,432 106,432
MILLER CONSTRUCTION CO 518 SOUTH FIFTEENTH STREET VINCENNES, IN 47591	excavation & site preparation	Invoice Cost	107 513	7,304 73,402 80,706
MISHAWAKA UTILITIES 126 NORTH CHURCH STREET MISHAWAKA, IN 46544	utilities provider services	Invoice Cost	107 539	37,728 3,263 40,991
MOFFITT REHAB SERVICES INC 200 PARK ROAD HAWESVILLE, KY 42348	excavation & site preparation	Invoice Cost	107 501	1,104 744,878 745,981
MORAN, F E INC 2265 CARLSON DR NORTHBROOK, IL 60062	plant equipment construction & repairs	Invoice Cost	108	68,550 68,550
MPW ENVIRONMENTAL SERVICES 9711 LANCASTER RD SE HEBRON, OH 43025	plant equipment maintenance & cleaning	Invoice Cost	107 108 152 501 511 512 513	64,033 101,169 32,946 29,119 206,622 332,156 3,578 769,622
MUCHMORE HARRINGTON SMALLEY 124 WEST ALLEGAN ST LANSING, MI 48933	legislative services	Invoice Cost	426	42,000 42,000
MYERS L E CO 22386 NETWORK PLACE CHICAGO, IL 60673	electrical construction services	Invoice Cost	107 108	186,649 172 186,821
NAVIGANT CONSULTING INC 110 E. WAYNE STREET FORT WAYNE, IN 46802	management consulting services	Invoice Cost	908	211,419 211,419
NELSON TREE SERVICE INC 3300 OFFICE PARK DRIVE DAYTON, OH 45439	tree trimming services	Invoice Cost	107 571	124,694 708,754 833,448
NESCO SALES & RENTALS 4121 SOLUTIONS CENTER CHICAGO, IL 60677	plant equipment maintenance	Invoice Cost	107 560 563	35,532 9,712 1,350 46,594
NEWKIRK ELECTRIC ASSOCIATES 1875 ROBERTS STREET MUSKEGON, MI 49442	electrical construction services	Invoice Cost	107 108	1,656,404 118,967 1,775,371
NORTH AMERICAN SIGNS INC 3601 WEST LATHROP SOUTH BEND, IN 46628	signage services	Invoice Cost	107 108	26,109 500 26,609
NURSING CORPS INC 500 LURAY DRIVE WINTERSVILLE, OH 43953	employment services	Invoice Cost	107	115,265 115,265
OJS BUILDING SERVICES INC 1008 LINCOLN WAY E SOUTH BEND, IN 46601	plumbing & sewer repairs	Invoice Cost	107 186	52,914 873 53,787

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NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
ONE LUCKY GUITAR INC	marketing product developer	Invoice Cost	912	9,092
1301 LAFAYETTE ST			921	4,295
FORT WAYNE, IN 46802			923	18,647
				32,034
ONE WAY TREE SERVICES	tree trimming services	Invoice Cost	107	30,800
5933 HUNTER ROAD				30,800
BOONVILLE, IN 47601				
OTIS ELEVATOR COMPANY	elevator repair & inspection services	Invoice Cost	511	28,805
622 E MARKET ST			935	776
INDIANAPOLIS, IN 46202				29,581
P & RO SOLUTIONS INC	software maintenance fees	Invoice Cost	502	5,010
30 BETHEL ROAD			510	49,992
GLEN MILLS, PA 19342			512	8,000
				63,002
PARKLINE INC	prefabricated metal building	Invoice Cost	107	279,017
4224 SCOTTSDALE ROAD				279,017
ST JOESEPH, MI 49085				
PARKS DRILLING CO	drilling services	Invoice Cost	107	193,627
5745 AVERY ROAD				193,627
DUBLIN, OH 43016				
PERFORMANCE IMPROVEMENT INTL	engineering consulting svcs	Invoice Cost	517	45,600
2111 S EL CAMINO REAL				45,600
OCEANSIDE, CA 92054				
PERRY BALLARD INC	nuclear plant PR & media support services	Invoice Cost	921	204,863
526 UPTON DR E			923	31,600
ST JOSEPH, MI 49085				236,463
PIKE ELECTRIC INC	electrical contracting services	Invoice Cost	186	269,157
2080 COVINGTON PIKE				269,157
MEMPHIS, TN 38148				
POOLED EQUIPMENT INVENTORY CO	electrical equipment sales	Invoice Cost	163	128,887
3988 LORNA ROAD				128,887
BIRMINGHAM. AL 35202				
PRECISION SERVICES	blasting services	Invoice Cost	512	129,099
PO BOX 785				129,099
FLATWOODS, KY 41139				
PUBLIC UTILITIES SERVICES, INC	electric tower painting	Invoice Cost	571	856,267
212-26 99TH AVENUE				856,267
QUEENS CITY, NY 11429				
PULVERIZER SERVICES, INC	plant equipment rebuilding services	Invoice Cost	107	5,000
200 PARK LOOP			108	3,350
CALHOUN, KY 42327			512	424,846
				433,196
RANDSTAD TECHNOLOGIES LP	IT staffing services	Invoice Cost	107	56,363
555 NORTH POINT CENTER EAST				56,363
ATLANTA, GA 30384				
REVENEW INTERNATIONAL LLC	cost recovery solutions services	Invoice Cost	107	34,630
14100 SOUTHWEST FREEWAY, SUITE 320				34,630
SUGAR LAND, TX 77478				
REYNOLDS INC	water system services	Invoice Cost	107	25,147
25866 NETWORK PLACE				25,147
CHICAGO, IL 60673				

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Charges for Outside Professional & Other Consulting Services - Payments of $25,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
RILEY POWER INC 5 NEPONSET STREET WORCESTER, MA 01606	electrical services	Invoice Cost	107	351,957 351,957
ROBINSON SERVICE INC 4801 COMMERCE DRIVE TRUSSVILLE, AL 35173	plant equipment inspection services	Invoice Cost	107	36,126 36,126
SAFWAY SERVICES LLC 3200 SHEFFIELD AVE HAMMOND, IN 46327	equipment rental	Invoice Cost	107 529 530 531	43,323 12,810 231,695 63,891 351,720
SARGENT & LUNDY LLC 55 E MONROE ST CHICAGO, IL 60603	nuclear engineering services	Invoice Cost	107 524 530	73,429 6,506 114,552 194,487
SHAW CONSULTANTS INTL. CHICAGO, IL 60694	appraisal consulting services	Invoice Cost	186 588	186,842 1,522 188,364
SLATILE ROOFING & RESTORATION 1703 SOUTH IRONWOOD SOUTH BEND, IN 46613	roofing installation & repairs	Invoice Cost	542 544	5,739 25,796 31,535
SOUTHWEST TRANSPORT CO 137 HILLSBOROUGH ST HARTFORD, MI 49057	snow removal services	Invoice Cost	108 588 935	14,734 10,717 879 26,330
STAFFMARK INC 10154 PRINCETON-GLENDALE ROAD CINCINNATI, OH 45246	temporary staffing services	Invoice Cost	163	30,726 30,726
STERETT CONSTRUCTION CO 34 BOOTH FIELD ROAD OWENSBORO, KY 42301	crane services	Invoice Cost	512 514	11,379 36,350 47,729
SUMMIT ENVIRONMENTAL SERVICES 2125 GLENVIEW DRIVE EVANSVILLE, IN 47720	environmental consulting services	Invoice Cost	107 108	25,143 24,761 49,904
SUN TECHNICAL SERVICES INC 6490 S MCCARRAN BLVD RENO, NV 89509	engineering services	Invoice Cost	107 108 163 183 186 500 501 506 512 513 514 517 529 530 545	830,238 28,315 23,212 9,709 9,733 33,561 76,058 8,806 1,956 18,024 1,348 2,454 686 28,661 742 1,073,503
SWITCHGEAR SOLUTIONS 2540 N. JACKRABBIT AVENUE TUCSON, AZ 85745	plant equipment installation	Invoice Cost	107	157,834 157,834
T & W VALVE AND MACHINE CO 2501 GRIMES AVENUE OWENSBORO, KY 42303	industrial machine repair services	Invoice Cost	512	45,845 45,845

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Charges for Outside Professional & Other Consulting Services - Payments of $25,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
T&A TRUCKING	trucking services	Invoice Cost	107	244,256
2754 PINE DRIVE NE			108	11,442
NEW PHILADELPHIA, OH 44663			513	4,638
			570	1,554
			592	1,847
				263,738
TECHSERV CONSULTING & TRAINING LTD	nuclear plant project support services	Invoice Cost	107	3,964
3320 SSW LOOP 323			563	7,626
TYLER, TX 75701			571	53,595
				65,185
TEMPORARY TECHNICAL SERVICES	temporary staffing services	Invoice Cost	107	108,254
915 AIRPORT RD			108	22,985
JACKSON, MI 49202			186	78,097
			580	28,689
			588	7,708
			590	7,932
			593	15,700
				269,363
TIP TOP INDUSTRIAL SERVICE INC	machine repairs	Invoice Cost	107	93,293
4690 ASHLEY DR			108	8,507
HAMILTON, OH 45011			512	159,939
			513	3,732
				265,471
TOLEDO CAISSON CORPORATION	construction contracting services	Invoice Cost	107	75,106
6275 CONSEAR ROAD				75,106
OTTAWA LAKE, MI 49267				
TOWNSEND CORPORATION	brush & tree trimming services	Invoice Cost	562	20,539
101 S MAIN ST			582	28,737
PARKER CITY, IN 47368				49,276
TRI STATE FENCE CO INC	fence construction services	Invoice Cost	186	37,535
1516 N. MAIN STREET				37,535
EVENSVILLE, IL 47711				
UC SYNERGETIC INC	plant engineering support	Invoice Cost	107	251,946
3440 LAKEMONT BLVD			108	22,295
FORT MILL, SC 29708			186	6,779
			580	3,269
			588	7,219
			590	2,334
			593	9,052
				302,894
UNDERWATER CONSTRUCTION CORP	underwater construction services	Invoice Cost	107	35,959
110 PLAINS RD			513	2,585
ESSEX, CT 06426			532	71,629
			543	36,584
				146,757
UNITED CONSTRUCTION CO INC	construction contracting services	Invoice Cost	107	1,146,981
1340 OLD ROSEMAR ROAD			108	161,502
PARKERSBURG, WV 26104			183	33,164
			500	530
			512	45,649
			545	25,656
				1,413,482
UNITED KISER SERVICES LLC	commercial building construction services	Invoice Cost	107	251,787
1001 STEPHENSON STREET			108	83,643
NORWAY, MI 49870			544	16,635
				352,065

