RECEIVED
JUL 26 2013
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF KENTUCKY POWER COMPANY FOR:	)	
(1) A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY	)	
AUTHORIZING THE TRANSFER TO THE COMPANY OF AN	)	
UNDIVIDED FIFTY PERCENT INTEREST IN THE MITCHELL	)	
GENERATING STATION AND ASSOCIATED ASSETS; (2) APPROVAL	)	
OF THE ASSUMPTION BY KENTUCKY POWER COMPANY OF	)	
CERTAIN LIABILITIES IN CONNECTION WITH THE TRANSFER OF	)	
THE MITCHELL GENERATING STATION; (3) DECLARATORY	)	CASE NO. 2012-00578
RULINGS; (4) DEFERRAL OF COSTS INCURRED IN CONNECTION	)	
WITH THE COMPANY'S EFFORTS TO MEET FEDERAL CLEAN AIR	)	
ACT AND RELATED REQUIREMENTS; 5) FOR ALL OTHER	)	
REQUIRED APPROVALS AND RELIEF	)	

KENTUCKY POWER COMPANY RESPONSES TO

ATTORNEY GENERAL'S POST HEARING DATA REQUESTS

July 26, 2013

VERIFICATION

The undersigned, Gregory G. Pauley, being duly sworn, deposes and says he is the President and Chief Operating Officer for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

Gregory G. Pauley

Gregory G. Pauley

COMMONWEALTH OF KENTUCKY)
) CASE NO. 2012-00578
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Gregory G. Pauley, this the 25 day of July 2013.

Judy K Rosquist 481393

Notary Public

My Commission Expires: January 23, 2017

VERIFICATION

The undersigned, Ranie K. Wohnhas, being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief

Ranie K. Wohnhas

Ranie K. Wohnhas

COMMONWEALTH OF KENTUCKY)
) CASE NO. 2012-00578
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Ranie K. Wohnhas, this the 25 day of July 2013.

Judy K Rosquist 481393

Notary Public

My Commission Expires: January 23, 2017

Kentucky Power Company

REQUEST

Please identify any bidding process used by Kentucky Power to obtain goods and services. If Kentucky Power does not use a bidding process for goods and services, state as such. Please include in your answer the process for utilizing identified vendors for the provision of goods and services.

RESPONSE

American Electric Power Service Corporation procures goods and services on behalf of all AEP operating companies, including Kentucky Power Company, using competitive bids. Operating company personnel are involved in the development of the competitive bid proposals and the evaluation of the tendered bids. On a limited basis, and only where AEPSC competitively procured goods and services cannot be obtained in a timely fashion, or because of the unique nature of the good or service to be obtained, Kentucky Power will purchase goods and services without competitive bidding. Procurement of goods and services on a an AEP-system wide basis allows the operating companies to obtain the best prices through their combined purchasing power.

WITNESS: Gregory G Pauley

Kentucky Power Company

REQUEST

Please identify the Company's anticipated costs associated with paragraph 14 of the Settlement Agreement. (p. 46 – Wohnhas) (Breathitt asked if we'd need to update our response to Staff 5-10)

RESPONSE

Paragraph 14 of the Stipulation and Settlement Agreement provides for the recovery of the costs associated with the retirement of Big Sandy Unit 2 *in toto*, and the retirement of the coal-related portions only of Big Sandy Unit 1. Under the terms of Paragraph 14 of the Stipulation and Settlement Agreement these retirement costs are to be recovered over a 25-year period, and will bear carrying costs equal to the Company's weighted average cost of capital (8.08%).

The retirement costs for Big Sandy Unit 2 *in toto* consist of decommissioning costs for Big Sandy Unit 2, and the costs associated with the amortization of the undepreciated balance of Big Sandy Unit 2. Although a study performed by Sargent and Lundy estimated that the cost of decommissioning the Big Sandy Plant as a whole (that is the cost of decommissioning both Big Sandy Unit 1 and Big Sandy Unit 2) would total $85.227 million, the study did not provide the cost of decommissioning Big Sandy Unit 2 alone. Kentucky Power believes that a reasonable basis for estimating the cost of decommissioning Big Sandy Unit 2 alone is to allocate the Sargent and Lundy estimate of the total plant decommissioning cost between Big Sandy Unit 1 and Big Sandy Unit 2 based upon their respective capacities (in MW) as part of the 1,078 MW of capacity provided by the Big Sandy Plant as a whole. Using this allocation method, Kentucky Power believes $63.24 million is a reasonable estimate of the cost of decommissioning Big Sandy Unit 2 alone ($85.227million x 0.742 [800MW/1078MW] = $63.24 million).

The Company's property records are maintained on a total plant basis that does not permit the specific identification of the undepreciated balance of Big Sandy Unit 2. The estimated undepreciated balance of the Big Sandy Plant *in toto* as of June 2015 (the expected retirement date of Big Sandy Unit 2) is $225.795 million. As was the case with the decommissioning costs, the Company believes a reasonable means of estimating the undepreciated balance of Big Sandy Unit 2 is to allocate the total undepreciated balance of the Big Sandy Plant based upon Big Sandy Unit 2's proportionate share of the total Big Sandy Plant's capacity. Using the same 74.2% allocation factor applied to the total decommissioning costs, Kentucky Power estimates that the undepreciated balance of Big Sandy Unit 2 alone is $225.795 million x 0.742 or $167.54 million.

Based upon these allocations, Kentucky Power estimates the costs associated with the retirement of Big Sandy Unit 2 *in toto* to be:

Cost of Decommissioning Big Sandy Plant	$ 63.24 million
Undepreciated Balance of Big Sandy Unit 2	$ 167.54 million
Total	$ 230.78 million

The Company cannot currently estimate the coal-related retirement costs for Big Sandy Unit 1. The coal-related retirement scope of Big Sandy Unit 1 is being developed as part of the on-going final engineering design for the Big Sandy Unit 1 conversion. It is nevertheless reasonable to assume that the coal-related retirement costs of Big Sandy Unit 1 would be less than the allocated retirement costs of Big Sandy Unit 1 as a whole.

WITNESS: Ranie K Wohnhas

KENTUCKY POWER COMPANY
2012 DEPRECIATION STUDY
CALCULATION OF TERMINAL SALVAGE AND REMOVAL AT RETIREMENT DATE
USING SARGENT & LUNDY STUDY DATA AND CONSUMER'S PRICE INDEX

Plant/Units	Terminal Salvage	Terminal Removal	Terminal Net Salvage	Average Inflation Rate (1)	Plant Retirement Year	Years Until Plant Retirement	Terminal Salvage at Retirement Date	Terminal Removal at Retirement Date	Terminal Net Salvage at Retirement Date
Big Sandy Plant									
S&L Estimate	$20,887,112	$49,718,898	($28,831,786)	2.50%	2015	2	$21,944,522	$52,235,917	($30,291,395)
Asbestos Cost	$0	$7,735,808	($7,735,808)				$0	$7,735,808	($7,735,808)
Ash Pond Closure	$0	$47,200,000	($47,200,000)				$0	$47,200,000	($47,200,000)
Total Big Sandy Plant	$20,887,112	$104,654,706	($83,767,594)				$21,944,522	$107,171,725	($85,227,203)
Mitchell Plant									
S&L Estimate	$19,031,883	$40,217,580	($21,185,697)	2.50%	2040	27	$37,070,302	$78,335,803	($41,265,501)
Ash Pond & Abestos Cost	$0	$9,358,153	($9,358,153)				$0	$9,358,153	($9,358,153)
Total Mitchell Plant	$19,031,883	$49,575,733	($30,543,850)				$37,070,302	$87,693,956	($50,623,654)
TOTALS	**$39,918,995**	**$154,230,439**	**($114,311,444)**				**$59,014,824**	**$194,865,681**	**($135,850,857)**

Note (1) Source Livingston Survey dated December 2012 (survey performed by Federal Reserve Bank of Philadelphia)

Kentucky Power Company

REQUEST

Please provide a copy of the Company's latest audited financials.

RESPONSE

A copy of the latest audited SEC financial for Ohio Power Company for the fiscal year ended December 31, 2012 is provided in AG PH-3 Attachment 1. A copy of the Company's latest audited FERC financial for Ohio Power Company is provided in AG PH-3 Attachment 2.

The financial reports provided are for Ohio Power Company because the request was for the audited financial that included Mitchell Plant. Also, see page 403.1 for Mitchell Plant specific data included in the FERC Form 1 in AG PH-3 Attachment 2.

WITNESS: Gregory G Pauley

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2012

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to__________

Commission File Number	Registrants; States of Incorporation; Address and Telephone Number	I.R.S. Employer Identification Nos.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
	1 Riverside Plaza, Columbus, Ohio 43215	
	Telephone (614) 716-1000	

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of each class	Name of Each Exchange on Which Registered
American Electric Power Company, Inc.	Common Stock, $6.50 par value	New York Stock Exchange
Appalachian Power Company	None	
Indiana Michigan Power Company	None	
Ohio Power Company	None	
Public Service Company of Oklahoma	None	
Southwestern Electric Power Company	None	

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant American Electric Power Company, Inc. is a well-known seasoned issuer, as defined in Rule 405 on the Securities Act.	Yes ☒	No ☐
Indicate by check mark if the registrants Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company, are well-known seasoned issuers, as defined in Rule 405 on the Securities Act.	Yes ☐	No ☒
Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.	Yes ☐	No ☒
Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.	Yes ☒	No ☐
Indicate by check mark whether American Electric Power Company, Inc., Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company have submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).	Yes ☒	No ☐
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (229.405 of this chapter) is not contained herein and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.	☒	

Indicate by check mark whether American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of 'large accelerated filer', 'accelerated filer' and 'smaller reporting company' in Rule 12b-2 of the Exchange Act. (Check One)

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	Smaller reporting company	☐

Indicate by check mark whether Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company are large accelerated filers, accelerated filers, non-accelerated filers or smaller reporting companies. See definitions of 'large accelerated filer', 'accelerated filer' and 'smaller reporting company' in Rule 12b-2 of the Exchange Act. (Check One)

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☒ (Do not check if a smaller reporting company)	Smaller reporting company	☐

Indicate by check mark if the registrants are shell companies, as defined in Rule 12b-2 of the Exchange Act. Yes ☐ No ☒

Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to such Form 10-K.

	Aggregate Market Value of Voting and Non-Voting Common Equity Held by Non-Affiliates of the Registrants as of June 30, 2012, the Last Trading Date of the Registrants' Most Recently Completed Second Fiscal Quarter	Number of Shares of Common Stock Outstanding of the Registrants at December 31, 2012
American Electric Power Company, Inc.	$19,378,167,963	485,668,370 ($6.50 par value)
Appalachian Power Company	None	13,499,500 (no par value)
Indiana Michigan Power Company	None	1,400,000 (no par value)
Ohio Power Company	None	27,952,473 (no par value)
Public Service Company of Oklahoma	None	9,013,000 ($15 par value)
Southwestern Electric Power Company	None	7,536,640 ($18 par value)

Note On Market Value Of Common Equity Held By Non-Affiliates

American Electric Power Company, Inc. owns all of the common stock of Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company (see Item 12 herein).

Documents Incorporated By Reference

Description	Part of Form 10-K into which Document is Incorporated
Portions of Annual Reports of the following companies for the fiscal year ended December 31, 2012: American Electric Power Company, Inc. Appalachian Power Company Indiana Michigan Power Company Ohio Power Company Public Service Company of Oklahoma Southwestern Electric Power Company	Part II
Portions of Proxy Statement of American Electric Power Company, Inc. for 2013 Annual Meeting of Shareholders.	Part III

This combined Form 10-K is separately filed by American Electric Power Company, Inc., Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Except for American Electric Power Company, Inc., each registrant makes no representation as to information relating to the other registrants.

You can access financial and other information at AEP's website, including AEP's Principles of Business Conduct (which also serves as a code of ethics applicable to Item 10 of this Form 10-K), certain committee charters and Principles of Corporate Governance. The address is www.AEP.com. AEP makes available, free of charge on its website, copies of its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC.