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Charges for Outside Professional & Other Consulting Services - Payments of $25,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
UNITED RENTALS various US locations	equipment rental	Invoice Cost	107	5,279
			512	15,008
			513	11,240
			514	7,211
			570	1,686
				40,424
UNIVERSAL INCORPORATED STATE ROUTE 2 NEW MARTINSVILLE, WV 26155	equipment tubing repair services	Invoice Cost	107	10,434
			108	9,486
			511	30,500
			512	9,010
			513	35,598
			514	12,066
				107,094
UTILITIES SERVICE ALLIANCE INC 9200 INDIAN CREEK PARKWAY OVERLAND PARK, KS 66210	nuclear plant support staffing	Invoice Cost	107	137,496
				137,496
UTILITY LOCATORS various US locations	power line construction services	Invoice Cost	584	1,336,945
				1,336,945
UTILITY RISK MANAGEMENT CORP 2038 MOUNTAIN ROAD STOWE, VT 05672	power line construction services	Invoice Cost	571	971,380
				971,380
VARO ENGINEERS INC 2751 TULLER PARKWAY, SUITE 100 DUBLIN, OH 43017	engineering services	Invoice Cost	107	14,849
			560	23,790
			592	154
				38,793
VAUGHN INDUSTRIES 1201 E. FINDLAY STREET CAREY, OH 43316	substation electrical work services	Invoice Cost	107	4,035,171
			108	158,391
			571	800
				4,194,363
WB-KOESTER CONSTRUCTION LLC 14601 HIGHWAY 41 NORTH, SUITE 200 EVANSVILLE, IN 47725	fly ash landfill construction services	Invoice Cost	107	1,029,058
			108	29,004
			186	254,215
			501	12,557
				1,324,834
WEIR VALVES & CONTROLS USE INC 29 OLD RIGHT ROAD IPSWICH, MA 01938	valve repair services	Invoice Cost	512	91,744
				91,744
WESTINGHOUSE ELECTRIC CORP 4350 NORTHERN PIKE MONROEVILLE, PA 15146	nuclear support services	Invoice Cost	517	164,000
			530	993,483
				1,157,483
WHAYNE SUPPLY CO 1400 CECIL AVENUE LOUISVILLE, KY 40211	equipment repair services	Invoice Cost	107	59,236
			501	157,466
			512	337,739
			514	683
				555,124
WIGHTMAN & ASSOCIATES, INC 110 E. WAYNE STREET FORT WAYNE, IN 46801	topographic surveying services	Invoice Cost	107	238,568
				238,568
WILLIAMS CREEK MANAGEMENT CORP 4620 S. COUNTY ROAD 600 EAST PLAINFIELD, IN 46168	stream bank stabilization project services	Invoice Cost	571	40,950
				40,950
WISCONSIN ENERGY CONSERVATION 431 CHARMWAY DRIVE MADISON, WI 53719	business consulting services	Invoice Cost	908	2,703,018
				2,703,018

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Charges for Outside Professional & Other Consulting Services - Payments of $25,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
WORLEYPARSONS GROUP INC	engineering services	Invoice Cost	107	1,356,229
2675 MORGANTOWN ROAD				1,356,229
READING, PA 19607				
WRIGHT TREE SERVICE INC	tree trimming services	Invoice Cost	107	1,720,541
139 6TH STREET			108	70,398
DESMOINES, IA 50306			571	3,183,797
				4,974,737

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SUMMARY OF COSTS BILLED TO ASSOCIATED COMPANIES

1. In column (a) report the name of the associated company.
2. In column (b) describe the affiliation (percentage ownership, etc.).
3. In column (c) describe the nature of the goods and services provided (administrative and general expenses, dividends declared, etc.).
4. In columns (d) and (e) report the amount classified to operating income and the account(s) in which reported.

Line No.	Company (a)	Affiliation (b)	Description: Nature of Goods and Services (c)	Account Number (d)	Amount Classified to Operating Income (e)
1	Ohio Power Company	Subsidiaries of AEP	Coal & Urea Barging Costs		
2	Appalachian Power Co				
3	AEP Generating Company				
4	Kentucky Power				
5	Memco Consolidated				
6	Ohio Power - Cook Coal Terminal	Subsidiary of AEP	Boat Rental		
7	Cardinal Operating Co	Subsidiaries of AEP	Rail Car Rental		
8	Southwest Elec Power Co				
9	Ohio Power Company				
10	Public Service Co of OK				
11	Kentucky Power				
12	Appalachian Power Co				
13					
14					
15	AEP Generating Company	Subsidiary of AEP	Costs billed to operate jointly-owned Rockport facilities	408	521,686
16				456	(210,000)
17				500	2,554,357
18				501	171,088,413
19				502	1,409,370
20				505	1,463,147
21				506	1,272,530
22				507	68,283,024
23				510	1,878,612
24				511	777,762
25				512	10,717,238
26				513	3,306,401
27				514	904,270
28				556	723
29				557	(23,735)
30				920	92,248
31				921	139,301
32				922	0
33				923	869,634
34				924	141,196
35				925	(6,925)
36				926	1,964,687
37				930	97,328
38				931	885
39				935	97,053
40					
41					
42					
43	AEP Generating Company	Subsidiary of AEP	(1)	426	0
44				500	1,121,604
45				506	2,325,785
46				510	221,758
47				511	0
48				512	0
49				513	15,937
50				514	71,022
51				519	236
52				546	0
53				920	0
54				921	42,923
55				923	85
56				925	87
57					
58					
59					
60					
61					

(1) Misc transactions rendered at cost

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SUMMARY OF COSTS BILLED TO ASSOCIATED COMPANIES (Continued)

5. In columns (f) and (g) report the amount classified to non-operating income and the account(s) in which reported.
6. In columns (h) and (i) report the amount classified to the balance sheet and the account(s) in which reported.
7. In column (j) report the total.
8. In column (k) indicate the pricing method (cost, per contract terms, etc.)

Account Number (f)	Amount Classified to Non-operating Income (g)	Account Number (h)	Amount Classified to Balance Sheet (i)	Total (j)	Pricing Method (k)	Line No.
417	36,887,653				Alloc of barging	1
	27,455,375				costs based on	2
	15,459,416				deliveries of coal.	3
	121,876					4
	25,356,236			105,280,556		5
417	92,512			92,512	Fee - contract	6
		151	6,293		Alloc of actual	7
		151	2,662,290		usage of cars.	8
		151	170,029			9
		151	841,894			10
		151	0			11
		151	0	3,680,505		12
						13
						14
421	(78)	107	20,256,074		Cost	15
426	257,058	108	2,315,722			16
431	37,878	151	(12,721,690)			17
		152	(202,688)			18
		154	402,533			19
		186	175,607			20
		242	0			21
		253	5,570,952			22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
				283,430,576		42
		107	147,110		Cost	43
		108	9,444			44
		151	(27,464)			45
		154	784			46
		152	5			47
		163	125,260			48
						49
						50
						51
						52
						53
						54
						55
						56
						57
						58
				4,054,575		59
						60
						61

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SUMMARY OF COSTS BILLED TO ASSOCIATED COMPANIES (Continued)

1. In column (a) report the name of the associated company.
2. In column (b) describe the affiliation (percentage ownership, etc.).
3. In column (c) describe the nature of the goods and services provided (administrative and general expenses, dividends declared, etc.).
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Line No.	Company (a)	Affiliation (b)	Description: Nature of Goods and Services (c)	Account Number (d)	Amount Classified to Operating Income (e)
1	AEP Pro Serv, Inc.	Subsidiary of AEP	(1)		
2				923	6,822
3	AEP Service Corporation	Parent Company	(1)	920	1,571
4		Service Corp.		921	0
5				923	63
6				935	6,594
7					
8					
9	AEP T&D Services, LLC	Subsidiary of AEP	(1)	566,930	3,365
10					
11	AEP Texas Central Co	Subsidiary of AEP	(1)	560	1,662
12				563	173
14				566	118
15				570	44
16				580	964
17				583	2
18				586	(4,076)
19				588	278
20				592	1,775
21				593	93
22				594	4
23				595	6
24				903	679
25				920	608
26				923	350
27				935	537
28	AEP Texas North Co	Subsidiary of AEP	(1)	500	425
29				506	4,162
30				560	1,677
31				563	175
32				566	119
33				570	785
34				580	229
35				586	170
36				588	67
37				592	1,123
38				903	473
39				923	132
40				935	53
41					
42					
43					
44	American Electric Power Co	Parent Company	(1)	920-621	0
45				930-935	0
46	Appalachian Power Co	Subsidiary of AEP	(1)	500	108
47				506	4,542
48				510	28,639
49				512	520
50				513	525
51				514	4,307
52				539	522
53				544	2,042
54				563	214
55				566	17,530
56				567	46
57				570	252
58				571	1,001
59				580	1,184
60					

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SUMMARY OF COSTS BILLED TO ASSOCIATED COMPANIES (Continued)

5. In columns (f) and (g) report the amount classified to non-operating income and the account(s) in which reported.
6. In columns (h) and (i) report the amount classified to the balance sheet and the account(s) in which reported.
7. In column (j) report the total.
8. In column (k) indicate the pricing method (cost, per contract terms, etc.)

Account Number (f)	Amount Classified to Non-operating Income (g)	Account Number (h)	Amount Classified to Balance Sheet (i)	Total (j)	Pricing Method (k)	Line No.
				6,822	Cost	1
						2
419	0	107	121,841		Cost	3
		184	0			4
		186	0			5
						6
						7
				130,068		8
		163	8		Cost	9
				3,373		10
426	0	107	1,616		Cost	11
		108	4			12
		154	38,236			14
		163	854			15
		188	0			16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
				43,926		27
426	0	152	2		Cost	28
		154	234			29
		163	0			30
		184	0			31
		188	0			32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
				9,826		43
426	7,455				Cost	44
				7,455		45
426	0	107	4,254		Cost	46
456	(9,908)	108	(612)			47
		143	0			48
		152	23			49
		154	670,191			50
		184	1,777			51
						52
						53
						54
						55
						56
						57
						58
						59
						60

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SUMMARY OF COSTS BILLED TO ASSOCIATED COMPANIES

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Line No.	Company (a)	Affiliation (b)	Description: Nature of Goods and Services (c)	Account Number (d)	Amount Classified to Operating Income (e)
1	Appalachian Power Co (cont)			583	46
2				586	112
3				587	(37)
4				588	343
5				593	1,048
6				594	6
7				595	(92)
8				597	390
9				903	63
10				921	4
11				923	1,002
12				925	506
13				935	1,790
14					
15					
16	Blackhawk Coal Co	Subsidiary of AEP	(1)		
17	Cardinal Operating Co	Subsidiary of AEP	(1)	500	0
18				506	4,162
19				510	443
20				512	3
21				571	22
22					
23					
24					
25					
26	Wheeling Power Co (cont)	Subsidiary of AEP	(1)	560	74
27				563	8
28				566	632
29				580	51
30				588	15
31				597	27
32				921	33
33				923	15
34				935	5
35					
36					
37					
38					
39					
40					
41					
42	AEP Trancos	Subsidiary of AEP	(1)	56x	146
43				92x	8,697
44	Conesville Coal Prep Co	Subsidiary of AEP	(1)	935	1
45					
46					
47					
48	Ohio Power - Cook Coal Terminal	Subsidiary of AEP	(1)	501	7,435
49				923	1
50				935	3
51					
52					
61					

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SUMMARY OF COSTS BILLED TO ASSOCIATED COMPANIES (Continued)

5. In columns (f) and (g) report the amount classified to non-operating income and the account(s) in which reported.
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Account Number (f)	Amount Classified to Non-operating Income (g)	Account Number (h)	Amount Classified to Balance Sheet (i)	Total (j)	Pricing Method (k)	Line No.
				732,336		15
426	3,323	228	4,739	8,062		16
		107	7		Cost	17
		152	15			18
				4,652		25
		107	777			26
				1,636		41
426	1,489	107	10,667		Cost	42
				20,999		43
					Cost	44
				1		47
					Cost	48
				7,439		61

Name of Respondent	This Report Is:	Date of Report	Year of Report
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SUMMARY OF COSTS BILLED TO ASSOCIATED COMPANIES

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Line No.	Company (a)	Affiliation (b)	Description: Nature of Goods and Services (c)	Account Number (d)	Amount Classified to Operating Income (e)
1	CSW Energy	Subsidiary of AEP	(1)	923	15
2				935	5
3	Kentucky Power Co	Subsidiary of AEP	(1)	505	510
4				506	4,545
5				510	267
6				560	500
7				563	52
8				566	4,293
9				571	2
10				580	214
11				588	63
12				592	710
13				597	89
14				920	2,964
15				921	186
16				923	168
17				925	48
18				935	49
19					
20					
21					
22					
23	Kingsport Power Co	Subsidiary of AEP	(1)	560	21
24				563	2
25				566	543
26				580	59
27				588	17
28				597	16
29				923	12
30				935	6
31					
32					
33					
34					
35					
36	Memco Consolidated	Subsidiary of AEP	(1)	580	33,157
37				920-921	591,752
38	Ohio Power Co	Subsidiary of AEP	(1)	456	(77,790)
39				500	176,236
40				506	8,485
41				510	14,121
42				513	165,609
43				545-560	(7,122)
44				562	125
45				563	11,990
46				566	26,902
47				570	2,232
48				571	195,851
49				580	10,426
50				583	1,027
51				586	2,277
52				587	77
53				588	2,455
54				592	1,323
55				593	203,470
56				594	2,084
57				595	42,247
58				596	23
59				597	573
60				598	350

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SUMMARY OF COSTS BILLED TO ASSOCIATED COMPANIES (Continued)

5. In columns (f) and (g) report the amount classified to non-operating income and the account(s) in which reported.
6. In columns (h) and (i) report the amount classified to the balance sheet and the account(s) in which reported.
7. In column (j) report the total.
8. In column (k) indicate the pricing method (cost, per contract terms, etc.)

Account Number (f)	Amount Classified to Non-operating Income (g)	Account Number (h)	Amount Classified to Balance Sheet (i)	Total (j)	Pricing Method (k)	Line No.
					Cost	1
				20		2
		107	28,311		Cost	3
		108	203			4
		154	10,833			5
		152	5			6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
				54,011		22
		107	2,396		Cost	23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
				3,073		35
417	143,975				Cost	36
				768,884		37
417	2	107	407,787		Cost	38
		108	39,956			39
		154	1,573,934			40
		152	30			41
		163	25,206			42
		184	4,151			43
		185	107			44
		186	(320,643)			45
		236	(34)			46
						47
						48
						49
						50
						51
						52
						53
						54
						55
						56
						57
						58
						59
						60

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, 2011

SUMMARY OF COSTS BILLED TO ASSOCIATED COMPANIES

1. In column (a) report the name of the associated company.
2. In column (b) describe the affiliation (percentage ownership, etc.).
3. In column (c) describe the nature of the goods and services provided (administrative and general expenses, dividends declared, etc.).
4. In columns (d) and (e) report the amount classified to operating income and the account(s) in which reported.

Line No.	Company (a)	Affiliation (b)	Description: Nature of Goods and Services (c)	Account Number (d)	Amount Classified to Operating Income (e)
1	Ohio Power Co (cont)			903	455
2				920	10,089
3				921	911
4				922	(8,753)
5				923	1,479
6				925	942
7				930	4,992
8				935	59,684
9					
10					
11					
12					
13					
14	Public Service Co of OK	Subsidiary of AEP	(1)	500	183
15				506	4,162
16				560	1,370
17				563	144
18				566	98
19				580	657
20				586	366
21				588	191
22				593	90
23				903	9,656
24				923	372
25				935	139
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38	Southwestern Elec Pwr Co	Subsidiary of AEP	(1)	506	4,364
39				512	(288)
40				530	(91)
41				560	1,538
42				563	163
43				566	111
44				570	80
45				580	628
46				584	(34)
47				586	(26,845)
48				588	367
49				592	596
50				593	327
51				921	245
52				923	448
53				935	141
54					
55					
56					
57					
58					
59					
60	**Totals**				**272,750,463**

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, 2011

SUMMARY OF COSTS BILLED TO ASSOCIATED COMPANIES (Continued)

5. In columns (f) and (g) report the amount classified to non-operating income and the account(s) in which reported.
6. In columns (h) and (i) report the amount classified to the balance sheet and the account(s) in which reported.
7. In column (j) report the total.
8. In column (k) indicate the pricing method (cost, per contract terms, etc.)

Account Number (f)	Amount Classified to Non-operating Income (g)	Account Number (h)	Amount Classified to Balance Sheet (i)	Total (j)	Pricing Method (k)	Line No.
				2,583,266		1
417	(2)	107	834		Cost	14
456	(400)	108	20			15
		154	63,521			16
		152	11			17
		184	2			18
		186	(57,070)			19
				24,344		37
417	(1)	107	2,848		Cost	38
		108	(155,007)			39
		154	39,288			40
		152	13			41
		184	0			42
		186	(475,669)			43
				(606,775)		59
Totals	**105,813,859**		**21,777,821**	**400,342,143**		60

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, 2011

SUMMARY OF COSTS BILLED FROM ASSOCIATED COMPANIES

1. In column (a) report the name of the associated company.
2. In column (b) describe the affiliation (percentage ownership, etc.).
3. In column (c) describe the nature of the goods and services provided (administrative and general expenses, dividends declared, etc.).
4. In columns (d) and (e) report the amount classified to operating income and the account(s) in which reported.

Line No.	Company (a)	Affiliation (b)	Description: Nature of Goods and Services (c)	Account Number (d)	Amount Classified to Operating Income (e)
1	Memco Consolidated	Subsidiary of AEP	Coal Barging		
2	Memco Consolidated	Subsidiary of AEP	River Trans G&A		
3	Appalachian Power Co	Subsidiary of AEP	Lakin Electric Billing		
4	AEP Transportation	Subsidiaries of AEP	Rail Car Usage		
5	Ohio Power Co				
6	Public Service Co of OK				
7	Southwest Elec Power Co				
8	Appalachian Power Co				
9	AEP Generating Company	Subsidiary of AEP	Purchased Power	555	228,739,225
10	AEP Service Corporation			555	124,598,280
11	Public Service Co of OK			555	19,875
12	Southwest Elec Power Co			555	126,706
13					
14	AEP Generating Company	Subsidiary of AEP	(1)	253	0
15				506-507, 930	154,822
16	AEP Texas Central Co	Subsidiary of AEP	(1)	512	1,142
17				560	3,101
18				566	228
19				570	354
20				571	31,144
21				580	2,094
22				583	12
23				586	256
24				588	20,121
25				593	406
26				594	(2)
27				903	0
28				935	787
29					
30					
32	AEP Texas North Co	Subsidiary of AEP	(1)	544	1,085
33				560	1,417
34				566	228
35				570	135
36				583	(1)
37				586	(5)
38				588	4,903
39				592	1
40				920	0
41				921	0
42				923	59
43				935	267
44	American Electric Power Co	Parent Co	(1)		
45					
46					
47	Appalachian Power Co	Subsidiary of AEP	(1)	426,456	(257,631)
48				500	2,395
49				502	80
50				506	1,266
51				510	64,089
52				512	2,120
53				513	310
54				539	601
55				543 - 545	789
56				560	463
57				566	177
58				570	5,321
59				571	(360,306)
60				580	10,576

(1) Misc transactions rendered at cost

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, 2011

SUMMARY OF COSTS BILLED FROM ASSOCIATED COMPANIES (Continued)

5. In columns (f) and (g) report the amount classified to non-operating income and the account(s) in which reported.
6. In columns (h) and (i) report the amount classified to the balance sheet and the account(s) in which reported.
7. In column (j) report the total.
8. In column (k) indicate the pricing method (cost, per contract terms, etc.)

Account Number (f)	Amount Classified to Non-operating Income (g)	Account Number (h)	Amount Classified to Balance Sheet (i)	Total (j)	Pricing Method (k)	Line No.
417	17,923,537			17,923,537	Cost	1
417	6,128,666			6,128,666	Cost	2
417	52,222			52,222	Cost	3
		151	0		Alloc of actual	4
		151	1,190,167		expense	5
		151	80,262			6
		151	787,169			7
		151	91,441	2,149,040		8
					The AEP System	9
					operates all gen	10
					facilities as agent	11
						12
				353,484,086		13
		154	10,024		Cost	14
		143	(17,340)	147,506		15
		107	134		Cost	16
		108	13			17
		154	36,448			18
		163	49			19
		184	100			20
		188	3,114			21
						22
						23
						24
						25
						26
						27
						28
						29
				99,502		30
		107	179		Cost	32
		108	(1)			33
		154	56,123			34
		163	0			35
		184	33			36
		188	163			37
						38
						39
						40
						41
						42
				64,585		43
		236	162		Cost	44
						45
				162		46
		107	120,303		Cost	47
		108	58			48
		143	1,785			49
		152	890			50
		154	792,019			51
		163	24,736			52
		183	18			53
		186	(1,839,360)			54
		188	350			55
		232	0			56
						57
						58
						59
						60

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, 2011

SUMMARY OF COSTS BILLED FROM ASSOCIATED COMPANIES

1. In column (a) report the name of the associated company.
2. In column (b) describe the affiliation (percentage ownership, etc.).
3. In column (c) describe the nature of the goods and services provided (administrative and general expenses, dividends declared, etc.).
4. In columns (d) and (e) report the amount classified to operating income and the account(s) in which reported.

Line No.	Company (a)	Affiliation (b)	Description: Nature of Goods and Services (c)	Account Number (d)	Amount Classified to Operating Income (e)
1	Appalachian Power Co (cont)			586	2,451
2				587	1,875
3				588	1,219
4				592	12,482
5				593	1,191
6				594	75
7				595	0
8				596	23
9				597	0
10				598	306
11				903	1,596
12				920	5,872
13				921	2,288
14				922	(311,269)
15				925	35,702
16				926	181
17				930	(5)
18				935	23,392
19					
20					
21	Cardinal Operating Co	Subsidiary of AEP	(1)		
22					
23					
24					
25	AEP Service Corporation	Subsidiary of AEP	(1)	50x	6,051,595
26				51x	3,714,009
27				52x	1,118,552
28				53x	1,917,251
29				54x	141,109
30				55x	8,306,530
31				56x	4,980,778
32				57x	684,127
33				58x	3,183,484
34				59x	257,891
35				90x	14,701,142
36				91x	66
37				92x	44,300,289
38				93x	1,048,081
39	Central Machine Shop and		(1)	50x	19,835
40	Central Machine Facility			51x	1,465,636
41				52x	16,819
42				53x	323,438
43				54x	3,252
44					
45	AEP Energy Services				
46					
47					
48					
49					
50					
51					
52	Conesville Coal	Subsidiary of AEP	(1)		
53	Kentucky Power Co	Subsidiary of AEP	(1)	500	17
54				509	188,802
55				570	359
56				583	39
57				586	640
58				587	14
59				592	1,621

(1) Misc transactions rendered at cost

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, 2011

SUMMARY OF COSTS BILLED FROM ASSOCIATED COMPANIES (Continued)

5. In columns (f) and (g) report the amount classified to non-operating income and the account(s) in which reported.
6. In columns (h) and (i) report the amount classified to the balance sheet and the account(s) in which reported.
7. In column (j) report the total.
8. In column (k) indicate the pricing method (cost, per contract terms, etc.)