TABLE OF CONTENTS

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., an electric utility holding company.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP River Operations	AEP's inland river transportation subsidiary, AEP River Operations LLC, operating primarily on the Ohio, Illinois and lower Mississippi rivers.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West Companies	PSO, SWEPCo, TCC and TNC.
AEP Utilities	AEP Utilities, Inc., a subsidiary of AEP, formerly, Central and South West Corporation.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a subsidiary of AEP, an intermediate holding company for seven wholly-owned transmission companies.
AFUDC	Allowance for Funds Used During Construction.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
Buckeye	Buckeye Power, Inc., a nonaffiliated corporation.
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.
CRES provider	Competitive Retail Electric Service providers under Ohio law that target retail customers by offering alternative generation service.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
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.
EPACT	The Energy Policy Act of 2005.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP and MidAmerican Energy Holdings Company Texas Transco, LLC formed to own and operate electric transmission facilities in ERCOT.
FERC	Federal Energy Regulatory Commission.
Federal EPA	United States Environmental Protection Agency.
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.
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.
KPSC	Kentucky Public Service Commission.
KWh	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.

Term	Meaning
MPSC	Michigan Public Service Commission.
MW	Megawatt.
MWh	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NRC	Nuclear Regulatory Commission.
OATT	Open Access Transmission Tariff, filed with FERC.
OCC	Corporation Commission of the State of Oklahoma.
OHTCo	AEP Ohio Transmission Company, Inc.
OKTCo	AEP Oklahoma Transmission Company, Inc.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
REP	Texas Retail Electric Provider.
Rockport Plant	A generating plant, consisting of two 1,310 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.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity for AEP and SWEPCo.
SEC	U.S. Securities and Exchange Commission.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TA	Transmission Agreement, dated April 1, 1984, among APCo, I&M, KPCo and OPCo with AEPSC as agent.
TCA	Transmission Coordination Agreement dated January 1, 1997, by and among, PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two public utility subsidiaries.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations," but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue" and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, we undertake no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- The economic climate, growth or contraction within and changes in market demand and demographic patterns in our service territory.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load, customer growth and the impact of retail competition, particularly in Ohio.
- Weather conditions, including storms and drought conditions, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generating capacity and the performance of our generating plants.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity and transmission lines and facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation, including oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants and related assets.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.
- A reduction in the federal statutory tax rate could result in an accelerated return of deferred federal income taxes to customers.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance.
- Resolution of litigation.
- Our ability to constrain operation and maintenance costs.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, coal, natural gas and other energy-related commodities.
- Prices and demand for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Our ability to recover through rates or market prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.
- Volatility and changes in markets for electricity, coal, natural gas and other energy-related commodities.

- Changes in utility regulation, including the implementation of ESPs and the transition to market and expected legal separation for generation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP.
- Our ability to successfully manage negotiations with stakeholders and obtain regulatory approval to terminate the Interconnection Agreement.
- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of our debt.
- The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

The forward looking statements of AEP and its Registrant Subsidiaries speak only as of the date of this report or as of the date they are made. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information. For a more detailed discussion of these factors, see "Risk Factors" in Part I of this report.

PART I

ITEM 1. BUSINESS

GENERAL

Overview and Description of Subsidiaries

AEP was incorporated under the laws of the State of New York in 1906 and reorganized in 1925. It is a public utility holding company that owns, directly or indirectly, all of the outstanding common stock of its public utility subsidiaries and varying percentages of other subsidiaries.

The service areas of AEP's public utility subsidiaries cover portions of the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. The generating and transmission facilities of AEP's public utility subsidiaries are interconnected and their operations are coordinated. Transmission networks are interconnected with extensive distribution facilities in the territories served. The public utility subsidiaries of AEP have traditionally provided electric service, consisting of generation, transmission and distribution, on an integrated basis to their retail customers. Restructuring legislation in Michigan, Ohio and the ERCOT area of Texas has caused AEP public utility subsidiaries in those states to unbundle previously integrated regulated rates for their retail customers.

The AEP System is an integrated electric utility system. As a result, the member companies of the AEP System have contractual, financial and other business relationships with the other member companies, such as participation in the AEP System savings and retirement plans and tax returns, sales of electricity and transportation and handling of fuel. The companies of the AEP System also obtain certain accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost from a common provider, AEPSC.

As of December 31, 2012, the subsidiaries of AEP had a total of 18,513 employees. Because it is a holding company rather than an operating company, AEP has no employees. The public utility subsidiaries of AEP are:

APCo

Organized in Virginia in 1926, APCo is engaged in the generation, transmission and distribution of electric power to approximately 960,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. As of December 31, 2012, APCo had 2,128 employees. Among the principal industries served by APCo are paper, rubber, coal mining, textile mill products and stone, clay and glass products. In addition to its AEP System interconnections, APCo is interconnected with the following nonaffiliated utility companies: Carolina Power & Light Company, Duke Carolina and Virginia Electric and Power Company. APCo has several points of interconnection with Tennessee Valley Authority (TVA) and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

I&M

Organized in Indiana in 1907, I&M is engaged in the generation, transmission and distribution of electric power to approximately 584,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. As of December 31, 2012, I&M had 2,649 employees. Among the principal industries served are primary metals, transportation equipment, electrical and electronic machinery, fabricated metal products, rubber and chemicals and allied products, rubber products and transportation equipment. In addition to its AEP System interconnections, I&M is interconnected with the following nonaffiliated utility companies: Central Illinois Public Service Company, Duke Energy Ohio, Inc., Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, Duke Indiana and Richmond Power & Light Company. I&M is a member of PJM.

KPCo

Organized in Kentucky in 1919, KPCo is engaged in the generation, transmission and distribution of electric power to approximately 173,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. As of December 31, 2012, KPCo had 392 employees. Among the principal industries served are petroleum refining, coal mining and chemical production. In addition to its AEP System interconnections, KPCo is interconnected with the following nonaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

KGPCo

Organized in Virginia in 1917, KGPCo provides electric service to approximately 47,000 retail customers in Kingsport and eight neighboring communities in northeastern Tennessee. KGPCo does not own any generating facilities and is a member of PJM. It purchases electric power from APCo for distribution to its customers. As of December 31, 2012, KGPCo had 54 employees.

OPCo

Organized in Ohio in 1907 and re-incorporated in 1924, OPCo is engaged in the generation, transmission and distribution of electric power to approximately 1,459,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. OPCo also provides generation capacity to support shopping customer load, and will do so through mid-2015. As of December 31, 2012, OPCo had 3,131 employees. We have already obtained PUCO authorization for corporate separation and currently we are seeking regulatory approval from the FERC to transfer OPCo's generation assets to a newly formed wholly owned competitive Ohio generation affiliate as of January 1, 2014. Following this transaction, OPCo will continue to own transmission and distribution assets and to provide transmission and distribution services to its customers in Ohio. Among the principal industries served by OPCo are primary metals, chemicals and allied products, health services, electronic machinery, petroleum refining, and rubber and plastic products. In addition to its AEP System interconnection, OPCo is interconnected with the following nonaffiliated utility companies: Duke Ohio, The Cleveland Electric Illuminating Company, Dayton Power and Light Company, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

PSO

Organized in Oklahoma in 1913, PSO is engaged in the generation, transmission and distribution of electric power to approximately 535,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. As of December 31, 2012, PSO had 1,127 employees. Among the principal industries served by PSO are paper manufacturing and timber products, natural gas and oil extraction, transportation, non-metallic mineral production, oil refining and steel processing. In addition to its AEP System interconnections, PSO is interconnected with Empire District Electric Company, Oklahoma Gas and Electric Company, Southwestern Public Service Company and Westar Energy, Inc. PSO is a member of SPP.

SWEPCo

Organized in Delaware in 1912, SWEPCo is engaged in the generation, transmission and distribution of electric power to approximately 524,000 retail customers in northeastern and panhandle of Texas, northwestern Louisiana and western Arkansas and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. As of December 31, 2012, SWEPCo had 1,472 employees. Among the principal industries served by SWEPCo are natural gas and oil production, petroleum refining, manufacturing of pulp and paper, chemicals, food processing and metal refining. The territory served by SWEPCo also includes several military installations, colleges and universities. SWEPCo also owns and operates a lignite coal mining operation. In addition to its AEP System interconnections, SWEPCo is interconnected with Central Louisiana Electric Company, Empire District Electric Company, Entergy Corp. and Oklahoma Gas & Electric Company. SWEPCo is a member of SPP.

TCC

Organized in Texas in 1945, TCC is engaged in the transmission and distribution of electric power to approximately 799,000 retail customers through REPs in southern Texas. TCC sold all of its generation assets. As of December 31, 2012, TCC had 996 employees. Among the principal industries served by TCC are chemical and petroleum refining, chemicals and allied products, oil and gas extraction, food processing, metal refining, plastics and machinery equipment. In addition to its AEP System interconnections, TCC is a member of ERCOT.

TNC

Organized in Texas in 1927, TNC is engaged in the transmission and distribution of electric power to approximately 187,000 retail customers through REPs in west and central Texas. TNC's generating capacity has been transferred to an affiliate at TNC's cost pursuant to an agreement effective through 2027. As of December 31, 2012, TNC had 319 employees. Among the principal industries served by TNC are petroleum refining, agriculture and the manufacturing or processing of cotton seed products, oil products, precision and consumer metal products, meat products and gypsum products. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

WPCo

Organized in West Virginia in 1883 and reincorporated in 1911, WPCo provides electric service to approximately 41,000 retail customers in northern West Virginia. WPCo does not own any generating facilities. WPCo is a member of PJM. It purchases electric power from OPCo for distribution to its customers. As of December 31, 2012, WPCo had 51 employees. In December 2011, APCo and WPCo filed an application with the WVPSC requesting approval to merge WPCo into APCo. In December 2012, APCo and WPCo filed merger applications with the Virginia SCC and the FERC. A hearing at the Virginia SCC is scheduled for April 2013.

AEGCo

Organized in Ohio in 1982, AEGCo is an electric generating company. AEGCo sells power at wholesale to OPCo, I&M and KPCo. AEGCo has no employees.

Service Company Subsidiary

AEP also owns a service company subsidiary, AEPSC. AEPSC provides accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost to the AEP affiliated companies. The executive officers of AEP and certain of its public utility subsidiaries are employees of AEPSC. As of December 31, 2012, AEPSC had 4,787 employees.

AEPTCo

This wholly-owned intermediate holding company holds our seven transmission companies. The transmission companies are geographically aligned with our existing operating companies and develop and own new transmission assets that are physically connected to AEP's system. Individual transmission companies have obtained the approvals necessary to operate in Indiana, Michigan, Ohio, Oklahoma and West Virginia, subject to any applicable siting requirements, and are authorized to submit projects for commission approval in Virginia. Applications for transmission companies are pending with the applicable commissions in Arkansas, Kentucky and Louisiana. Neither AEPTCo nor the transmission companies have any employees. Instead, AEPSC and certain of our utility subsidiaries provide the services required by these entities.

CLASSES OF SERVICE

The principal classes of service from which the public utility subsidiaries of AEP derive revenues and the amount of such revenues during the year ended December 31, 2012 are as follows:

Description	AEP System (a)	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Utility Operations						
Retail Sales						
Residential Sales	$ 5,114,000	$ 1,159,576	$ 505,142	$ 1,636,808	$ 512,372	$ 512,578
Commercial Sales	3,216,000	576,153	377,302	945,233	331,125	404,204
Industrial Sales	2,772,000	701,603	430,042	742,235	209,446	298,604
PJM Net Charges	(43,000)	(13,049)	(9,003)	(18,831)	-	-
Provision for Rate Refund	(5,000)	-	-	(2,577)	-	(1,207)
Other Retail Sales	205,000	72,455	6,508	18,113	70,894	8,074
Total Retail	11,259,000	2,496,738	1,309,991	3,320,981	1,123,837	1,222,253
Wholesale						
Off-System Sales	1,909,000	409,527	481,000	661,513	37,484	247,118
Transmission	301,000	14,059	2,092	10,114	30,669	48,404
Total Wholesale	2,210,000	423,586	483,092	671,627	68,153	295,522
Other Electric Revenues	158,000	28,438	16,986	29,508	14,593	20,758
Other Operating Revenues	50,000	9,970	4,582	19,385	3,752	1,860
Sales to Affiliates	-	318,199	385,460	886,695	22,603	37,441
Total Utility Operating Revenues	13,677,000	3,276,931	2,200,111	4,928,196	1,232,938	1,577,834
Other	1,268,000	-	-	-	-	-
Total Revenues	$ 14,945,000	$ 3,276,931	$ 2,200,111	$ 4,928,196	$ 1,232,938	$ 1,577,834

(a) Includes revenues of other subsidiaries not shown. Intercompany transactions have been eliminated for the year ended December 31, 2012.