Account Number (f)	Amount Classified to Non-operating Income (g)	Account Number (h)	Amount Classified to Balance Sheet (i)	Total (j)	Pricing Method (k)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
				(1,651,573)		20
		107	797		Cost	21
				797		22
						23
						24
417	1,213,121	107	24,764,282			25
421	(177)	108	1,129,623			26
426	1,380,522	121	17,322			27
		151	(211)			28
		152	2,427,154			29
		163	1,336,998			30
		182	485			31
		183	687,196			32
		184	94,456			33
		186	181,051			34
		188	3,271,363			35
		242	185			36
				126,908,373	Cost	37
						38
		107	303,179			39
		108	34,494			40
		163	3,843			41
				2,170,495	Cost	42
						43
						44
		107	272	272		45
						46
						47
						48
						49
						50
						51
		107	10	10	Cost	52
		107	4,342		Cost	53
		108	48			54
		154	155,261			55
		163	0			56
		186	(32,196)			57
						58
						59

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, 2011

SUMMARY OF COSTS BILLED FROM ASSOCIATED COMPANIES

1. In column (a) report the name of the associated company.
2. In column (b) describe the affiliation (percentage ownership, etc.).
3. In column (c) describe the nature of the goods and services provided (administrative and general expenses, dividends declared, etc.).
4. In columns (d) and (e) report the amount classified to operating income and the account(s) in which reported.

Line No.	Company (a)	Affiliation (b)	Description: Nature of Goods and Services (c)	Account Number (d)	Amount Classified to Operating Income (e)
1	Kentucky Power Co (cont)			593	10,419
2				594	72
3				920	3,532
4				921	156
5				922	(4,442)
6				923	2,981
7				930	836
8				935	4,502
9					
10	Kingsport Power Co	Subsidiary of AEP	(1)	512-593	595
11	Ohio Power Co	Subsidiary of AEP	(1)	426-456	(8,725)
12				500	5,556
13				506	3,184
14				510	12,826
15				511-513	3,819
16				539	2,881
17				544-561	2,569
18				563	5,195
19				566	4,539
20				567	529
21				570	5,799
22				571	913
23				580	40,866
24				583	784
25				584-585	56
26				586	100,861
27				588	53,426
28				591	2,041
29				592	23,962
30				593	232,984
31				594	1,045
32				595	4,357
33				596	82
34				597	1,155
35				598	4,690
36				903-907	2,583
37				920	5,240
38				921	1,039
39				922	(21,623)
40				923	286,176
41				925	4,445
42				930	1,155,577
43				935	27,211
44					
45	Public Service Co of OK	Subsidiary of AEP	(1)	506	1,214
46				510	0
47				512	89,686
48				561	5,412
49				566	342
50				571	17,266
51				580	10,632
52				583	3
53				586	64
54				587	38
55				588	26,831
56				593	(44)
57				596	(8)
58				901	191
59				903	283
60				920-935	(154,674)

(1) Misc transactions rendered at cost

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, 2011

SUMMARY OF COSTS BILLED FROM ASSOCIATED COMPANIES (Continued)

5. In columns (f) and (g) report the amount classified to non-operating income and the account(s) in which reported.
6. In columns (h) and (i) report the amount classified to the balance sheet and the account(s) in which reported.
7. In column (j) report the total.
8. In column (k) indicate the pricing method (cost, per contract terms, etc.)

Account Number (f)	Amount Classified to Non-operating Income (g)	Account Number (h)	Amount Classified to Balance Sheet (i)	Total (j)	Pricing Method (k)	Line No.
				337,002		1
		107	0	595	Cost	10
		107	250,593		Cost	11
		108	46,828			12
		124	2,398			13
		154	1,458,985			14
		152	20			15
		163	17,923			16
		183	63,269			17
		184	393			18
		186	(122,706)			19
		188	1,396			20
		253	(874,437)			21
				2,810,703		44
		107	441		Cost	45
		108	(15)			46
		154	21,924			47
		143	7,012			48
		163	28			49
		184	18			50
		186	(968,030)			51

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, 2011

SUMMARY OF COSTS BILLED FROM ASSOCIATED COMPANIES

1. In column (a) report the name of the associated company.
2. In column (b) describe the affiliation (percentage ownership, etc.).
3. In column (c) describe the nature of the goods and services provided (administrative and general expenses, dividends declared, etc.).
4. In columns (d) and (e) report the amount classified to operating income and the account(s) in which reported.

Line No.	Company (a)	Affiliation (b)	Description: Nature of Goods and Services (c)	Account Number (d)	Amount Classified to Operating Income (e)
1	Public Service Co of OK(cont)				
2					
3					
4					
5					
6	Southwestern Elec Pwr Co.	Subsidiary of AEP	(1)	500	2,327
7				506	3,277
8				512	1,843
9				560	138
10				561	4,168
11				571	53,131
12				580	168
13				586	2,676
14				588	25,619
15				591	249
16				592	1,128
17				593	1,318
18				594	10
19				903	188
20				907	54
21				920	16,520
22				921	344
23				930	1,430
24				935	8,961
25					
26					
27					
28					
29					
30	Wheeling Power Co	Subsidiary of AEP	(1)	583	3
31				593	47
32				903	47
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49					
50					
51					
52					
53					
54					
55					
56					
57					
58					
59					
60	**TOTALS**				**447,485,224**

(1) Misc transactions rendered at cost

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, 2011

SUMMARY OF COSTS BILLED FROM ASSOCIATED COMPANIES (Continued)

5. In columns (f) and (g) report the amount classified to non-operating income and the account(s) in which reported.
6. In columns (h) and (i) report the amount classified to the balance sheet and the account(s) in which reported.
7. In column (j) report the total.
8. In column (k) indicate the pricing method (cost, per contract terms, etc.)

Account Number (f)	Amount Classified to Non-operating Income (g)	Account Number (h)	Amount Classified to Balance Sheet (i)	Total (j)	Pricing Method (k)	Line No.
				(941,384)		1
454	0	107	18,227		Cost	2
		108	19			3
		154	60,413			4
		152	17			5
		253	(243,780)			6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
				(41,553)		29
		107	6		Cost	30
		108	1			31
		154	6,049			32
						33
						34
				6,153		35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46
						47
						48
						49
						50
						51
						52
						53
						54
						55
						56
						57
						58
						59
	26,697,892		**35,465,978**	**509,649,093**		60

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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)	18,638,372
3	Steam	12,115,589	23	Requirements Sales for Resale (See instruction 4, page 311.)	4,902,173
4	Nuclear	17,358,237	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	17,056,685
5	Hydro-Conventional	105,166	25	Energy Furnished Without Charge	50
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other		27	Total Energy Losses	2,081,541
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	42,678,821
9	Net Generation (Enter Total of lines 3 through 8)	29,578,992			
10	Purchases	13,099,829			
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)	42,678,821			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

MONTHLY PEAKS AND OUTPUT

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

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	3,991,923	1,764,097	3,764	31	2100
30	February	3,109,414	1,190,092	3,783	10	0800
31	March	3,103,562	803,158	3,457	15	0700
32	April	2,999,259	1,313,554	3,207	19	1200
33	May	2,980,745	1,013,113	3,931	31	1400
34	June	3,908,867	1,796,050	4,417	7	1500
35	July	4,319,517	1,845,340	4,837	21	1400
36	August	4,369,659	2,007,823	4,517	2	1600
37	September	3,288,610	1,284,205	4,441	2	1600
38	October	3,112,257	1,175,025	3,249	20	1200
39	November	3,636,505	1,671,922	3,619	29	1800
40	December	3,858,503	1,728,739	3,528	12	0800
41	TOTAL	42,678,821	17,593,118			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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)	669	674
7	Plant Hours Connected to Load	5128	8206
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	3183245000	5013348000
13	Cost of Plant: Land and Land Rights	6508470	68095
14	Structures and Improvements	90941645	6097159
15	Equipment Costs	561935993	88675599
16	Asset Retirement Costs	1333993	1310640
17	Total Cost	660720101	96151493
18	Cost per KW of Installed Capacity (line 17/5) Including	1001.0911	147.9254
19	Production Expenses: Oper, Supv, & Engr	1679434	1683982
20	Fuel	69082904	111490651
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	881726	2197247
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	758416	704716
26	Misc Steam (or Nuclear) Power Expenses	-3387661	-3549059
27	Rents	3208	70150460
28	Allowances	6802445	6802445
29	Maintenance Supervision and Engineering	1017269	947516
30	Maintenance of Structures	607622	169374
31	Maintenance of Boiler (or reactor) Plant	8380438	2128972
32	Maintenance of Electric Plant	2699642	607155
33	Maintenance of Misc Steam (or Nuclear) Plant	599377	304584
34	Total Production Expenses	89124820	193638043
35	Expenses per Net KWh	0.0280	0.0386
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 2011/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
1333	2666	971	6
8206	8206	6600	7
0	0	0	8
1310	2620	995	9
1308	2615	985	10
0	231	137	11
8196593000	16391329000	3918996000	12
6576565	13123804	4099388	13
97038804	195925083	53549709	14
650611592	1303269531	577734748	15
2644633	5220652	23223153	16
756871594	1517539070	658606998	17
577.7646	579.2134	661.9166	18
3363415	6033911	3053978	19
180573555	361720987	117539290	20
0	0	0	21
3078973	7294169	3745847	22
0	0	0	23
0	0	0	24
1463132	2926279	210641	25
-6936719	-4712846	-3182167	26
70153668	138439331	3464	27
13604891	13604891	7031101	28
1964785	3852359	1833890	29
776996	1554014	2232042	30
10509409	21222260	12828432	31
3306798	6613826	4603125	32
903960	1807950	1756363	33
282762863	560357131	151656006	34
0.0345	0.0342	0.0387	35

Coal	Oil		Coal	Oil		Coal	Oil		
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
4557184	26567	0	9113509	53127	0	2027752	17327	0	38
8818	137531	0	8818	137531	0	10185	136997	0	39
38.980	130.950	0.000	38.980	130.950	0.000	55.310	129.990	0.000	40
38.970	111.680	0.000	39.040	111.680	0.000	57.050	119.920	0.000	41
2.210	19.335	0.000	2.210	19.340	0.000	2.800	20.840	0.000	42
0.022	0.000	0.000	0.022	0.000	0.000	0.295	0.000	0.000	43
9825.000	0.000	0.000	9824.000	0.000	0.000	10565.000	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 2011/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)	2223	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	1055	0
12	Net Generation, Exclusive of Plant Use - KWh	17358237000	0
13	Cost of Plant: Land and Land Rights	1879588	0
14	Structures and Improvements	345234194	0
15	Equipment Costs	1940821213	0
16	Asset Retirement Costs	151397582	0
17	Total Cost	2439332577	0
18	Cost per KW of Installed Capacity (line 17/5) Including	1067.5416	0
19	Production Expenses: Oper, Supv, & Engr	19466001	0
20	Fuel	159326773	0
21	Coolants and Water (Nuclear Plants Only)	6135422	0
22	Steam Expenses	10775472	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	2536554	0
26	Misc Steam (or Nuclear) Power Expenses	76854469	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	11924099	0
30	Maintenance of Structures	3192035	0
31	Maintenance of Boiler (or reactor) Plant	74650379	0
32	Maintenance of Electric Plant	22700759	0
33	Maintenance of Misc Steam (or Nuclear) Plant	21400374	0
34	Total Production Expenses	408962337	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	0.848	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.009	0.000
44	Average BTU per KWh Net Generation	10819.000	0.000

		0	0	0	0	0
		0	0	0	0	0
		0.000	0.000	0.000	0.000	0.000
		0.000	0.000	0.000	0.000	0.000
		0.000	0.000	0.000	0.000	0.000
		0.000	0.000	0.000	0.000	0.000
		0.000	0.000	0.000	0.000	0.000

Schedule Page: 402 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.

Schedule Page: 402 Line No.: 26 Column: b

Misc Steam Power Expenses show as credits for Rockport Unit 1, Rockport Unit 2, and Tanners Creek due to accounting entries. Per IURC Cause No. 38702 FAC 62-S1, I&M credited $13.5M to customers through the fuel adjustment clause for the Cook Plant Unit 1 fire outage replacement power costs. Reversal of a $2.5M accrual related to potential customer refunds for the incremental replacement power costs incurred during Cook Unit 1 fire outage. This was split 28.32% to Rockport Unit 1, 28.32% to Rockport Unit 2 and 43.36% to Tanners Creek.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	8.0	36,415	14,716,274
3	Buchanan (Project #2551)	1919	4.10	3.0	14,782	7,317,209
4	Constantine (Project #10661)	1921	1.20	2.0	6,040	2,708,198
5	Elkhart (Project #2651)	1913	3.44	4.0	14,233	6,351,593
6	Mottville (Project #401)	1923	1.68	2.0	6,099	3,396,364
7	Twin Branch (Project #2579)	1904	4.80	5.0	27,597	11,726,753
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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
2,043,927	375,851		244,476			2
1,784,685	245,143		898,761			3
2,256,832	91,749		135,197			4
1,846,393	220,953		250,229			5
2,021,645	130,925		226,379			6
2,443,074	277,133		171,487			7
						8
						9
						10
						11
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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, 2011

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	NONE				
9					
10					
11					
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						

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2011

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 (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2011

STEAM ELECTRIC GENERATING PLANTS (cont'd)

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

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

Turbine-Generators

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

	TURBINES				GENERATORS							
	Include both ratings for boiler and turbine-generator of dual-rated installations				NAME PLATE Rating in Kw		Hydrogen Pressure *(Designate air cooled generators)*					
Year Installed	Max. Rating Mega-Watt	Type (Indicate tandem-compound (TC); cross compound (CC) single casing (SC); topping unit (T); and non-condensing (NC) Show back pressures)	Steam Pressure at Throttle 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.	Power Factor	Voltage (in MV) (If other than 3 phase, 60 cycle indicate other characteristic)	Plant Capacity Maximum Generator Name Plate Rating (Should agree with column (n))	Line No.
(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	
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 2011/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	203.00		1
3	6136 DUMONT	WILTON CENTER	765.00	765.00	STEEL	63.00		1
4	6141 DUMONT	MARYSVILLE	765.00	765.00	STEEL	104.00		1
5	6215 D.C. COOK	DUMONT	765.00	765.00	STEEL	20.00		1
6	6223 ROCKPORT	JEFFERSON	765.00	765.00	STEEL	111.00		1
7	6224 ROCKPORT	SULLIVAN	765.00	765.00	STEEL	97.00		1
8	6226 JEFFERSON	WEST	765.00	765.00				
9	6236 HANGING ROCK	JEFFERSON	765.00	765.00	STEEL	1.00		1
10	0675 TANNERS CREEK	SORENSON	345.00	345.00	STEEL	136.00		2
11	0676 SORENSON	EAST LIMA	345.00	345.00	STEEL	30.00		1
12	0677 BREED	DEQUINE EAST	345.00	345.00	STEEL	188.19		2
13	0678 DEQUINE	OLIVE	345.00	345.00	STEEL	0.45		
14	0679 SORENSON	OLIVE	345.00	345.00	STEEL	78.00		2
15	0680 OLIVE	GOODINGS GROVE	345.00	345.00	STEEL	41.00		2
16	0683 DESOTO	JCT TOWER (MAR. CO)	345.00	345.00	STEEL	53.00	6.00	1
17	0684 TANNERS CREEK	JUNCTION TOWER	345.00	345.00	ST & ALUM	80.00		1
18	0685 HANNA	JUNCTION TOWER	345.00	345.00				
19	0687 TANNERS CREEK	MIAMI FORT	345.00	345.00	STEEL			2
20	0688 EUGENE	SIDNEY	345.00	345.00	WOOD POLE	2.00		1
21	0689 SORENSON-OLIVE	TWIN BRANCH	345.00	345.00	STEEL	11.00		2
22	0690 BREED	CIPSCO	345.00	345.00	STEEL	1.00		1
23	0691 BREED	PETERSBURG	345.00	345.00	STEEL	1.00		1
24	6118 ROBISON PARK	SORENSON-EAST LIMA	345.00	345.00	STEEL	23.00		1
25	6119 COOK	OLIVE	345.00	345.00	STEEL	4.00		2
26	6122 DUMONT	OLIVE	345.00	345.00	STEEL	15.00		2
27	6123 DUMONT	TWIN BRANCH	345.00	345.00	STEEL	17.00		2
28	6125 ROBISON PARK	EAST	345.00	345.00				
29	6133 DUMONT	BABCOCK	345.00	345.00	STEEL	9.00		1
30	6145 TWIN BRANCH	COOK-ROB PARK JCT	345.00	345.00	STEEL	6.00		2
31	6147 COOK	ROBISON PARK	345.00	345.00	STEEL	68.00		2
32	6148 JACKSON ROAD	SORENSON-OLIVE	345.00	345.00	STEEL	4.00		2
33	6213 COOK-ROB-PARK JCT	ARGENTA	345.00	345.00	STEEL	2.00		2
34	6237 JACKSON ROAD	WEST	345.00	345.00				
35	6240 TWIN BRANCH	SUBSTATION CORRIDOR	345.00	345.00				
36					TOTAL	3,937.64	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 2011/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	2,893,347	43,378,921	46,272,268					2
4-954 MCM	1,542,558	9,390,112	10,932,670					3
4-954 MCM	1,737,329	19,213,551	20,950,880					4
4-954 MCM	450,398	5,215,078	5,665,476					5
4-1351 MCM	6,286,757	87,903,402	94,190,159					6
4-1351 MCM	14,100,277	68,424,089	82,524,366					7
	761,721	9,497	771,218					8
4-1351 MCM	31,637	766,942	798,579					9
1275 MCM	1,455,976	11,618,198	13,074,174					10
1275 MCM	107,576	1,561,710	1,669,286					11
1414 MCM	1,304,053	12,057,984	13,362,037					12
2303 ACSR 54/37	481,571	11,551,539	12,033,110					13
1414 MCM	447,262	7,970,440	8,417,702					14
1414 MCM	429,643	4,660,850	5,090,493					15
2-954 MCM	513,937	3,976,476	4,490,413					16
2-954 MCM	457,068	6,585,480	7,042,548					17
	293,779	655,842	949,621					18
2-954 MCM		197,170	197,170					19
1414 MCM	10,088	602,243	612,331					20
1563 MCM	352,058	1,658,649	2,010,707					21
2-1024 MCM		314,122	314,122					22
2-954 MCM		188,845	188,845					23
1414 MCM	169,865	2,746,629	2,916,494					24
2-954 MCM	94,648	1,071,930	1,166,578					25
2-954 MCM	180,037	2,836,290	3,016,327					26
2-954 MCM	344,829	3,539,921	3,884,750					27
	173,109		173,109					28
2-954 MCM	163,248	1,187,728	1,350,976					29
2-954 MCM	187,405	1,212,899	1,400,304					30
2-954 MCM	1,604,481	14,423,542	16,028,023					31
2303 MCM	293,721	968,687	1,262,408					32
2-954 MCM	94,989	888,489	983,478					33
	48,061		48,061					34
	8,817		8,817					35
	59,425,678	560,412,735	619,838,413	355,042	8,167,896		8,522,938	36

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Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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.
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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	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	6256 BREED	SULLIVAN	345.00	345.00	STEEL	2.00		2
2	6259 COLLINGWOOD	SOUTH BUTLER	345.00	345.00	STEEL POLE	12.00		1
3	6127 EAST ELKHART TAP		138.00	138.00				
4	6232 GODMAN TAP		34.00	138.00				
5	0602 TWIN BRANCH	RIVERSIDE	138.00	138.00	STEEL	6.00		2
6	0603 TWIN BRANCH	SOUTH BEND	138.00	138.00	STEEL	5.00		1
7	0604 TWIN BRANCH	ROBISON PARK	138.00	138.00	STEEL	65.00		2
8	0605 SOUTH BEND	MICHIGAN CITY	138.00	138.00	STEEL			1
9	0606 ROBISON PARK	HAVILAND	138.00	138.00	STEEL	20.00		2
10	0607 ROBISON PARK	DEER CREEK	138.00	138.00	STEEL	60.00		2
11	0608 DEER CREEK	KOKOMO	138.00	138.00	STEEL	7.00		1
12	0609 CONCORD TAP		138.00	138.00	STEEL	4.00		2
13	0613 TWIN BRANCH	JACKSON ROAD	138.00	138.00	STEEL	8.00		2
14	0614 LINCOLN TAP		138.00	138.00	STEEL	4.00		2
15	0615 TWIN BRANCH	ROBISON PARK	138.00	138.00	STEEL	65.83		1
16	0616 DEER CREEK	DELAWARE	138.00	138.00	STEEL	24.50		2
17	0617 DELAWARE	MADISON	138.00	138.00	STEEL	19.00		2
18	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	STEEL TWR &	56.31		2
19	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	UNDERGROU	1.69		2
20	0725 DELAWARE	TRENTON	138.00	138.00	STEEL TWR &			
21	0619 MADISON	NEW CASTLE	138.00	138.00	STEEL	6.00	1.00	1
22	0620 TANNERS CREEK	MADISON	138.00	138.00	STEEL	82.00		2
23	0622 JACKSON ROAD	OLIVE	138.00	138.00	STEEL	17.00	1.00	1
24	0623 MADISON	PENDLETON	138.00	138.00	WOOD &	5.00		1
25	0624 DRAGOON TAP		138.00	138.00	STEEL	2.00		1
26	0625 TANNERS CREEK	COLLEGE CORNER	138.00	138.00	STEEL	40.00		2
27	0626 COLLEGE CORNER	RANDOLPH	138.00	138.00	WOOD	39.00		1
28	0627 RANDOLPH	JAY	138.00	138.00	WOOD	24.00		1
29	0628 MCKINLEY TAP		138.00	138.00	STEEL	1.00		2
30	0629 JAY	LINCOLN	138.00	138.00	WOOD &	49.00		1
31	0630 NEW CARLISLE	MAPLE	138.00	138.00	WOOD	1.00		1
32	6104 SORENSON	DEVILS HOLLOW	138.00	138.00	STEEL	3.00		2
33	0632 SORENSON	DEVILS HOLLOW	138.00	138.00	STEEL			
34	0634 DEER CREEK	MULLIN	138.00	138.00	WOOD	15.00		1
35	0635 PENDLETON	MULLIN	138.00	138.00	WOOD &	16.00		1
36					TOTAL	3,937.64	122.54	203