FINANCING

General

Companies within the AEP System generally use short-term debt to finance working capital needs. Short-term debt may also be used to finance acquisitions, construction and redemption or repurchase of outstanding securities until such needs can be financed with long-term debt. In recent history, short-term funding needs have been provided for by cash on hand, borrowing under AEP's revolving credit agreements and AEP's commercial paper program. Funds are made available to subsidiaries under the AEP corporate borrowing program. Certain public utility subsidiaries of AEP also sell accounts receivable to provide liquidity. See Management's Discussion and Analysis of Financial Condition and Results of Operations, included in the 2012 Annual Reports, under the heading entitled Financial Condition for additional information concerning short-term funding and our access to bank lines of credit, commercial paper and capital markets.

AEP's revolving credit agreements (which backstop the commercial paper program) include covenants and events of default typical for this type of facility, including a maximum debt/capital test and, for AEP and its significant subsidiaries, a $50 million cross-acceleration provision. As of December 31, 2012, AEP was in compliance with its debt covenants. With the exception of a voluntary bankruptcy or insolvency, any event of default has either or both a cure period or notice requirement before termination of the agreements. A voluntary bankruptcy or insolvency of AEP or one of its significant subsidiaries would be considered an immediate termination event. See Management's Discussion and Analysis of Financial Condition and Results of Operations, included in the 2012 Annual Reports, under the heading entitled Financial Condition for additional information with respect to AEP's credit agreements.

AEP's subsidiaries have also utilized, and expect to continue to utilize, additional financing arrangements, such as securitization financings and leasing arrangements, including the leasing of coal transportation equipment and facilities.

ENVIRONMENTAL AND OTHER MATTERS

General

AEP's subsidiaries are currently subject to regulation by federal, state and local authorities with regard to air and water-quality control and other environmental matters, and are subject to zoning and other regulation by local authorities. The environmental issues that we believe are potentially material to the AEP system are outlined below.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control mobile and stationary sources of air emissions. The major CAA programs affecting our power plants are described below. The states implement and administer many of these programs and could impose additional or more stringent requirements.

The Acid Rain Program

The 1990 Amendments to the CAA include a cap-and-trade emission reduction program for SO_2 emissions from power plants. By 2000, the program established a nationwide cap on power plant SO_2 emissions of 8.9 million tons per year, and required further reductions in 2010. The 1990 Amendments also contain requirements for power plants to reduce NO_x emissions through the use of available combustion controls.

The success of the SO_2 cap-and-trade program encouraged the Federal EPA and the states to use it as a model for other emission reduction programs. We continue to meet our obligations under the Acid Rain Program through the installation of controls, use of alternate fuels and participation in the emissions allowance markets. Subsequent programs developed by the Federal EPA have imposed more stringent SO_2 and NO_x emission reduction requirements than the Acid Rain Program on many of our facilities. We have installed additional controls and taken other actions to achieve compliance with these programs.

National Ambient Air Quality Standards

The CAA requires the Federal EPA to review the available scientific data for criteria pollutants periodically and establish a concentration level in the ambient air for those substances that is adequate to protect the public health and welfare with an extra safety margin. The Federal EPA also can list additional pollutants and develop concentration levels for them. These concentration levels are known as national ambient air quality standards (NAAQS).

Each state identifies the areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (nonattainment areas). Each state must develop a state implementation plan (SIP) to bring nonattainment areas into compliance with the NAAQS and maintain good air quality in attainment areas. All SIPs are submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA develops and implements a plan. As the Federal EPA reviews the NAAQS and establishes new concentration levels, the attainment status of areas can change and states may be required to develop new SIPs. In 2008, the Federal EPA issued revised NAAQS for both ozone and fine particulate matter ($PM_{2.5}$). The $PM_{2.5}$ standard was remanded by the D.C. Circuit Court of Appeals, and a new rule was signed by the administrator in December 2012 that lowers the annual standard. A new ozone standard is also under development and is expected to be proposed in 2013. The Federal EPA also adopted a new short-term standard for SO_2 in 2010, a lower standard for NO_x in 2010, and a lower standard for lead in 2008. The existing standard for carbon monoxide was retained in 2011. The states will develop new SIPs for these standards, which could result in additional emission reductions being required from our facilities.

In 2005, the Federal EPA issued the Clean Air Interstate Rule (CAIR), which requires additional reductions in SO_2 and NO_x emissions from power plants and assists states developing new SIPs to meet the NAAQS. For additional information regarding CAIR, see Management's Discussion and Analysis of Financial Condition and Results of Operations under the headings entitled Environmental Issues – Clean Air Act Requirements. In August 2011, the Federal EPA issued a final rule to replace CAIR (the Cross State Air Pollution Rule (CSAPR)) that would impose new and more stringent requirements to control SO_2 and NO_x emissions from fossil fuel-fired electric generating units in 27 states and the District of Columbia. Petitions for review were filed with the U.S. Court of Appeals for the District of Columbia Circuit, and CSAPR was vacated. CAIR remains in effect until the Federal EPA develops a replacement rule. For additional information regarding CSAPR, see Management's Discussion and Analysis of Financial Condition and Results of Operations under the headings entitled Environmental Issues – Clean Air Act Requirements.

Hazardous Air Pollutants

As a result of the 1990 Amendments to the CAA, the Federal EPA investigated hazardous air pollutant (HAP) emissions from the electric utility sector and submitted a report to Congress, identifying mercury emissions from coal-fired power plants as warranting further study. In 2011, the Federal EPA issued a final rule setting Maximum Achievable Control Technology (MACT) standards for new and existing coal and oil-fired utility units and New Source Performance Standards (NSPS) for emissions from new and modified power plants. For additional information regarding the Utility MACT, see Management's Discussion and Analysis of Financial Condition and Results of Operations under the headings entitled Environmental Issues – Clean Air Act Requirements.

Regional Haze

The CAA establishes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing impairment of visibility in these areas (Regional Haze program). In 2005, the Federal EPA issued its Clean Air Visibility Rule (CAVR), detailing how the CAA's best available retrofit technology requirements will be applied to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants.

PSO is in the process of implementing a settlement with the Federal EPA in order to comply with the Regional Haze program requirements in that state. For additional information regarding CAVR and the Regional Haze program requirements, see Management's Discussion and Analysis of Financial Condition and Results of Operations under the headings entitled Environmental Issues – Clean Air Act Requirements.

CO_2 Regulation

In the absence of comprehensive climate change legislation, the Federal EPA has taken action to regulate CO_2 emissions under the existing requirements of the CAA. Such actions are being legally challenged by numerous parties. For additional information regarding the Federal EPA action taken to regulate CO_2 emissions, see Management's Discussion and Analysis of Financial Condition and Results of Operations under the headings entitled Environmental Issues – Clean Air Act Requirements.

Our fossil fuel-fired generating units are large sources of CO_2 emissions. If substantial CO_2 emission reductions are required, there will be significant increases in capital expenditures and operating costs which would hasten the ultimate retirement of older, less-efficient, coal-fired units. To the extent we install additional controls on our generating plants to limit CO_2 emissions and receive regulatory approvals to increase our rates, return on capital investment would have a positive effect on future earnings. Prudently incurred capital investments made by our subsidiaries in rate-regulated jurisdictions to comply with legal requirements and benefit customers are generally included in rate base for recovery and earn a return on investment. We would expect these principles to apply to investments made to address new environmental requirements. However, requests for rate increases reflecting these costs can affect us adversely because our regulators could limit the amount or timing of increased costs that we would recover through higher rates. To the extent our costs are relatively higher than our competitors' costs, it could reduce our off-system sales or cause us to lose customers in jurisdictions that permit customers to choose their supplier of generation service.

Several states have adopted programs that directly regulate CO_2 emissions from power plants, but none of these programs are currently in effect in states where we have generating facilities. Some of our states have established mandatory or voluntary programs to increase the use of energy efficiency, alternative energy, or renewable energy sources (Arkansas, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Texas, Virginia, and West Virginia). We are taking steps to comply with these requirements primarily through entering into power supply agreements giving us access to power generated by wind turbines.

Clean Water Act Requirements

Our operations are also subject to the Federal Clean Water Act, which prohibits the discharge of pollutants into waters of the United States except pursuant to appropriate permits, and regulates systems that withdraw surface water for use in our power plants. In April 2011, the Federal EPA issued a proposed rule setting forth standards for existing power plants that will reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. The proposed standards affect all plants withdrawing more than two million gallons of cooling water per day and establish specific intake design and intake velocity standards meant to allow fish to avoid or escape impingement. Compliance with this standard is required within eight years of the effective date of the final rule. The proposed standard for entrainment for existing facilities requires a site-specific evaluation of the available measures for reducing entrainment. We submitted comments on the proposal in July and August 2011. We expect the Federal EPA to issue revised rules in 2013.

The Federal EPA is also engaged in rulemaking to update the technology-based standards that govern discharges from new and existing power plants under the Clean Water Act's National Pollutant Discharge Elimination System program. These standards were last updated over 20 years ago, and the Federal EPA has issued two rounds of information collection requests to inform its rulemaking. In October 2009, the Federal EPA issued a final report for the power plant sector and determined that revisions to its existing standards are necessary. We expect the Federal EPA to propose revised standards in 2013. Until new standards are proposed, we cannot predict the outcome or impact of these rules on our operations.

Coal Ash Regulation

Our operations produce a number of different coal combustion products, including fly ash, bottom ash, gypsum and other materials. The Federal EPA completed an extensive study of the characteristics of coal ash in 2000 and concluded that combustion wastes do not warrant regulation as hazardous waste. In December 2008, the breach of a dike at the Tennessee Valley Authority's Kingston Station resulted in a spill of several million cubic yards of ash into a nearby river and onto private properties, prompting federal and state reviews of ash storage and disposal practices at many coal-fired electric generating facilities, including ours. AEP operates 37 ash ponds and we manage these ponds in a manner that complies with state and local requirements, including dam safety rules designed to assure the structural integrity of these facilities. We also operate a number of dry disposal facilities in accordance with state standards, including ground water monitoring and other applicable standards. In June 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at coal-fired electric generating units. For additional information regarding the Federal EPA action taken to regulate the disposal and beneficial re-use of coal combustion residuals and the potential impact on our operations, see Management's Discussion and Analysis of Financial Condition and Results of Operations under the headings entitled Environmental Issues – Coal Combustion Residual Rule.

Climate Change – Position and Strategy

We continue to support a federal legislative approach to energy policy as the most effective means of reducing emissions of CO_2 and other greenhouse gases (generally referred to as CO_2) that recognizes that a reliable and affordable electricity supply is vital to economic recovery and growth. We do not believe regulating CO_2 emissions under the Clean Air Act is the appropriate solution. During the past decade, we have taken voluntary actions to reduce and offset our CO_2 emissions. Unfortunately, two of the voluntary programs that helped businesses such as AEP to set quantitative commitments no longer exist. The Federal EPA's Climate Leaders Program and the Chicago Climate Exchange both ended their reduction obligations at the end of 2010. However, through these programs and others, we voluntarily reduced our CO_2 emissions by approximately 96 million metric tons during the 2003 to 2010 period. We expect our emissions to continue to decline over time as we diversify our generating sources and operate fewer coal units. The projected decline in coal-fired generation is due to a number of factors including the ongoing cost of operating older units, the relative cost of coal and natural gas as fuel sources, increasing environmental regulations requiring significant capital investments and changing commodity market fundamentals. Our strategy for this transformation is to protect the reliability of the electric system and reduce our emissions by pursuing multiple options. These include diversifying our fuel portfolio and generating more electricity from natural gas, increasing energy efficiency and investing in renewable resources, where there is regulatory support. Meanwhile the Federal EPA began regulating CO_2 emissions from large stationary sources such as power plants in 2012 under the NSR prevention of significant deterioration and Title V operating permit programs.

In March 2012 the Federal EPA proposed a Carbon Pollution Standard for New Power Plants. This regulation, based on EPA authority under section 111(b) of the Clean Air Act, would establish New Source Performance Standards for CO_2 for new fossil-fueled-fired electric generating units. The proposed regulation could limit the ability to construct new coal-fired facilities in the future due to strict emission limits if finalized. AEP does not currently have plans to permit or construct any new coal-fired facilities and the proposed rule does not directly impact existing facilities.