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TRANSMISSION LINE STATISTICS (Continued)

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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.
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1351.5 MCM		1,580,285	1,580,285					1
2-954 MCM	652,439	3,115,754	3,768,193					2
	10,276	297,119	307,395					3
	10,045	93,336	103,381					4
397.5 MCM	93,091	322,828	415,919					5
397.5 MCM	21,836	337,821	359,657					6
397.5 MCM	104,914	1,942,120	2,047,034					7
397.5 MCM	88,927	1,825,476	1,914,403					8
397.5 MCM	26,662	788,903	815,565					9
397.5 MCM	146,959	2,382,580	2,529,539					10
336.4 MCM	20,552	387,202	407,754					11
397.5 MCM	45,025	368,110	413,135					12
447 MCM	88,528	504,578	593,106					13
397.5 MCM	48,572	134,586	183,158					14
477 MCM	317,644	2,142,745	2,460,389					15
397.5 MCM	57,269	355,705	412,974					16
397.5 MCM	82,081	494,437	576,518					17
397.5 MCM	259,455	966,381	1,225,836					18
397.5 MCM								19
397.5 MCM		1,360,786	1,360,786					20
795 MCM	39,152	279,395	318,547					21
636 MCM	420,806	3,572,066	3,992,872					22
556.5 MCM	187,920	1,064,021	1,251,941					23
477 MCM	77,498	264,394	341,892					24
795 MCM	18,502	160,276	178,778					25
636 MCM	178,525	1,652,881	1,831,406					26
556.5 MCM	196,883	2,298,971	2,495,854					27
556.5 MCM	133,748	1,044,850	1,178,598					28
300 MCM CU	38,296	124,801	163,097					29
556.5 MCM	207,712	1,952,962	2,160,674					30
397.5 MCM	2,242	32,335	34,577					31
556.5 MCM	35,618	318,074	353,692					32
556.5 MCM	40,380	1,975,339	2,015,719					33
556.5 MCM	126,284	562,915	689,199					34
556.5 MCM	124,403	458,758	583,161					35
	59,425,678	560,412,735	619,838,413	355,042	8,167,896		8,522,938	36

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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	0636 DEER CREEK	FISHER BODY	138.00	138.00	STEEL	5.04		2
2	0637 TWIN BRANCH	CONCORD	138.00	138.00	STEEL	17.00	1.00	1
3	0638 GRANT	FISHER BODY	138.00	138.00	STEEL		1.00	1
4	0639 ROBISON PARK	AUBURN	138.00	138.00	WOOD &	15.00		1
5	0641 DESOTO	MEDFORD	138.00	138.00	STEEL	7.00		2
6	0642 OLIVE	HICKORY CREEK	138.00	138.00	STEEL	3.00	2.00	1
7	0645 COREY TAP		138.00	138.00	WOOD	4.00		1
8	0646 OLIVE	NEW CARLISLE	138.00	138.00	STEEL	2.00		1
9	0647 OLIVE	SOUTH BEND	138.00	138.00	STEEL	1.00	16.00	1
10	0648 MEDFORD TAP		138.00	138.00	STEEL	8.00		2
11	0714 EAST SIDE STA ENTR		138.00	138.00	UNDERGROU			1
12	0723 SPY RUN STATION		138.00	138.00	UNDERGROU			1
13	6101 WESTINGHOUSE TAP		138.00	138.00	STEEL	2.00		2
14	6102 MILAN TAP		138.00	138.00	STEEL	6.00		2
15	6103 MILAN	GOODRICH	138.00	138.00	STEEL	1.00		2
16	6105 DESOTO	JAY	138.00	138.00	WOOD &	13.00		1
17	6106 DESOTO	DEER CREEK-DELAWARE	138.00	138.00	STEEL	8.00		2
18	6107 DARDEN TAP		138.00	138.00	WOOD	1.00		1
19	6109 ROBISON PARK	RICHLAND	138.00	138.00	WOOD &	18.00		1
20	6110 WESTINGHOUSE	23RD STREET	138.00	138.00	STEEL			2
21	6111 KANKAKEE	WEST SIDE	138.00	138.00	WOOD POLE	2.00		1
22	6113 INDUSTRIAL PARK		138.00	138.00	STEEL	3.00		2
23	6114 OLIVE	MICHIGAN CITY	138.00	138.00	STEEL	2.00	1.00	1
24	6115 HUMMEL CREEK	VAN BUREN	138.00	138.00	STEEL	6.00		2
25	6130 HUMMEL CREEK	TOWER 70, GREENTOWN	138.00	138.00				
26	6116 SOUTH ELWOOD TAP		138.00	138.00	WOOD POLE	3.00		1
27	6117 PENDLETON	FALL CREEK	138.00	138.00	STEEL	10.00		2
28	6121 ROBISON PARK	LINCOLN	138.00	138.00	STEEL	8.00		1
29	6126 CONCORD	EAST ELKHART	138.00	138.00	STEEL	11.00		1
30	6129 GREENTOWN-GRANT	HUMMEL CREEK	138.00	138.00	STEEL	21.00		1
31	6131 INDUSTRIAL PARK	MC KINLEY	138.00	138.00	WOOD POLE	5.00		1
32	6132 CROSS STREET TAP	JUNCTION TOWER #88	138.00	138.00	WOOD POLE	4.00		1
33	6134 LINCOLN	ANTHONY	138.00	138.00	WOOD POLE	3.00		1
34	6135 WAYNEDALE TAP		138.00	138.00	STEEL			2
35	6138 JACKSON ROAD	SOUTH SIDE	138.00	138.00	WOOD POLE	2.00		1
36					TOTAL	3,937.64	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 2011/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)	
397.5 MCM	41,365	204,739	246,104					1
556.5 MCM	183,462	878,750	1,062,212					2
397.5 MCM	2,880	48,472	51,352					3
556.5 MCM	76,321	594,637	670,958					4
556.5 MCM	75,010	280,989	355,999					5
556.5 MCM	23,973	177,628	201,601					6
477 MCM	29,668	317,100	346,768					7
556.5 MCM	20,280	155,782	176,062					8
556.5 MCM	23,084	1,365,149	1,388,233					9
556.5 MCM	134,009	302,296	436,305					10
795 MCM		724,752	724,752					11
3.5IN OD		398,528	398,528					12
556.5 MCM	31,370	80,037	111,407					13
397.5 MCM	35,398	226,349	261,747					14
397.5 MCM	1,694	31,137	32,831					15
2-556.5 MCM	67,227	562,318	629,545					16
636 MCM	63,247	339,836	403,083					17
336.4 MCM	5,232	719,390	724,622					18
636 MCM	123,078	718,259	841,337					19
556.5 MCM	13,643	60,184	73,827					20
636 MCM	19,773	177,907	197,680					21
745 MCM	32,372	436,056	468,428					22
636 MCM	15,878	189,366	205,244					23
795 MCM	40,836	486,308	527,144					24
	44,222	584,596	628,818					25
556.5 MCM	5,090	678,826	683,916					26
795 MCM	176,360	969,302	1,145,662					27
795 MCM	677	983,213	983,890					28
795 MCM	179,506	986,412	1,165,918					29
795 MCM	180,124	1,321,738	1,501,862					30
795 MCM	75,257	326,046	401,303					31
795 MCM	262,613	192,719	455,332					32
795 MCM	90,524	634,914	725,438					33
795 MCM	22,040	71,621	93,661					34
795 MCM	1,633	627,504	629,137					35
	59,425,678	560,412,735	619,838,413	355,042	8,167,896		8,522,938	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 2011/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	6142 ALBION	KENDALLVILLE	138.00	138.00	WOOD POLE	10.00		1
2	6150 SOUTHSIDE	SOUTH BEND	138.00	138.00	WOOD &	6.07		1
3	6219 DELCO BATTERY TAP		138.00	138.00	STEEL POLE	1.00		2
4	6220 FALL CREEK	MADISON-NEW CASTLE	138.00	138.00	STEEL	1.00		2
5	6225 INDUSTRIAL PARK	SPY RUN	138.00	138.00	WOOD POLE	4.00		1
6	6266 WALLEN		138.00	138.00	STEEL POLE	0.22		1
7	6234 CABOT TAP/CR 4	EAST ELKHART	138.00	138.00	WOOD POLE	0.13		1
8	6238 SORENSON	MCKINLEYTOWER	138.00	138.00	STEEL	3.00		2
9	6241 KENDALLVILLE TAP	CITY OF AUBURN #5	138.00	138.00	WOOD H-FR	14.00		1
10	6242 AUBURN	CITY OF AUBURN #5	138.00	138.00	WOOD POLE	2.00		1
11	6245 LAPORTE JCT	LIQUID CARBONICS	138.00	138.00	WOOD POLE	5.00		1
12	6246 LAPORTE JCT	AIRCO	138.00	138.00	WOOD POLE	1.00		1
13	6248 ELCONA TAP	CONC-DUN-E-ELK	138.00	138.00	WOOD POLE	2.00		1
14	6249 ALLEN	LINCOLN	138.00	138.00	STEEL	5.00		2
15	6250 ALLEN	ADAMS/HILLCREST	138.00	138.00	STEEL	5.00		2
16	6251 OLIVE	EDISON	138.00	138.00	STEEL	1.00		2
17	6253 TRIER RD TAP		138.00	138.00	STEEL POLE			1
18	6258 KENZIE CREEK	TWIN BRANCH	138.00	138.00	STEEL			2
19	6260 WILMINGTON TAP		138.00	138.00	WOOD POLE	1.00	9.00	1
20	6229 DUNLAP NORTH TAP		34.00	138.00	WOOD POLE	2.00		2
21	6140 INDIANA-PURDUE		34.00	138.00	STEEL POLE			2
22	6217 HILLCREST	KINNERK	69.00	138.00	WOOD POLE	4.00		1
23	6252 KENDALLVILLE	BIXLER	138.00	138.00	WOOD POLE	2.00		1
24	6254 ALLEN/LINCOLN	ALLEN/HILLCREST	138.00	138.00				
25	6265 CONCORD	WOLF	138.00	138.00	WOOD POLE	0.56	0.54	1
26	INDALEX TAP/CR 4	EAST ELKHART	138.00	138.00	WOOD POLE	1.09		
27	6267 STUDEBAKER	WEST SIDE	138.00	138.00	WOOD POLE	1.41		1
28			138.00	138.00	STEEL	1.11		1
29	6270 JONES CREEK	HOGAN	138.00	138.00		5.62		
30	LINES<132 KV	SYSTEM	69.00		WOOD,	930.63	72.00	1
31								
32	STATE OF MICHIGAN							
33	6216 D.C. COOK	DUMONT	765.00	765.00	STEEL	16.00		1
34	6120 COOK	PALISADES	345.00	345.00	STEEL	42.00		2
35	6143 D.C. COOK	OLIVE-PALISADES	345.00	345.00	STEEL	5.00		2
36					TOTAL	3,937.64	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 2011/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	77,153	539,898	617,051					1
795 MCM	321,978	1,955,476	2,277,454					2
795 MCM AA	47,993	59,531	107,524					3
795 MCM	65,007	307,522	372,529					4
1033 MCM	91,134	603,198	694,332					5
1033.5 KCM		484,324	484,324					6
556.5 MCM		39,158	39,158					7
795 MCM	157,782	1,140,939	1,298,721					8
795 MCM	694,850	2,341,025	3,035,875					9
795 MCM	61,515	370,703	432,218					10
795 MCM	58,646	1,030,934	1,089,580					11
795 MCM	45,547	267,987	313,534					12
795 MCM	87,386	557,013	644,399					13
1033 MCM	23,500	1,658,390	1,681,890					14
1033 MCM		1,723,802	1,723,802					15
795 MCM	202,537	688,549	891,086					16
795 MCM		69,888	69,888					17
1033 MCM		136,604	136,604					18
2-954 MCM		1,365,463	1,365,463					19
795 MCM	10,443	304,289	314,732					20
1033 MCM	428	127,388	127,816					21
795 MCM	47,490	264,978	312,468					22
795 MCM	118,432	760,317	878,749					23
	385,522		385,522					24
336.4 ACSR KCM								25
		651,251	651,251					26
954 MCM	184,975	2,362,898	2,547,873					27
954 MCM								28
	2,100	5,707,002	5,709,102					29
VARIOUS	3,716,225	87,674,659	91,390,884					30
								31
								32
4-954 MCM	874,946	3,483,777	4,358,723					33
2-954 MCM	1,073,200	5,919,284	6,992,484					34
2-954 MCM	722,573	1,183,640	1,906,213					35
	59,425,678	560,412,735	619,838,413	355,042	8,167,896		8,522,938	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 2011/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	6144 TWIN BRANCH	COOK-ROB PARK JCT	345.00	345.00	STEEL			2
2	6151 COOK	OLIVE	345.00	345.00				
3	6152 COOK	ROBINSON PARK	345.00	345.00				
4	6146 D.C. COOK	ROBISON PARK	345.00	345.00	STEEL	37.00		2
5	6214 COOK-ROB PARK	ARGENTA	345.00	345.00	STEEL	29.00		2
6	6221 D.C. COOK	OLIVE-PALISADES	345.00	345.00	STEEL	5.00		2
7	6263 BARODA TAP		138.00	138.00				
8	0601 TWIN BRANCH	RIVERSIDE	138.00	138.00	STEEL	33.00		2
9	0610 AUTO SPECIALTIES		138.00	138.00				
10	0621 TWIN BRANCH - R	HICKORY CREEK	138.00	138.00	STEEL	5.00		2
11	0644 RIVERSIDE	HARTFORD	138.00	138.00	WOOD	16.33		1
12	0649 COREY TAP		138.00	138.00	WOOD	13.00		1
13	6108 RIVERSIDE	OLIVE-HICKORY CREEK	138.00	138.00	WOOD &	6.00		1
14	6124 BENTON HARBOR	RIVERSIDE-HARTFORD	138.00	138.00	STEEL	1.00		2
15	6137 EDGEWATER TAP		138.00	138.00	WOOD POLE	0.76		1
16	6139 BENTON HARBOR	TWIN BRANCH-R SIDE	138.00	138.00	STEEL	6.00		2
17	6149 HARTFORD	COREY	138.00	138.00	WOOD POLE	41.00		1
18	6218 MOTTVILLE TAP		138.00	138.00	WOOD POLE	1.00		1
19	6255 KENZIE CREEK	VALLEY	138.00	138.00	WOOD POLE	20.00		1
20	6257 KENZIE CREEK	T B/R'SIDE/HICK CR	138.00	138.00	STEEL			
21	6261 FLATBUSH TAP		138.00	138.00		1.00		1
22	6262 WEST ST TAP		138.00	138.00		1.00		2
23	6700 GM HYDRAMATIC		138.00	138.00	STEEL	2.00		2
24	6227 NICKERSON	TOWER #13A	138.00	138.00				
25	0643 OLIVE	HICKORY CREEK	138.00	138.00				
26	6268 SAUK TRAIL		138.00	138.00	STEEL	1.60		
27	LESS THAN 132 KV LINES		69.00		WOOD,	425.10	12.00	
28								
29	VOLTAGE OTHER							
30	VOLTAGE 765KV							
31	VOLTAGE 345KV							
32	VOLTAGE 138KV							
33	VOLTAGE LESS THAN 132							
34								
35								
36					TOTAL	3,937.64	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 2011/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	252,200	45,570	297,770					1
		1,497,837	1,497,837					2
	12,355		12,355					3
2-954 MCM	1,373,242	7,341,588	8,714,830					4
2-954 MCM	1,096,469	4,997,511	6,093,980					5
2-954 MCM		1,894,767	1,894,767					6
		-8,230	-8,230					7
397.5 MCM	210,485	1,035,095	1,245,580					8
	821		821					9
397.5 MCM	51,083	307,583	358,666					10
397.5 MCM	117,604	1,137,254	1,254,858					11
477 MCM	73,434	312,859	386,293					12
636 MCM	72,387	1,000,342	1,072,729					13
795 MCM	88,699	168,142	256,841					14
556.5 MCM	604	58,612	59,216					15
795 MCM	472,534	628,432	1,100,966					16
795 MCM	794,466	2,143,146	2,937,612					17
795 AA	16,279	100,911	117,190					18
1033 MCM	579,785	5,031,076	5,610,861					19
795 MCM		383,038	383,038					20
	64,293	430,007	494,300					21
	24,993	331,419	356,412					22
795 MCM	10,463	370,087	380,550					23
		151,111	151,111					24
	171,679	1,190,287	1,361,966					25
1033.5KCM	271,564	2,429,016	2,700,580					26
VARIOUS	1,578,542	24,862,483	26,441,025					27
								28
								29
				53,779	1,237,200		1,290,979	30
				79,369	1,825,907		1,905,276	31
				95,998	2,208,473		2,304,471	32
				125,896	2,896,316		3,022,212	33
								34
								35
	59,425,678	560,412,735	619,838,413	355,042	8,167,896		8,522,938	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 2011/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	NO LINES ALTERED						
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
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36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	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
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	ADAMS (IM)-IN	T	138.00	69.00	34.00
2		T	34.50	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	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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)	
115	1					1
4	1					2
90	1					3
			STATCAP	1	53	4
8	1					5
			STATCAP	1	14	6
20	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 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	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	CHURUBUSCO-IN	D	34.50	13.00	
10		D	34.50		
11	CLEVELAND-IN	D	138.00	13.09	
12	COLBY-MI	T	138.00	69.00	34.50
13		T	138.00	13.09	
14		T	69.00	34.50	
15		T	34.50		
16	COLFAX-IN	D	34.50	12.00	
17	COLOMA Y-MI	T	69.00	34.00	
18		T	69.00		
19	COLONY BAY-IN	D	69.00	13.00	
20		D	69.00	12.00	
21		D	69.00		
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	34.00
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 2011/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
11	1					9
			STATCAP	1	5	10
20	1					11
75	1					12
8	1					13
20	1					14
			STATCAP	1	17	15
22	1					16
22	1					17
			STATCAP	1	14	18
22	1					19
20	1					20
			STATCAP	1	16	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
1500	3	1				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 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	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	DRAGOON-IN	T	138.00	69.00	34.00
18		T	34.50		
19	DREWRYS-IN	D	34.50	13.09	
20		D	34.50	12.00	
21	DUMONT-IN	T	765.00		
22		T	765.00	345.00	34.50
23		T	765.00	345.00	17.00
24	DUNLAP-IN	T	138.00	69.00	34.00
25		T	138.00	13.09	
26		T	34.50		
27	EAST ELKHART-IN	T	345.00	137.50	13.80
28		T	138.00	69.00	34.00
29		T	34.50	7.20	
30	EAST SIDE (IM)-IN	D	138.00	13.09	
31	ELCONA-IN	D	138.00	13.09	
32	ELKHART HYDRO STAT-IN	T	34.50	13.00	
33		T	34.50		
34	ELMRIDGE-IN	D	34.50	13.00	
35	ELWOOD (IM)-IN	D	34.50	13.00	
36		D	34.50		
37	FAIRMOUNT-IN	D	34.50	7.20	
38	FALL CREEK-IN	T	345.00	138.00	34.00
39	FERGUSON-IN	D	69.00	13.00	
40	FISHER BODY-IN	D	138.00	13.80	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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)	
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
84	1					17
			STATCAP	1	12	18
8	1					19
8	1					20
			REACTOR	9	750	21
1500	3					22
1500	3					23
130	1					24
40	2					25
			STATCAP	1	29	26
450	1					27
84	1					28
1		1				29
45	2					30
22	1					31
8	1					32
			STATCAP	1	14	33
8	1					34
19	2					35
			STATCAP	1	5	36
11	1					37
672	1					38
20	1					39
100	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 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	FLORENCE ROAD-MI	D	69.00	12.00	
2		D	69.00		
3	FULTON (IM)-IN	D	34.50	13.00	
4	GARRETT (IM)-IN	T	69.00	34.00	
5		T	34.50	13.00	
6	GAS CITY-IN	D	34.50	13.00	
7		D	34.50		
8	GATEWAY (IM)-IN	T	69.00	34.00	
9		T	69.00		
10	GE TAYLOR STREET-IN	T	34.50	13.00	
11	GERMAN-IN	D	138.00	13.09	
12	GLENBROOK-IN	D	34.50	13.00	
13	GRABILL-IN	D	138.00	13.09	
14	GRANGER-IN	D	138.00	13.09	
15		D	138.00	12.47	
16	GRANT-IN	T	138.00	34.00	
17		T	138.00	13.09	
18	GREENLEAF-IN	D	34.50	13.09	
19	GREENTOWN-IN	T	765.00		
20	HACIENDA-IN	D	138.00	13.09	
21		D	138.00	12.47	
22	HADLEY-IN	D	69.00	13.00	
23	HAGAR-MI	D	69.00	12.00	
24	HAMILTON-IN	D	69.00	13.00	
25	HARLAN-IN	D	69.00	13.09	
26		D	69.00	13.00	
27	HARPER-IN	D	138.00	13.09	
28	HARTFORD-MI	T	138.00	69.00	34.00
29		T	69.00	12.00	
30		T	34.50		
31	HARTFORD CITY-IN	T	69.00	34.00	
32		T	69.00	13.00	
33		T	69.00		
34	HARVEST PARK-IN	D	34.50	13.00	
35	HAWTHORNE-MI	D	69.00	12.00	
36	HAYMOND-IN	D	34.50	13.00	
37		D	34.50	4.00	
38					
39					
40					

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Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
20	1					1
			STATCAP	1	19	2
20	1					3
10	1					4
1	3					5
20	1					6
			STATCAP	1	10	7
20	1					8
			STATCAP	1	13	9
29	4					10
47	2					11
40	2					12
20	1					13
20	1					14
20	1					15
30	1					16
	1					17
20	1					18
			REACTOR	2	200	19
20	1					20
25	1					21
40	2					22
11	1					23
11	1					24
13	1					25
5	1					26
20	1					27
129	1					28
11	1					29
			STATCAP	1	5	30
20	1					31
20	1					32
			STATCAP	1	16	33
20	1					34
22	1					35
24	2					36
16	2					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 2011/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	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	IUPU-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		