For additional information on legislative and regulatory responses to greenhouse gases, including limitations on CO_2 emissions, see Management's Discussion and Analysis of Financial Condition and Results of Operations under the headings entitled Environmental Issues – Climate Change. Specific steps taken to reduce CO_2 emissions include the following:

Renewable Sources of Energy

Some of our states have established mandatory or voluntary programs to increase the use of energy efficiency, alternative energy, or renewable energy sources (Arkansas, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Texas, Virginia, and West Virginia). At the end of 2012 and in support of our goals or requirements, the company had long-term contracts for 1,984 MW of wind and 10 MW of solar power for a combined total of 1,994 MW to serve its regulated operating company customers. We actively manage our compliance position and are on pace to meet the relevant requirements or benchmarks in each applicable jurisdiction.

End User Energy Efficiency

In 2008, AEP established a goal to reduce demand by 1,000 megawatts (MW) and energy consumption by 2,250,000 megawatt-hours (MWh) by the end of 2012. Since that time, AEP Operating Companies have implemented a wide variety of new consumer programs across most of the states we serve. Over 100 energy efficiency and demand response programs and tariffs are now in place.

Preliminary estimates indicate that we have achieved our goal. From 2008 through 2012, AEP achieved 3,016,400 MWh of energy reduction and 1,011 MW of demand reduction, or 134% and 101% of goal, respectively. For the same period, AEP Operating Companies have invested over $368 million in energy efficiency and demand response initiatives. Final results are subject to independent third party evaluation and verification of savings, as required in some jurisdictions.

Energy efficiency and demand reduction programs have received regulatory support in most of the states we serve, and appropriate cost recovery will be essential for us to continue and expand these consumer offerings. Appropriate recovery of program costs, lost revenues, and an opportunity to earn a reasonable return ensures that energy efficiency programs are considered equally with supply side investments. Going forward, we will work closely with regulators to ensure that plans are in place to meet specific regulatory and legislative energy efficiency and/or demand reduction targets present in the respective jurisdictions.

gridSMART®

AEP's *gridSMART®* initiative is designed to demonstrate the potential benefits of the smart grid by integrating advanced grid technologies into existing electric networks. AEP is deploying smart grid technologies in several jurisdictions with regulatory support.

- AEP Ohio is deploying a comprehensive suite of smart grid technologies in an innovative demonstration project with 110,000 customers. The $150 million project is being funded through a $75 million federal grant, PUCO cost recovery support and vendor in-kind contributions.
- AEP Texas is deploying a one million meter smart grid network, along with $1 million in energy use display devices for low income customers. The $308 million project is targeted for completion by the end of 2013. We are recovering the costs through an 11-year surcharge.
- I&M has deployed a smart grid network to 10,000 customers. The $7 million project was funded pursuant to a settlement agreement approved by the IURC.
- PSO has deployed smart meters to approximately 31,000 customers, 14,000 of which will be served on circuits equipped with advanced grid management technologies. The project is being financed through a $8.75 million American Reinvestment and Recovery Act low-interest loan from the Oklahoma Department of Commerce with $2 million annual revenues for cost recovery approved by the Oklahoma Corporation Commission.

Current and Projected CO_2 Emission

Our total CO_2 emissions in 2011 (not including our ownership in the Kyger Creek and Clifty Creek plants) were approximately 136 million metric tons. Our 2012 emissions decreased to approximately 122 million metric tons. We expect overall increases in CO_2 emissions during the next few years to be small, if any, as our sales and generation rebound somewhat from recession lows in 2009. However, over much of the remainder of the decade we expect emissions to decline as modest sales growth is offset by retirements of older, less efficient coal-fired units and increased utilization of natural gas.

Corporate Governance

In response to environmental issues and in connection with its assessment of our strategic plan, our Board of Directors continually reviews the risks posed by our actions. The Board of Directors is informed of any new material environmental issues, including changes to regulations and proposed legislation. The Board's Committee on Directors and Corporate Governance oversees the company's annual Corporate Accountability Report, which includes information on environmental issues.

Other Environmental Issues and Matters

We are engaged in litigation regarding regulated air emissions and/or whether emissions from coal-fired generating plants cause or contribute to global warming. See Management's Discussion and Analysis of Financial Condition and Results of Operations under the heading entitled Litigation – Environmental Issues and Note 5 to the consolidated financial statements entitled Commitments, Guarantees and Contingencies, included in the 2012 Annual Reports, for further information.

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 imposes costs for environmental remediation upon owners and previous owners of sites, as well as transporters and generators of hazardous material disposed of at such sites. See Note 5 to the consolidated financial statements entitled Commitments, Guarantees and Contingencies, included in the 2012 Annual Reports, under the heading entitled The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation for further information.

Environmental Investments

Investments related to improving AEP System plants' environmental performance and compliance with air and water quality standards during 2010, 2011 and 2012 and the current estimates for 2013, 2014 and 2015 are shown below, in each case excluding equity AFUDC and capitalized interest. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends and the ability to access capital. AEP expects to make substantial investments in future years in addition to the amounts set forth below in connection with the modification and addition of facilities at generating plants for environmental quality controls. Such future investments are needed in order to comply with air and water quality standards that have been adopted and have deadlines for compliance after 2012 or have been proposed and may be adopted. Future investments could be significantly greater if emissions reduction requirements are accelerated or otherwise become more onerous or if CO_2 becomes regulated at existing facilities. While we expect to recover our expenditures for pollution control technologies, replacement generation and associated operating costs from customers through regulated rates (in regulated jurisdictions) or market prices, without such recovery, those costs could impact future net income and cash flows and impact financial condition. The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the AEP System. See Management's Discussion and Analysis of Financial Condition and Results of Operations under the heading entitled Environmental Issues and Note 5 to the consolidated financial statements, entitled Commitments, Guarantees and Contingencies, included in the 2012 Annual Reports, for more information regarding environmental expenditures in general.

Historical and Projected Environmental Investments

	2010 Actual	2011 Actual	2012 Actual	2013 Estimate	2014 Estimate	2015 Estimate
			(in thousands)			
Total AEP System (a)	$ 303,800	$ 186,800	$ 235,400	$ 544,000	$ 760,000	$ 850,000
APCo	202,700	68,900	50,800	59,000	48,000	84,000
I&M	8,100	5,900	30,400	42,000	84,000	88,000
OPCo	97,400	63,000	66,200	191,000	185,000	159,000
PSO	1,200	6,500	26,100	64,000	82,000	98,000
SWEPCo (b)	(10,500)	11,000	23,800	143,000	241,000	325,000

(a) Includes expenditures of the subsidiaries shown and other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies.
(b) SWEPCo 2010 actual environmental cost includes reclassifications of project costs for suspended capital projects.

The preceding discussion of environmental investments and plans for future years reflects the ownership of plants as of December 31, 2012. The AEP East Companies have filed with the FERC to terminate the Interconnection Agreement and for OPCo to transfer facilities to APCo, KPCo and AEPGenCo. Management expects the transfers will be effective December 31, 2013.

Electric and Magnetic Fields (EMF)

EMF are found everywhere there is electricity. Electric fields are created by the presence of electric charges. Magnetic fields are produced by the flow of those charges. This means that EMF are created by electricity flowing in transmission and distribution lines, electrical equipment, household wiring and appliances. A number of studies in the past have examined the possibility of adverse health effects from EMF. While some of the epidemiological studies have indicated some association between exposure to EMF and health effects, none has produced any conclusive evidence that EMF does or does not cause adverse health effects.

Management cannot predict the ultimate impact of the question of EMF exposure and adverse health effects. If further research shows that EMF exposure contributes to increased risk of cancer or other health problems, or if the courts conclude that EMF exposure harms individuals and that utilities are liable for damages, or if states limit the strength of magnetic fields to such a level that the current electricity delivery system must be significantly changed, then the results of operations and financial condition of AEP and its operating subsidiaries could be materially affected unless these costs can be recovered from customers.

UTILITY OPERATIONS

GENERAL

Utility operations constitute most of AEP's business operations. Utility operations include (a) the generation, transmission and distribution of electric power to retail customers and (b) the supplying and marketing of electric power at wholesale (through the electric generation function) to other electric utility companies, municipalities and other market participants. AEPSC, as agent for AEP's public utility subsidiaries, performs marketing, generation dispatch, fuel procurement and power-related risk management and trading activities.

ELECTRIC GENERATION

Facilities

As of December 31, 2012, AEP's public utility subsidiaries owned or leased approximately 37,300 MW of domestic generation. See Item 2 – Properties for more information regarding AEP's generation capacity.

Interconnection Agreement

APCo, I&M, KPCo, OPCo and AEPSC are parties to the Interconnection Agreement, which was originally approved by the FERC in 1951 and subsequently amended in 1951, 1962, 1975, 1979 (twice) and 1980. This agreement defines how the member companies share the costs and benefits associated with their generating plants. This sharing is based upon each company's "member load ratio." The member load ratio is calculated monthly by dividing each company's highest monthly peak demand for the last twelve months by the aggregate of the highest monthly peak demand for the last twelve months for all member companies. The member load ratio multiplied by the aggregate generation capacity of all the member companies determines each member company's capacity obligation. The difference between each member company's obligation and its own generation capacity determines the capacity surplus or deficit of each member company. The agreement requires the deficit companies to make monthly capacity equalization payments to the surplus companies based on the surplus companies' average fixed cost of generation. Member companies that deliver energy to other member companies to meet their internal load requirements are reimbursed at average variable costs. In addition, all member companies share off-system sales margins based upon each member company's member load ratio. Consequently, the agreement provides a strong risk sharing and mitigation arrangement among the member companies. As of December 31, 2012, the member-load-ratios were as follows:

	Peak Demand	Member-Load Ratio
	(MWs)	(%)
APCo	6,881	30
I&M	4,726	21
KPCo	1,378	6
OPCo	9,670	43

APCo, I&M, KPCo and OPCo are parties to the AEP System Interim Allowance Agreement (Allowance Agreement), which has been approved by the FERC and provides, among other things, for the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement. The following table shows the net (credits) or charges allocated among the parties under the Interconnection Agreement during the years ended December 31, 2012, 2011 and 2010:

	Years Ended December 31, 2012	2011	2010
		(in thousands)	
APCo	$ 494,400	$ 632,100	$ 757,900
I&M	(118,400)	(183,700)	(236,900)
KPCo	93,200	48,400	49,400
OPCo	(469,200)	(496,800)	(570,400)

Termination of the Interconnection Agreement

In October 2012, AEP submitted several applications with the FERC requesting termination of the Interconnection Agreement, termination of the Allowance Agreement, approval of a new Power Coordination Agreement among APCo, I&M and KPCo and the transfer of OPCo's generating assets to either a new wholly owned unregulated generation company or to APCo and KPCo to fully separate OPCo's generating assets from its distribution and transmission operations. See Note 3 to the consolidated financial statements, entitled Rate Matters, included in the 2012 Annual Reports, for additional information regarding the termination of the Interconnection Agreement and transfer of OPCo's generation assets.

CSW Operating Agreement

PSO, SWEPCo and AEPSC are parties to the CSW Operating Agreement, which has been approved by the FERC. The CSW Operating Agreement requires these public utility subsidiaries to maintain adequate annual planning reserve margins and requires the subsidiaries that have capacity in excess of the required margins to make such capacity available for sale to other public utility subsidiary parties as capacity commitments. Parties are compensated for energy delivered to the recipients based upon the deliverer's incremental cost plus a portion of the recipient's savings realized by the purchaser that avoids more costly alternatives. Revenues and costs arising from third party sales in their region are generally shared based on the amount of energy each west zone public utility subsidiary contributes that is sold to third parties.

The following table shows the net (credits) or charges allocated among the parties under the CSW Operating Agreement during the years ended December 31, 2012, 2011 and 2010:

	Years Ended December 31,		
	2012	2011	2010
		(in thousands)	
PSO	$ 42,555	$ 33,091	$ 20,222
SWEPCo	(42,555)	(33,091)	(20,222)

Power generated by or allocated or provided under the Interconnection Agreement or CSW Operating Agreement to any public utility subsidiary is primarily sold to customers by such public utility subsidiary at rates approved by the public utility commission in the jurisdiction of sale (except in Ohio, where generation rates are currently priced using a hybrid approach that incorporates components of cost and market). See Regulation – Rates under Item 1, Utility Operations.

Under both the Interconnection Agreement and CSW Operating Agreement, power that is not needed to serve the native load of our public utility subsidiaries is sold in the wholesale market by AEPSC on behalf of those subsidiaries. See Risk Management and Trading, below, for a discussion of the trading and marketing of such power.

AEP's System Integration Agreement provides for the integration and coordination of AEP's East Companies, PSO and SWEPCo. 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). It 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 for activities within each zone.

Risk Management and Trading

As agent for AEP's public utility subsidiaries, AEPSC sells excess power into the market and engages in power, natural gas, coal and emissions allowances risk management and trading activities focused in regions in which AEP traditionally operates and in adjacent regions. These activities primarily involve the purchase and sale of electricity (and to a lesser extent, natural gas, coal and emissions allowances) under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, over-the-counter swaps and options. The majority of forward contracts are typically settled by entering into offsetting contracts. These transactions are executed with numerous counterparties or on exchanges. Counterparties and exchanges may require cash or cash related instruments to be deposited on these transactions as margin against open positions. As of December 31, 2012, counterparties posted approximately $8 million in cash, cash equivalents or letters of credit with AEPSC for the benefit of AEP's public utility subsidiaries (while, as of that date, AEP's public utility subsidiaries posted approximately $89 million with counterparties and exchanges). Since open trading contracts are valued based on market prices of various commodities, exposures change daily. See Management's Discussion and Analysis of Financial Condition and Results of Operations, included in the 2012 Annual Reports, under the heading entitled Quantitative and Qualitative Disclosures About Market Risk for additional information.

Fuel Supply

The following table shows the sources of fuel used by the AEP System:

	2012	2011	2010
Coal and Lignite	71%	78%	82%
Natural Gas	17%	11%	8%
Nuclear	11%	10%	9%
Hydroelectric and other	<1%	<1%	<1%

A price increase/decrease in one or more fuel sources relative to other fuels may result in the decreased/increased use of other fuels. AEP's overall 2012 fossil fuel costs are down approximately 2% on a dollar per MMBtu basis from 2011 due primarily to the favorable impact of low natural gas prices.

Coal and Lignite

AEP's public utility subsidiaries procure coal and lignite under a combination of purchasing arrangements including long-term contracts, affiliate operations and spot agreements with various producers and coal trading firms. Coal consumption in 2012 was down significantly from the same period in 2011 for the reasons discussed below. The AEP System average target level for coal inventory ranges from 35 to 40 days and as of December 31, 2012, the AEP System average for coal inventories was 44 days.

Management believes that AEP's public utility subsidiaries will be able to secure and transport coal and lignite of adequate quality and in adequate quantities to operate their coal and lignite-fired units. Through subsidiaries, AEP owns, leases or controls more than 7,600 railcars, approximately 600 barges, 15 towboats, and a coal handling terminal with approximately 18 million tons of annual capacity to move and store coal for use in our generating facilities. See AEP River Operations for a discussion of AEP's for-profit coal and other dry-bulk commodity transportation operations that are not part of AEP's Utility Operations segment.

Spot market prices for certain coals utilized by AEP decreased significantly in the first half of 2012, but made a modest recovery by the end of the year. The general decrease in spot coal prices during the year can be attributed to the persistently weak demand for domestic coal driven, in large part, by low natural gas prices and the displacement of coal generation with natural gas resources. Most of the coal purchased by AEP is procured through term contracts. As those contracts expire, they can be replaced at the new market price with an impact in subsequent periods. The average cost per ton for coal delivered in 2012 increased from the prior year.

The following table shows the amount of coal and lignite delivered to the AEP System plants during the past three years and the average delivered price of coal purchased by AEP System companies:

	2012	2011	2010
Total coal delivered to AEP System plants (thousands of tons)	60,054	62,956	64,614
Average cost per ton of coal delivered	$ 49.22	$ 46.76	$ 44.82

The coal supplies at AEP System plants vary from time to time depending on various factors, including, but not limited to, demand for electric power, unit outages, transportation infrastructure limitations, space limitations, plant coal consumption rates, availability of acceptable coals, labor issues and weather conditions, which may interrupt production or deliveries. As of December 31, 2012, the AEP System's coal inventory was approximately 44 days of full load burn.

Natural Gas

Through its public utility subsidiaries, AEP consumed nearly 220 billion cubic feet of natural gas during 2012 for generating power. This represents an increase of 32% from 2011 and continues a trend that began in 2010. Since 2009, AEP's natural gas consumption has increased approximately 130%. The increased natural gas consumption is attributable to the addition of the Stall and Dresden natural gas combined cycle units in June 2010 and January 2012, respectively, along with increased operation of the Lawrenceburg and Waterford combined cycle units. The efficient heat rates of these units (low 7,000 British thermal units/KWh range) coupled with sustained lower natural gas prices have supported the increased operation of AEP's combined cycle natural gas units. A mild 2011-12 winter and the continuation of high levels of production from shale gas developments led to higher U.S. natural gas inventories and continued to place downward pressure on natural gas prices as a result of more abundant supplies, making power generated from these units more economic. Several of AEP's natural gas-fired power plants are connected to at least two pipelines, which allows greater access to competitive supplies and improves delivery reliability. A portfolio of term, monthly, seasonal firm and daily peaking commodity and transportation agreements (that are entered into on a competitive basis and based on market prices) supplies natural gas requirements for each plant, as appropriate.

The following table shows the amount of natural gas delivered to the AEP System plants during the past three years and the average delivered price of natural gas purchased by AEP System companies:

	2012	2011	2010
Total natural gas delivered to AEP System plants (billion cubic feet)	220.0	166.8	133.6
Average price per MMBtu of purchased natural gas	$ 3.01	$ 4.48	$ 4.80

Nuclear

I&M has made commitments to meet the current nuclear fuel requirements of the Cook Plant. I&M has made and will make purchases of uranium in various forms in the spot, short-term and mid-term markets. I&M also continues to lease a portion of its nuclear fuel.

For purposes of the storage of high-level radioactive waste in the form of spent nuclear fuel, I&M completed modifications to its spent nuclear fuel storage pool more than 10 years ago. I&M entered into an agreement to provide for onsite dry cask storage of spent nuclear fuel to permit normal operations to continue. I&M is scheduled to conduct further dry cask loading and storage projects on an ongoing periodic basis. I&M began and completed its initial loading of spent nuclear fuel into the dry casks in 2012, which consisted of 12 casks (32 spent nuclear fuel assemblies contained within each).

Nuclear Waste and Decommissioning

As the owner of the Cook Plant, I&M has a significant future financial commitment to dispose of spent nuclear fuel and decommission and decontaminate the plant safely. The cost to decommission a nuclear plant is affected by NRC regulations and the spent nuclear fuel disposal program. The most recent decommissioning cost study was completed in 2012. In it, the estimated cost of decommissioning and disposal of low-level radioactive waste for the Cook Plant ranged from $1.3 billion to $1.7 billion in 2012 non-discounted dollars. As of December 31, 2012, the total decommissioning trust fund balance for the Cook Plant was approximately $1.4 billion. The balance of funds available to decommission Cook Plant will differ based on contributions and investment returns. The ultimate cost of retiring the Cook Plant may be materially different from estimates and funding targets as a result of the:

- Type of decommissioning plan selected.
- Escalation of various cost elements (including, but not limited to, general inflation and the cost of energy).
- Further development of regulatory requirements governing decommissioning.
- Technology available at the time of decommissioning differing significantly from that assumed in studies.
- Availability of nuclear waste disposal facilities.
- Availability of a United States Department of Energy facility for permanent storage of spent nuclear fuel.

Accordingly, management is unable to provide assurance that the ultimate cost of decommissioning the Cook Plant will not be significantly different than current projections. We will seek recovery from customers through our regulated rates if actual decommissioning costs exceed our projections. See Note 5 to the consolidated financial statements, entitled Commitments, Guarantees and Contingencies under the heading Nuclear Contingencies, included in the 2012 Annual Reports, for information with respect to nuclear waste and decommissioning.

Low-Level Radioactive Waste

The Low-Level Waste Policy Act of 1980 mandates that the responsibility for the disposal of low-level radioactive waste rests with the individual states. Low-level radioactive waste consists largely of ordinary refuse and other items that have come in contact with radioactive materials. Michigan does not currently have a disposal site for such waste available. I&M cannot predict when such a site may be available. However the states of Utah and Texas have licensed low level radioactive waste disposal sites which currently accept low level radioactive waste from Michigan waste generators. There is currently no set date limiting I&M's access to either of these facilities. The Cook Plant has a facility onsite designed specifically for the storage of low level radioactive waste. In the event that low level radioactive waste disposal facility access becomes unavailable, then low level radioactive waste can be stored onsite at this facility.

Structured Arrangements Involving Capacity, Energy and Ancillary Services

In January 2000, OPCo and National Power Cooperatives (NPC), an affiliate of Buckeye, entered into an agreement relating to the construction and operation of a 510 MW gas-fired electric generating peaking facility to be owned by NPC, called the Mone Plant. The Mone Plant began operations in 2002. OPCo is entitled to 100% of the power generated by the Mone Plant, and is responsible for the fuel and other costs of the facility through May 2014. Following that, NPC and OPCo will be entitled to 80% and 20%, respectively, of the power of the Mone Plant, and both parties will generally be responsible for their allocable portion of the fuel and other costs of the facility.

Certain Power Agreements

I&M

The Unit Power Agreement between AEGCo and I&M, dated March 31, 1982, provides for the sale by AEGCo to I&M of all the capacity (and the energy associated therewith) available to AEGCo at the Rockport Plant. Whether or not power is available from AEGCo, I&M is obligated to pay a demand charge for the right to receive such power (and an energy charge for any associated energy taken by I&M). The agreement will continue in effect until the last of the lease terms of Unit 2 of the Rockport Plant has expired (currently December 2022) unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo, and a unit power agreement between KPCo and AEGCo, AEGCo sells KPCo 30% of the capacity (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo the amounts that I&M would have paid AEGCo under the terms of the Unit Power Agreement between AEGCo and I&M for such entitlement. The KPCo unit power agreement expires in December 2022.

OPCo

The Unit Power Agreement between AEGCo and OPCo dated March 15, 2007, provides for the sale by AEGCo to OPCo of all the capacity and associated unit contingent energy and ancillary services available to OPCo from the Lawrenceburg Plant, a 1,146 MW gas-fired unit owned by AEGCo. OPCo is obligated to pay a capacity charge (whether or not power is available from the Lawrenceburg Plant), and the fuel, operating and maintenance charges associated with the energy dispatched by OPCo, and to reimburse AEGCo for other costs associated with the operation and ownership of the Lawrenceburg Plant. The agreement will continue in effect until December 31, 2017 unless extended as set forth in the agreement.

OVEC

AEP and several nonaffiliated utility companies jointly own OVEC. The aggregate equity participation of AEP in OVEC is 43.47%. Until 2001, OVEC supplied from its generating capacity the power requirements of a uranium enrichment plant near Portsmouth, Ohio owned by the United States Department of Energy. The sponsoring companies are entitled to receive and are obligated to pay for all OVEC capacity (approximately 2,200 MW) in proportion to their respective power participation ratios. The aggregate power participation ratio of APCo, I&M and OPCo is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and to provide a return on its equity capital. The Inter-Company Power Agreement, which defines the rights of the owners and sets the power participation ratio of each, was extended by the owners in 2011 from the termination date of March 2026 until June 2040. AEP and the other owners have authorized environmental investments related to their ownership interests. OVEC's Board of Directors has authorized capital expenditures totaling $1.4 billion in connection with the engineering and construction of flue gas desulfurization projects and the associated scrubber waste disposal landfills at its two generating plants. OVEC has completed the financing of the $1.4 billion required for these projects through debt issuances, including tax-advantaged debt issuances. One OVEC generating plant is operating with the new environmental controls, with the second scheduled to be operational with the new environmental controls during the second quarter of 2013.

ELECTRIC TRANSMISSION AND DISTRIBUTION

General

Other than AEGCo, AEP's public utility subsidiaries own and operate transmission and distribution lines and other facilities to deliver electric power. See Item 2 – Properties for more information regarding the transmission and distribution lines. Most of the transmission and distribution services are sold to retail customers of AEP's public utility subsidiaries in their service territories. These sales are made at rates approved by the state utility commissions of the states in which they operate, and in some instances, approved by the FERC. See Item 1 – Utility Operations – Regulation – Rates. The FERC regulates and approves the rates for wholesale transmission transactions. See Item 1 – Utility Operations – Regulation – FERC. As discussed below, some transmission services also are separately sold to non-affiliated companies.