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Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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)	
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
2000	4					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 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	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	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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)	
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
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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.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	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	NEW CARLISLE-IN	T	138.00	34.50	
16		T	34.50	13.00	
17	NICKERSON-MI	D	138.00	13.09	
18	NILES-MI	T	69.00	34.00	
19		T	69.00	13.09	
20		T	69.00		
21	NOBLE-IN	D	69.00	13.00	
22	NORTH KENDALLVILLE-IN	D	69.00	12.00	
23	NORTH PORTLAND-IN	D	69.00	13.00	
24	NORTHLAND-IN	D	138.00	13.09	
25	NORTHWEST ELKHART-IN	D	34.50	13.00	
26		D	34.50		
27	OHIO OIL-IN	D	34.50	2.40	
28	OLIVE-IN	T	345.00	138.00	34.50
29		T	138.00	69.00	34.00
30		T	138.00	13.09	
31	OSOLO-IN	T	138.00	69.00	34.00
32		T	138.00	13.09	
33		T	34.50		
34	OSSIAN-IN	D	69.00	13.00	
35	PARNELL-IN	D	34.50	13.09	
36		D	34.50	13.00	
37	PEARL STREET-MI	D	34.50	12.00	
38	PENDLETON-IN	T	138.00	35.00	
39		T	34.50		
40	PETTIT AVENUE-IN	D	34.50	13.00	

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Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			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
30	1					15
8	1					16
20	1					17
45	1					18
20	1					19
			STATCAP	1	14	20
11	1					21
22	1					22
20	1					23
32	2					24
29	2					25
			STATCAP	1	14	26
6	6					27
675	1					28
27	1					29
9	1					30
75	1					31
42	2					32
			STATCAP	1	14	33
20	1					34
20	1					35
20	1					36
17	2					37
125	2					38
			STATCAP	2	47	39
20	1					40

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
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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.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	PIGEON RIVER-MI	D	69.00	12.00	
2	PINE ROAD-IN	D	138.00	13.09	
3	PIPE CREEK-IN	D	138.00	12.00	
4	POKAGON(MBH)-MI	T	138.00	69.00	13.00
5		T	69.00	13.00	
6		T	69.00		
7	PORTLAND (IM)-IN	D	69.00	13.00	
8	PRICE-IN	D	69.00	13.09	
9	RANDOLPH-IN	T	138.00	69.00	13.00
10		T	138.00	13.09	
11		T	69.00		
12		T	34.50	12.00	
13	REED-IN	D	138.00	13.09	
14	RIVERSIDE (IM)-MI	T	138.00	69.00	34.00
15		T	138.00	13.09	
16		T	138.00		
17	ROBISON PARK-IN	T	345.00	138.00	13.00
18		T	138.00		
19		T	138.00	70.50	36.20
20		T	138.00	13.09	
21	ROCKPORT-IN	T	765.00		
22		T	138.00		
23		T	34.50	13.00	
24	ROYERTON-IN	D	138.00	13.09	
25	SAUK TRAIL-MI	D	138.00	13.09	
26	SCHOOLCRAFT-MI	D	69.00	13.00	
27	SCOTTDALE-MI	D	34.50	13.00	
28	SISTER LAKES-MI	D	34.50	12.00	
29	SODUS-MI	D	138.00	13.09	
30	SORENSON-IN	T	345.00	138.00	34.00
31	SOUTH BEND-IN	T	138.00	69.00	34.00
32		T	138.00	34.00	
33		T	138.00	13.09	
34		T	138.00		
35	SOUTH BERNE-IN	D	69.00	12.00	
36	SOUTH DECATUR-IN	D	69.00	13.09	
37		D	69.00	13.00	
38	SOUTH ELWOOD-IN	T	138.00	34.00	
39		T	138.00	13.09	
40	SOUTH HAVEN-MI	T	69.00		

Name of Respondent: Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/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.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
20	1					1
20	1					2
20	1					3
115	1					4
5	1					5
			STATCAP	1	14	6
17	2					7
20	1					8
56	1					9
22	1					10
			STATCAP	1	14	11
4	1					12
22	1					13
134	2					14
20	1					15
			STATCAP	1	106	16
672	1					17
			STATCAP	1	86	18
90	1					19
40	2					20
			REACTOR	6	300	21
			REACTOR	2	40	22
2	2	1				23
11	1					24
20	1					25
22	1					26
11	1					27
15	2					28
11	1					29
1347	2					30
130	1					31
150	2					32
20	1					33
			STATCAP	1	53	34
12	1					35
20	1					36
20	1					37
30	1					38
20	1					39
			STATCAP	2	19	40

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Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	SOUTH SIDE (MARION)-IN	D	34.50	13.09	
2		D	34.50	4.00	
3	SOUTH SIDE (SOUTH BEND)-IN	D	138.00	13.09	
4	SOYA-IN	D	34.50	4.00	
5	SPRING STREET-IN	D	34.50	13.00	
6		D	34.50	12.00	
7	SPY RUN-IN	T	138.00	34.00	
8		T	138.00	13.09	
9		D	34.50		
10		D	34.50	12.00	
11		D	34.50	4.00	
12	ST. JOE-IN	D	69.00	13.09	
13	STATE STREET-IN	D	138.00	13.09	
14	STEVENSVILLE-MI	D	69.00	13.00	
15	STONE LAKE-MI	D	69.00	13.00	
16		D	69.00	12.00	
17	STUBEY ROAD-MI	D	69.00	12.00	
18		D	69.00		
19	STUDEBAKER-IN	D	138.00	13.80	
20		D	138.00	13.09	
21	SULLIVAN (IM)-IN	T	765.00		
22		T	765.00	345.00	34.50
23		T	765.00	345.00	34.00
24		T	138.00		
25	SUMMIT-IN	D	138.00	13.09	
26	SWANSON-IN	D	69.00	34.00	
27		D	69.00		
28	TANNERS CREEK-IN	T	345.00	141.00	13.20
29		T	345.00	137.50	13.14
30	THREE M-IN	D	69.00	4.00	
31	THREE RIVERS (FTW)-IN	D	34.50	14.40	
32		D	34.50	13.00	
33	THREE RIVERS (MBH)-MI	D	69.00	12.00	
34	TILLOTSON-IN	D	34.50	13.00	
35	TRIER-IN	D	138.00	13.09	
36	TWENTY FIRST STREET-IN	D	34.50	13.00	
37	TWENTY THIRD STREET (IM)-IN	T	138.00	69.00	34.00
38		T	34.50		
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
20	1					1
8	3					2
20	1					3
11	1					4
8	1					5
12	1					6
200	2					7
22	1	1				8
			STATCAP	1	10	9
20	1					10
8	1					11
20	1					12
22	1					13
19	2					14
7	1					15
9	1					16
11	1					17
			STATCAP	1	14	18
36	2					19
20	1					20
			REACTOR	3	150	21
500	1					22
2500	5	1				23
			REACTOR	1	20	24
40	2					25
45	2					26
			STATCAP	1	14	27
150	1					28
150	1					29
13	1					30
22	2					31
10	2					32
22	1					33
22	1					34
20	1					35
19	2					36
213	2					37
			STATCAP	2	29	38
						39
						40

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	TWIN BRANCH 138KV-IN	T	345.00	138.00	34.50
2		T	345.00	137.50	13.20
3		T	138.00	13.09	
4	TWIN BRANCH 34KV-IN	G	34.50	13.00	
5		G	34.50		
6	UPLAND-IN	D	69.00	13.20	
7	UTICA (IM)-IN	D	34.50	13.09	
8	VALLEY-MI	T	138.00	69.00	34.00
9		T	138.00		
10		T	34.50	34.00	
11		T	34.50		
12	VAN BUREN-IN	T	138.00	69.00	13.00
13	VICKSBURG-MI	D	69.00	13.09	
14		D	69.00	12.00	
15	WABASH AVENUE-IN	D	69.00	13.09	
16	WALLEN-IN	T	138.00	69.00	34.00
17		T	138.00	13.09	
18	WAYNE TRACE-IN	D	138.00	13.09	
19	WAYNEDALE-IN	D	138.00	13.09	
20		D	138.00	12.47	
21	WEBSTER-IN	D	34.50	14.00	
22		D	34.50	12.00	
23		D	13.80		
24	WES-DEL-IN	D	138.00	13.09	
25	WEST END-IN	D	34.50	13.00	
26		D	34.50	4.00	
27	WEST SIDE-IN	T	138.00	69.00	34.00
28		T	138.00	13.09	
29		T	34.50	27.00	
30		T	34.50		
31	WEST STREET-MI	D	138.00	13.09	
32	WHITAKER-IN	D	34.50	12.00	
33	WINCHESTER (IM)-IN	T	69.00	34.00	
34		T	69.00	13.00	
35		T	69.00		
36	WOODBURN-IN	D	69.00	13.00	
37					
38	94 STATIONS UNDER 10 MVA	T/D			
39					
40					

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Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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)	
675	1					1
450	1					2
20	1					3
3	1					4
			STATCAP	1	14	5
20	1					6
40	2					7
75	1					8
			STATCAP	1	44	9
11		1				10
			STATCAP	1	7	11
56	1					12
20	1					13
9	1					14
20	1					15
54	1					16
20	2					17
22	1					18
22	1					19
20	1					20
18	4					21
20	1					22
			STATCAP	2	14	23
22	1					24
9	2					25
8	1					26
84	1					27
42	2					28
45	1					29
			STATCAP	1	12	30
20	1					31
20	1					32
17	1					33
26	2					34
			STATCAP	2	22	35
11	1					36
						37
430	106					38
						39
						40

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, 2011

ELECTRIC DISTRIBUTION METERS AND LINE TRANSFORMERS

1. Report below the information called for concerning distribution watt-hour metes and line transformers.
2. Include watt-hour demand distribution meters, but not external demand meters.
3. Show in a footnote the number of distribution watt-hour meters or line transformers held by the respondent under lease from others, jointly owned with others, or held otherwise than by reason of sole ownership by the respondent. If 500 or more meters or line transformers are held under a lease, give name of lessor, date and period of lease, and annual rent. If 500 or more meters or line transformers are held other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of accounting for expenses between the parties, and state amounts and accounts affected in respondent's book of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Item	Number of Watt-Hours Meters	LINE TRANSFORMERS	
			Number	Total Capacity (In Mva)
	(a)	(b)	(c)	(d)
1	Number at Beginning of Year	960,852	192,450	8,685
2	Additions During Year	146,296		
3	Purchases	72,251	2,993	165
4	Associated with Utility Plant Acquired			
5	Other		0	0
6	TOTAL Additions (Enter Total of lines 2, 3, 4, & 5)	218,547	2,993	165
7	Reduction During Year			
8	Retirements	71,445	2,051	83
9	Associated with Utility Plant Sold	2,164		
10	Other	65,554	102	2
11	TOTAL Reductions (Enter Total of lines 7, 8, 9, & 10)	139,163	2,153	85
12	Number at End of Year (Lines 1+ 6 - 11)	1,040,236	193,290	8,765
13	In Stock	448,297	6,167	545
14	Locked Meters on Customers' Premises	28,483		
15	Inactive Transformers on System		445	22
16	In Customers' Use	563,180	186,678	8,198
17	In Companys' Use	276		
18	Total End of Year (Enter Total of lines 13 to 17. This line should equal line 11)	1,040,236	193,290	8,765

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