Other than AEGCo, AEP's public utility subsidiaries hold franchises or other rights to provide electric service in various municipalities and regions in their service areas. In some cases, these franchises provide the utility with the exclusive right to provide electric service. These franchises have varying provisions and expiration dates. In general, the operating companies consider their franchises to be adequate for the conduct of their business. For a discussion of competition in the sale of power, see Item 1 – Utility Operations – Competition.

The use and the recovery of costs associated with the transmission assets of the AEP East Companies, including WPCo and KGPCo, are subject to the rules, protocols and agreements in place with PJM and as approved by the FERC.

Transmission Coordination Agreement, OATT, and ERCOT Protocols

PSO, SWEPCo and AEPSC are parties to the TCA. Under the TCA, a coordinating committee is charged with the responsibility of (a) overseeing the coordinated planning of the transmission facilities of the parties to the agreement, including the performance of transmission planning studies, (b) the interaction of such subsidiaries with independent system operators and other regional bodies interested in transmission planning and (c) compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such tariff. Pursuant to the TCA, AEPSC has responsibility for monitoring the reliability of their transmission systems and administering the OATT on behalf of the other parties to the agreement. The TCA also provides for the allocation among the parties of revenues collected for transmission and ancillary services provided under the OATT. These allocations have been determined by the FERC-approved OATT for the SPP (with respect to PSO and SWEPCo) and PUCT-approved protocols for ERCOT (with respect to TCC and TNC).

The following table shows the net (credits) or charges allocated pursuant to the TCA, SPP OATT and ERCOT protocols as described above for the years ended December 31, 2012, 2011 and 2010:

	Years Ended December 31,		
	2012	2011	2010
		(in thousands)	
PSO	$ 12,300	$ 9,000	$ 10,500
SWEPCo	(12,300)	(9,000)	(10,500)
TCC	2,100	2,100	2,100
TNC	(2,100)	(2,100)	(2,100)

Transmission Services for Non-Affiliates

In addition to providing transmission services in connection with their own power sales, AEP's public utility subsidiaries through RTOs also provide transmission services for non-affiliated companies. See Item 1 – Utility Operations – Electric Transmission and Distribution – Regional Transmission Organizations, below. Transmission of electric power by AEP's public utility subsidiaries is regulated by the FERC.

Coordination of East and West Zone Transmission

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 and AEP West Companies. The System Transmission Integration Agreement functions as an umbrella agreement in addition to the TA and the TCA. AEP's 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 System dispatch costs.

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

Regional Transmission Organizations

The AEP East Companies are members of PJM, and SWEPCo and PSO are members of the SPP (both FERC-approved RTOs). RTOs operate, plan and control utility transmission assets in a manner designed to provide open access to such assets in a way that prevents discrimination between participants owning transmission assets and those that do not. The remaining AEP West Companies (TCC and TNC) are members of ERCOT.

REGULATION

General

Except for transmission and/or retail generation sales in certain of its jurisdictions, AEP's public utility subsidiaries' retail rates and certain other matters are subject to traditional cost-based regulation by the state utility commissions. AEP's public utility subsidiaries are also subject to regulation by the FERC under the Federal Power Act with respect to wholesale power and transmission service transactions as well as certain unbundled retail transmission rates mainly in Ohio. I&M is subject to regulation by the NRC under the Atomic Energy Act of 1954, as amended, with respect to the operation of the Cook Plant. AEP and its public utility subsidiaries are also subject to the regulatory provisions of EPACT, much of which is administered by the FERC. EPACT provides the FERC increased utility merger oversight.

Rates

Historically, state utility commissions have established electric service rates on a cost-of-service basis, which is designed to allow a utility an opportunity to recover its cost of providing service and to earn a reasonable return on its investment used in providing that service. A utility's cost of service generally reflects its operating expenses, including operation and maintenance expense, depreciation expense and taxes. State utility commissions periodically adjust rates pursuant to a review of (a) a utility's adjusted revenues and expenses during a defined test period and (b) such utility's level of investment. Absent a legal limitation, such as a law limiting the frequency of rate changes or capping rates for a period of time, a state utility commission can review and change rates on its own initiative. Some states may initiate reviews at the request of a utility, customer, governmental or other representative of a group of customers. Such parties may, however, agree with one another not to request reviews of or changes to rates for a specified period of time.

Public utilities have traditionally financed capital investments until the new asset is placed in service. Provided the asset was found to be a prudent investment, it was then added to rate base and entitled to a return through rate recovery. Given long lead times in construction, the high costs of plant and equipment and volatile capital markets, we are actively pursuing strategies to accelerate rate recognition of investments and cash flow. AEP representatives continue to engage our state commissioners and legislators on alternative ratemaking options to reduce regulatory lag and enhance certainty in the process. These options include pre-approvals, a return on construction work in progress, rider/trackers, formula rates and the inclusion of future test-year projections into rates.

In many jurisdictions, the rates of AEP's public utility subsidiaries are generally based on the cost of providing traditional bundled electric service (i.e., generation, transmission and distribution service). In the ERCOT area of Texas, our utilities have exited the generation business and they currently charge unbundled cost-based rates for transmission and distribution service only. In Ohio, rates for electric service are unbundled for generation, transmission and distribution service. Historically, the state regulatory frameworks in the service area of the AEP System reflected specified fuel costs as part of bundled (or, more recently, unbundled) rates or incorporated fuel adjustment clauses in a utility's rates and tariffs. Fuel adjustment clauses permit periodic adjustments to fuel cost recovery from customers and therefore provide protection against exposure to fuel cost changes.

The following state-by-state analysis summarizes the regulatory environment of certain major jurisdictions in which AEP operates. Several public utility subsidiaries operate in more than one jurisdiction. See Note 3 to the consolidated financial statements, entitled Rate Matters, included in the 2012 Annual Reports, for more information regarding pending rate matters.

Indiana

I&M provides retail electric service in Indiana at bundled rates approved by the IURC, with rates set on a cost-of-service basis. Indiana provides for timely fuel and purchased power cost recovery through a fuel cost recovery mechanism.

Ohio

OPCo provides "default" retail electric service to customers at unbundled rates pursuant to the Ohio electric restructuring legislation. OPCo provides distribution and transmission services to retail customers within its service territory at cost-based rates approved by the PUCO or by the FERC. While Ohio transmission and distribution services continue to be established using more traditional cost-based methods, generation rates are currently priced using a hybrid approach that incorporates components of cost and market. We are seeking regulatory approval from the FERC to transfer the Ohio generation assets to a newly formed wholly owned competitive Ohio generation affiliate as of January 1, 2014. The recovery of those generation assets will be subject to market prices starting in mid-May 2015.

Oklahoma

PSO provides retail electric service in Oklahoma at bundled rates approved by the OCC. PSO's rates are set on a cost-of-service basis. Fuel and purchased energy costs above or below the amount included in base rates are recovered or refunded by applying fuel adjustment and other factors to retail kilowatt-hour sales. The factors are generally adjusted annually and are based upon forecasted fuel and purchased energy costs. Over or under collections of fuel and purchased energy costs for prior periods are returned to or recovered from customers in the year following when new annual factors are established.

Texas

Retail customers in TCC's and TNC's ERCOT service area of Texas are served through REPs. TCC and TNC provide transmission and distribution service on a cost-of-service basis at rates approved by the PUCT and wholesale transmission service under tariffs approved by the FERC consistent with PUCT rules. Effective September 2009, competition in the SPP area of Texas has been delayed until certain steps defined by statute and by PUCT rule have been accomplished. As such, the PUCT continues to approve base and fuel rates for SWEPCo's Texas operations on a cost of service basis.

Virginia

APCo currently provides retail electric service in Virginia at unbundled rates approved by the Virginia SCC. Virginia generally allows for timely recovery of fuel costs through a fuel adjustment clause. Transmission services are provided at OATT rates based on rates established by the FERC. In addition to base rates and fuel cost recovery, APCo is permitted to recover a variety of costs through rate adjustment clauses.

West Virginia

APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a cost-of-service basis. West Virginia generally allows for timely recovery of fuel costs through an expanded net energy cost which trues-up to actual expenses.

The following table illustrates certain regulatory information with respect to the states in which the public utility subsidiaries of AEP operate:

Jurisdiction	Percentage of AEP System Retail Revenues (a)	Percentage of OSS Profits Shared with Ratepayers	AEP Utility Subsidiaries Operating in that Jurisdiction	Authorized Return on Equity (b)
Ohio	29%	No sharing included in the ESP	OPCo	10.2% (c)
Texas	13%	Not applicable in ERCOT	TCC	9.96%
		Not applicable in ERCOT	TNC	9.96%
		90% in SPP	SWEPCo	10.33%
West Virginia	12%	100%	APCo	10.00%
		100%	WPCo	10.00%
Virginia	12%	75%	APCo	10.90%
Oklahoma	10%	75%	PSO	10.15%
Indiana	9%	50% below and above certain level (d)	I&M	10.20%
Louisiana	5%	50% to 100% (e)	SWEPCo	10.57%
Kentucky	4%	60% below and above certain level (f)	KPCo	10.50%
Arkansas	3%	50% to 100% (g)	SWEPCo	10.25%
Michigan	2%	80%	I&M	10.20%
Tennessee	1%	Not applicable	KGPCo	12.00%

(a) Represents the percentage of Utility Operations segment revenue from sales to retail customers to total Utility Operations segment revenue for the year ended December 31, 2012.

(b) Identifies the predominant authorized return on equity and may not include other, less significant, permitted recovery. Actual return on equity varies from authorized return on equity.

(c) OPCo's authorized return on equity for distribution rates is 10.2%. OPCo's generation revenues are governed by its Electric Security Plan (ESP) as approved by the PUCO.

(d) There is an annual $26.9 million credit established for off-system sales in base rates. If the off-system sales profits do not meet the level built into base rates, ratepayers reimburse I&M 50% of the shortfall. If the off-system sales profits exceed the level built into base rates, I&M reimburses ratepayers 50% of the excess.

(e) $874,000 and below, 100% is given to customers.
From $874,001 to $1,314,000, 85% is given to customers.
Above $1,314,000, 50% is given to customers.

(f) There is an annual $15.3 million credit established for off-system sales in base rates. If the monthly off-system sales profits do not meet the monthly level built into base rates, ratepayers reimburse KPCo 60% of the shortfall. If the monthly off-system sales profits exceed the monthly level built into base rates, KPCo reimburses ratepayers 60% of the excess.

(g) $758,600 and below, 100% is given to customers.
From $758,601 to $1,167,078, 85% is given to customers.
Above $1,167,078, 50% is given to customers.

FERC

Under the Federal Power Act, the FERC regulates rates for interstate power sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. The FERC regulations require AEP to provide open access transmission service at FERC-approved rates. The FERC also regulates unbundled transmission service to retail customers. The FERC also regulates the sale of power for resale in interstate commerce by (a) approving contracts for wholesale sales to municipal and cooperative utilities and (b) granting authority to public utilities to sell power at wholesale at market-based rates upon a showing that the seller lacks the ability to improperly influence market prices. Except for wholesale power that AEP delivers within its balancing area of the SPP, AEP has market-rate authority from the FERC, under which much of its wholesale marketing activity takes place. The FERC requires each public utility that owns or controls interstate transmission facilities to, directly or through an RTO, file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The FERC also requires all transmitting utilities, directly or through an RTO, to establish an Open Access Same-time Information System, which electronically posts transmission information such as available capacity and prices, and requires utilities to comply with Standards of Conduct that prohibit utilities' transmission employees from providing non-public transmission information to the utility's marketing employees.

The FERC oversees RTOs, entities created to operate, plan and control utility transmission assets. Order 2000 also prescribes certain characteristics and functions of acceptable RTO proposals. The AEP East Companies are members of PJM. SWEPCo and PSO are members of SPP.

The FERC has jurisdiction over the issuances of securities of most of our public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. In addition, both the FERC and state regulators are permitted to review the books and records of any company within a holding company system. EPACT gives the FERC increased utility merger oversight.

Competition

Under current Ohio law, electric generation is sold in a competitive market in Ohio and native load customers in Ohio have the ability to switch to alternative suppliers for their electric generation service. CRES providers are targeting retail customers by offering alternative generation service. In 2011, based upon an average annual load, approximately 10% of our Ohio load had switched to CRES providers. As of December 31, 2012, that amount had increased to 51%.

The public utility subsidiaries of AEP, like the electric industry generally, face competition in the sale of available power on a wholesale basis, primarily to other public utilities and power marketers. The Energy Policy Act of 1992 was designed, among other things, to foster competition in the wholesale market by creating a generation market with fewer barriers to entry and mandating that all generators have equal access to transmission services. As a result, there are more generators able to participate in this market. The principal factors in competing for wholesale sales are price (including fuel costs), availability of capacity and power and reliability of service.

AEP's public utility subsidiaries also compete with self-generation and with distributors of other energy sources, such as natural gas, fuel oil and coal, within their service areas. The primary factors in such competition are price, reliability of service and the capability of customers to utilize sources of energy other than electric power. With respect to competing generators and self-generation, the public utility subsidiaries of AEP believe that they generally maintain a favorable competitive position. With respect to alternative sources of energy, the public utility subsidiaries of AEP believe that the reliability of their service and the limited ability of customers to substitute other cost-effective sources for electric power place them in a favorable competitive position, even though their prices may be higher than the costs of some other sources of energy.

Significant changes in the global economy have led to increased price competition for industrial customers in the United States, including those served by the AEP System. Some of these industrial customers have requested price reductions from their suppliers of electric power. In addition, industrial customers that are downsizing or reorganizing often close a facility based upon its costs, which may include, among other things, the cost of electric power. The public utility subsidiaries of AEP cooperate with such customers to meet their business needs through, for example, providing various off-peak or interruptible supply options pursuant to tariffs filed with, and approved by, the various state commissions. Occasionally, these rates are negotiated with the customer, and then filed with the state commissions for approval.

Seasonality

The sale of electric power is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. The pattern of this fluctuation may change due to the nature and location of AEP's facilities and the terms of power sale contracts into which AEP enters. In addition, AEP has historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish AEP's results of operations and may impact its financial condition. Conversely, unusually extreme weather conditions could increase AEP's results of operations.

TRANSMISSION OPERATIONS

AEPTCo Overview

AEPTCo, a subsidiary of AEP, is a holding company for seven FERC-regulated transmission-only electric utilities, each of which is geographically aligned with our existing utility operating companies. AEPTCo is an indirect wholly-owned subsidiary of AEP. AEPTCo's seven wholly-owned transmission-only public utility companies (Transcos) are:

AEP East Transmission Companies (all operating within PJM)

- AEP Appalachian Transmission Company, Inc. (APTCo) (covering Virginia)
- AEP Indiana Michigan Transmission Company, Inc. (IMTCo)
- AEP Kentucky Transmission Company, Inc. (KTCo)
- AEP Ohio Transmission Company, Inc. (OHTCo)
- AEP West Virginia Transmission Company, Inc. (WVTCo)

AEP West Transmission Companies (all operating within SPP)

- AEP Oklahoma Transmission Company, Inc. (OKTCo)
- AEP Southwestern Transmission Company, Inc. (SWTCo) (covering Arkansas and Louisiana)

The Transcos develop, own and operate transmission assets that are physically connected to AEP's existing system. They are regulated for rate-making purposes exclusively by the FERC and employ a forward-looking formula rate tariff design. The Transcos are independent of but overlay AEP's existing vertically-integrated utility operating companies. IMTCo, OHTCo, OKTCo and WVTCo have received all necessary approvals for formation. IMTCo, OHTCo and OKTCo currently own and operate transmission assets. APTCo has received approval from the Virginia SCC, although the approval requires APTCo to request project-by-project approval from the Virginia SCC. Applications for regulatory approvals have been filed for the remaining Transcos and are currently under consideration in Arkansas, Kentucky and Louisiana. As of December 31, 2012, AEPTCo had $378 million of transmission assets in-service with plans to construct nearly $1.9 billion of additional transmission assets through 2015.

Capital Investment Strategy

All of the Transcos' capital needs are provided by Parent, AEPTCo and/or the AEP Utility Money Pool. The Utility Money Pool is used to meet the short-term borrowing needs of AEP regulated utility subsidiaries. The Utility Money Pool operates in accordance with the terms and conditions approved in regulatory orders. We forecast approximately $700 million, excluding AFUDC, of construction expenditures in 2013 for the Transcos.

In October 2012, AEPTCo completed a $250 million debt offering and immediately loaned $200 million and $50 million in proceeds to OHTCo and IMTCo, respectively. In December 2012, AEPTCo issued an additional $75 million in debt and immediately loaned the proceeds to OKTCo. APTCo will issue an additional $25 million in March 2013 but it is not yet determined which subsidiaries of AEPTCo will receive the proceeds.

Transmission development through the Transcos is primarily driven by

- Improvements to local area reliability by upgrading, rebuilding or replacing existing, aging infrastructure.
- Construction of new facilities to support both customer points of delivery and generation interconnections and new facilities required to maintain grid reliability associated with generation resource retirements.
- Projects assigned as a result of the regional planning initiatives conducted by PJM and SPP. PJM and SPP identify the need for transmission in support of regional reliability, congestion reduction and the integration of supply-side resources (primarily renewable) and retirements of generation facilities.

Regulatory Environment

The Transcos establish transmission rates annually through forward looking formula rate filings with the FERC pursuant to the FERC-approved formula rate implementation protocols. FERC has a formal review process in place to ensure updated transmission rates are prudently incurred and reasonably calculated. The annual updates are submitted to PJM and SPP, respectively, for public posting on their respective websites and submitted to FERC in an informational filing. Any interested party may participate in the review of the annual update and must comply with defined timelines to request additional information on such rate updates.

An OATT is the FERC rate schedule that provides the terms and conditions for transmission and related services on a transmission provider's transmission system (for the Transcos, PJM or SPP). FERC requires transmission providers to offer transmission service to all eligible customers (i.e., load-serving entities, power marketers, generators, and customers in states with supplier choice) on a non-discriminatory basis. The PJM and SPP OATTs provide standard terms and conditions to ensure consistent service availability and treatment of all transmission customers.

The Transcos' rates are included in the respective OATT for PJM and SPP. PJM and SPP collect the Transcos' rates from transmission customers taking service under the PJM and SPP OATTs, based on the terms and conditions in the respective OATTs for the service taken. Some charges are directly assigned to a transmission customer, but the majority of the charges are paid by transmission customers taking transmission service to serve load, deliver power, or to connect generation resources.

The FERC establishes transmission service rates for transmission owners (including the Transcos), as derived from their annual transmission revenue requirement (ATRR). Each of the Transcos' ATRR establishes rates for a one-year period based on the current projects in-service and proposed projects for a defined timeframe. The ATRR also includes a true-up calculation during the annual formula update for the previous year's billings, eliminating any potential for over- or under-recovery of the allowed return on and of the plant in-service. The Transcos collectively filed rate base increases of $283 million and $104 million for 2012 and 2011, respectively. The total transmission revenue requirement filed in the ATRR for 2012 and 2011 equaled $35 million and $13 million, respectively.

The cost of service formula rate mechanism allows for a return on equity of 11.49% based on a capital structure of up to 50% equity for the AEP East Transmission Companies. The AEP West Transmission Companies are allowed a return on equity of 11.20% based on a capital structure of up to 50% equity. The authorized returns on equity for the Transcos are commensurate with the FERC-authorized returns on equity in the PJM and SPP OATTs, respectively, for AEP's utility subsidiaries.

Joint Venture Initiatives

AEP has established joint ventures with other electric utility companies for the purpose of developing, building, and owning Extra High Voltage (EHV) transmission lines that seek to improve reliability and market efficiency and provide transmission access to remote generation sources in North America. Our joint ventures are at various stages of regulatory and RTO approval.

ETT, our largest joint venture, was established with MidAmerican Energy Holdings Company (MidAmerican) to construct, fund, own and operate electric transmission assets within ERCOT, including transmission projects in the Competitive Renewable Energy Zone (CREZ). The PUCT has awarded approximately $1.5 billion of total CREZ investment to ETT. AEP has a 50% ownership interest in ETT.

Electric Transmission America (ETA) is a joint venture between AEP and MidAmerican to build and own electric transmission assets. Prairie Wind Transmission, a joint venture between ETA and Westar Energy, began construction of a Kansas EHV transmission project in 2012. The approximately $180 million project is expected to be in service by the end of 2014. AEP has a 50% ownership interest in ETA and a 25% interest in Prairie Wind through its ownership interest in ETA.

Pioneer Transmission, LLC (Pioneer) is a joint venture between AEP and Duke Energy. AEP has a 50% ownership interest in Pioneer. The first segment of Pioneer's proposed line linking Duke Energy's Greentown Station to AEP's Rockport Station was included in the 2011 MISO Transmission Expansion Plan as a Multi-Value Project (MVP). Subject to regulatory approval, Pioneer has agreed to jointly develop the first segment with Northern Indiana Public Service Company as part of the settlement of a dispute regarding the rights to develop the project. The remaining portion of the project will be evaluated by MISO and PJM as part of their next planning review cycles. The estimated cost to complete the entire Pioneer project is $950 million.

RITELine Transmission Development, LLC (RTD) is a joint venture between AEP and Exelon. AEP owns 50% of RTD. RITELine Indiana, LLC (RITELine IN) is a joint venture between AEP and RTD. AEP, directly and indirectly through RTD, has an 87.5% ownership interest in RITELine IN. RITELine Illinois, LLC (RITELine IL) is a joint venture between RTD and Commonwealth Edison. Through its ownership interest in RTD, AEP has a 12.5% interest in RITELine IL. The RITELine project companies will build and operate approximately 420 miles of high-voltage transmission lines and related facilities in Indiana (with a projected cost of $400 million) and Illinois (with a projected cost of $1.2 billion). RTD received an order from the FERC in October 2011 granting incentives for the RITELine IN and RITELine IL projects. The projects are currently under evaluation by PJM.

Transource Energy, LLC (Transource), a joint venture between AEP and Great Plains Energy, was formed in 2012 primarily to pursue competitive transmission projects in the PJM, SPP and MISO transmission regions. Its first two projects are the Iatan-Nashua Project and the Sibley-Nebraska City Project, which were approved by the SPP in 2009 and 2010, respectively. AEP has an 86.5% ownership interest, and Great Plains Energy Incorporated holds a minority ownership interest, in Transource.

Business services for the joint ventures are provided by AEPSC and other AEP subsidiaries and the joint venture partners. Therefore, the joint ventures do not have any employees. For the equity investments within our Transmission Operations segment, we forecast approximately $55 million of AEP equity contributions in 2013 to support construction expenditures and the payment of operating expenses.

AEP RIVER OPERATIONS

Our AEP River Operations segment transports coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi rivers. Almost all of our customers are nonaffiliated third parties who obtain the transport of coal and dry bulk commodities for various uses. We charge these customers market rates for the purpose of making a profit. Depending on market conditions and other factors, including barge availability, we permit AEP utility subsidiary affiliates to use certain of our equipment at rates that reflect our cost. Our affiliated utility customers procure the transport of coal for use as fuel in their respective generating plants. AEP River Operations includes approximately 2,500 barges, 45 towboats and 25 harbor boats that we own or lease. These assets are separate from the barges and towboats dedicated exclusively to transporting coal for use as fuel in our own generating facilities discussed under the prior segment. See Item 1 – Utility Operations – Electric Generation – Fuel Supply – Coal and Lignite.

Competition within the barging industry for major commodity contracts is intense, with a number of companies offering transportation services in the waterways we serve. We compete with other carriers primarily on the basis of commodity shipping rates, but also with respect to customer service, available routes, value-added services (including scheduling convenience and flexibility). The industry continues to experience consolidation. The resulting companies increasingly offer the widespread geographic reach necessary to support major national customers. Demand for barging services can be seasonal, particularly with respect to the movement of harvested agricultural commodities (beginning in the late summer and extending through the fall). Cold winter weather, water levels and inefficient older river locks operated by others may also limit our operations when certain of the waterways we serve are closed or commercial traffic is limited.

Our transportation operations are subject to regulation by the U.S. Coast Guard, federal laws, state laws and certain international conventions. Legislation has been proposed that could make our towboats subject to inspection by the U.S. Coast Guard.

GENERATION AND MARKETING

Our Generation and Marketing Segment consists of nonutility generating assets, a wholesale energy trading and marketing business and a retail supply and energy management business. With respect to our wholesale energy trading and marketing business, we enter into short and long-term transactions to buy or sell capacity, energy and ancillary services primarily in ERCOT, PJM and MISO. As of December 31, 2012, the assets utilized in this segment included approximately 310 MW of company-owned domestic wind power facilities, 177 MW of domestic wind power from long-term purchase power agreements and 377 MW of coal-fired capacity which was obtained through an agreement effective through 2027 that transfers TNC's interest in the Oklaunion power station to AEP Energy Partners, Inc. The power obtained from the Oklaunion power station is marketed and sold in ERCOT. We are regulated by the PUCT for transactions inside ERCOT and by the FERC for transactions outside of ERCOT. While peak load in ERCOT typically occurs in the summer, we do not necessarily expect seasonal variation in our operations. With respect to our retail supply and energy management business, AEP Energy is a retail electricity supplier that supplies electricity to residential, commercial, and industrial customers. AEP Energy provides an array of energy solutions and is operating in Illinois, Pennsylvania, Delaware, Maryland, New Jersey, Ohio and Washington, D.C. AEP Energy also provides energy demand-side management solutions nationwide. AEP Energy had more than 160,000 customer accounts as of December 31, 2012.

EXECUTIVE OFFICERS OF AEP as of February 26, 2013

The following persons are executive officers of AEP. Their ages are given as of February 1, 2013. The officers are appointed annually for a one-year term by the board of directors of AEP.

Nicholas K. Akins
President and Chief Executive Officer
Age 52
Chief Executive Officer since November 2011 and President since January 2011. Was Executive Vice President-Generation from September 2006 to December 2010.

Lisa M. Barton
Executive Vice President – Transmission
Age 47
Executive Vice President-Transmission of AEPSC since August 2011. Was Senior Vice President-Transmission Strategy and Business Development of AEPSC from November 2010 to July 2011, Vice President-Transmission Strategy and Business Development of AEPSC from October 2007 to November 2010.

David M. Feinberg
Executive Vice President, General Counsel and Secretary
Age 43
Executive Vice President since January 2013. Was Senior Vice President, General Counsel and Secretary from January 2012 to December 2012 and Senior Vice President and General Counsel of AEPSC from May 2011 to December 2011. Previously served as Vice President, General Counsel and Secretary of Allegheny Energy, Inc. from 2006 to 2011.

Lana L. Hillebrand
Senior Vice President and Chief Administrative Officer
Age 52
Senior Vice President and Chief Administrative Officer since December 2012. Previously served as South Region leader-Senior Partner at Aon Hewitt since 2010. Was U.S. Consulting Client Development leader-managing principal at Aon Hewitt from 2008-2010.

Mark C. McCullough
Executive Vice President – Generation
Age 53
Executive Vice President-Generation of AEPSC since January 2011. Was Senior Vice President-Fossil & Hydro Generation of AEPSC from February 2008 to December 2010 and Vice President-Baseload Generation of AEPSC from June 2005 to February 2008.

Robert P. Powers
Executive Vice President and Chief Operating Officer
Age 58
Executive Vice President and Chief Operating Officer since November 2011. Was President-Utility Group from April 2009 to November 2011, President-AEP Utilities from January 2008 to April 2009.

Brian X. Tierney
Executive Vice President and Chief Financial Officer
Age 45
Executive Vice President and Chief Financial Officer since October 2009. Was Executive Vice President-AEP Utilities East of AEPSC from January 2008 to October 2009.

Dennis E. Welch
Executive Vice President and Chief External Officer
Age 61
Executive Vice President and Chief External Officer since January 2013. Was Executive Vice President and Chief Administrative Officer from October 2011 to December 2012. Was Executive Vice President-Environment, Safety & Health and Facilities from January 2008 to September 2011.

ITEM 1A. RISK FACTORS

GENERAL RISKS OF OUR REGULATED OPERATIONS

We may not be able to recover the costs of our substantial planned investment in capital improvements and additions. – Affecting each Registrant

Our business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades and retrofits, construction of additional transmission facilities, modernizing existing infrastructure as well as other initiatives. Our public utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. If these regulatory commissions do not approve adjustments to the rates we charge, we would not be able to recover the costs associated with our planned extensive investment. This would cause our financial results to be diminished. While we may seek to limit the impact of any denied recovery by attempting to reduce the scope of our capital investment, there can be no assurance as to the effectiveness of any such mitigation efforts, particularly with respect to previously incurred costs and commitments.

Approval of the new ESP order in Ohio may be overturned. – Affecting AEP and OPCo

In August 2012, the PUCO issued an order which adopted and modified a new ESP through May 2015. The ESP allowed the continuation of the fuel adjustment clause and established a non-bypassable Distribution Investment Rider effective September 2012 through May 2015 to recover, with certain caps, post-August 2010 distribution investment. The ESP also maintained recovery of several previous ESP riders and approved a storm damage recovery mechanism which allowed OPCo to defer the majority of the incremental distribution operation and maintenance costs from 2012 storms. In January 2013, the PUCO issued its Order on Rehearing for the ESP which generally upheld its August 2012 order. The PUCO addressed certain issues around the energy auctions while other SSO issues were deferred to a separate docket. Comments on the rehearing order are permitted to be filed by intervenors through March 2013. If the PUCO reverses all or part of the ESP rehearing order, it could reduce future net income and cash flows and impact financial condition.

We may not fully collect deferred capacity costs. – Affecting AEP and OPCo

The PUCO adopted and modified the new ESP and established a non-bypassable Retail Stability Rider (RSR). A portion of the RSR provides for the collection of deferred capacity costs. The deferred capacity costs may exceed the amount we will collect under the RSR. In addition, the Industrial Energy Users-Ohio filed a claim before the Supreme Court of Ohio stating, among other things, that OPCo's recovery of its capacity costs is illegal. If OPCo is ultimately not permitted to fully collect its deferred capacity costs, it would reduce future net income and cash flows and impact financial condition.

We may not recover deferred fuel costs. – Affecting AEP and OPCo

In August 2012, the PUCO ordered recovery of deferred fuel costs beginning September 2012 through the Phase-In Recovery Rider. The August 2012 order was upheld by the PUCO in October 2012. OPCo and intervenors have filed appeals at the Supreme Court of Ohio. If the Supreme Court of Ohio does not permit full recovery of OPCo's deferred fuel costs, it would reduce future net income and cash flows and impact financial condition.

Prior ESP rate recovery approved in Ohio may have to be returned, may not provide full recovery of costs and is subject to appeal. – Affecting AEP and OPCo

The PUCO issued an order in March 2009 that modified and approved the prior ESP which established rates through 2011. The prior ESP order generally authorized rate increases during the ESP period, subject to caps that limited the rate increases, and also provided a fuel adjustment clause for the three-year period of that ESP. There remain three risks associated with this prior approved recovery: (a) amounts collected by us for the years 2010 and 2011 are subject to an excessive earnings test administered by the PUCO, which could require us to refund amounts to customers, (b) the recovery under the fuel adjustment clause includes significant deferrals of costs associated with an interim arrangement with a major steel producing customer and is subject to the PUCO's ultimate decision regarding those deferrals plus related carrying charges, and (c) intervenors are challenging various issues at the Supreme Court of Ohio, asserting that charges that the PUCO reversed going forward also should have been reversed retrospectively and challenging various aspects of approved environmental carrying charges. If the PUCO and/or the Supreme Court of Ohio reverses all or part of the rate recovery or if deferred amounts are not recovered for other reasons, it could reduce future net income and cash flows and impact financial condition.

Ohio may require us to refund additional fuel costs. – Affecting AEP and OPCo

In January 2012, the PUCO ordered that proceeds from a 2008 coal contract settlement agreement be applied against OPCo's under-recovered fuel balance and that an outside consultant be hired to review our fuel procurement through 2011. The audit by the outside consultant included recommendations that would limit some of our fuel recovery or require us to refund certain fuel costs already incurred. In addition, an intervenor filed a claim for refund of certain fuel costs with the Supreme Court of Ohio. If the PUCO orders result in a reduction to our fuel recovery and/or the Supreme Court of Ohio ultimately determines to grant all or part of the requested refund, it could reduce future net income and cash flows and impact financial condition.

We may not fully recover all of the investment in and expenses related to the Turk Plant – Affecting AEP and SWEPCo

In December 2012, SWEPCo placed the Turk Plant in Arkansas into commercial operation. SWEPCo holds a 73% ownership interest in the 600 MW coal-fired generating facility. SWEPCo had originally intended that 88 MW of the Turk Plant would become part of the rate base for its retail customers in Arkansas. Following a proceeding at the Arkansas Supreme Court, the APSC issued an order which reversed and set aside a previously granted Certificate of Environmental Compatibility and Public Need. This portion of the Turk Plant output is currently not subject to cost based rate recovery and is being sold into the SPP market. SWEPCo has included a request to recover a portion of the costs of the Turk Plant in its base rate case filed in Texas and has made a formula rate filing with the LPSC, and a subsequent settlement seeking recovery for a portion of the costs of the Turk Plant. If SWEPCo cannot recover all of its investment and expenses related to the Turk Plant either through retail rates or sales into the SPP market, it could reduce future net income and cash flows and impact financial condition.

We may not fully recover all of the investment in and expenses related to extending the useful life of the Cook Plant – Affecting AEP and I&M

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects for Cook Plant Units 1 and 2 intended to ensure the safe and reliable operation of the plant through its licensed life. The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. As of December 31, 2012, I&M has incurred $176 million related to the LCM Project, including AFUDC. If I&M is not ultimately permitted to recover its LCM Project costs, it would reduce future net income and cash flows and impact financial condition.

Request for rate recovery in Texas may not be approved in its entirety. – Affecting AEP and SWEPCo

In July 2012, SWEPCo filed a request with the PUCT for an annual increase in Texas base rates. A portion of the increase seeks recovery for costs associated with the construction and operation of the Texas jurisdictional share (approximately 33%) of the Turk Plant. In April 2012, the Texas Industrial Energy Consumers filed a petition for review at the Supreme Court of Texas contending that the Turk Plant is unnecessary to serve retail customers. The Supreme Court of Texas has requested full briefing from the parties. If SWEPCo cannot recover all of its investment and expenses related to the Turk Plant, it would reduce future net income and cash flows and impact financial condition.

Our transmission investment strategy and execution bears certain risks associated with these activities. – Affecting AEP

We expect that a growing portion of our earnings in the future will derive from the transmission investments and activities of AEPTCo and our transmission joint ventures. FERC policy currently favors the expansion and updating of the transmission infrastructure within its jurisdiction. If FERC were to adopt a different policy or if transmission needs do not continue or develop as projected, our strategy of investing in transmission could be curtailed. We believe our experience with transmission facilities construction and operation gives us an advantage over other competitors in securing authorization to install, construct and operate new transmission lines and facilities.

However, there can be no assurance that PJM, SPP or other RTOs will authorize any new transmission projects or will award any such projects to us. If the FERC were to lower the rate of return it has authorized for our transmission investments and facilities, it could reduce future net income and cash flows and impact financial condition.

We may not recover costs incurred to begin construction on projects that are canceled. – Affecting each Registrant

Our business plan for the construction of new projects involves a number of risks, including construction delays, nonperformance by equipment and other third party suppliers, and increases in equipment and labor costs. To limit the risks of these construction projects, we enter into equipment purchase orders and construction contracts and incur engineering and design service costs in advance of receiving necessary regulatory approvals and/or siting or environmental permits. If any of these projects is canceled for any reason, including our failure to receive necessary regulatory approvals and/or siting or environmental permits, we could incur significant cancellation penalties under the equipment purchase orders and construction contracts. In addition, if we have recorded any construction work or investments as an asset we may need to impair that asset in the event the project is canceled.

Rate regulation may delay or deny full recovery of capital improvements, additions, storm damage operations and maintenance expense repairs and other costs. – Affecting each Registrant

Our public utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. These rates are generally regulated based on an analysis of the applicable utility's expenses incurred in a test year. Thus, commission-approved rates may or may not match a utility's expenses at any given time. There may also be a delay between the timing of when these costs are incurred and when these costs are recovered. Traditionally, we have financed capital investments and improvements until the new asset was placed in service. Provided the asset was found to be a prudent investment, the asset was then added to rate base and entitled to a return through rate recovery. Similarly, we often finance the operations and maintenance expense to repair facilities damaged by storms or other severe weather events until the operations and maintenance storm costs, including any deferred regulatory assets, are recovered in rates. Long lead times in construction and scheduled repairs, the high costs of plant and equipment and volatile capital markets have heightened the risks involved in our capital investments, repairs and improvements. While we are actively pursuing strategies to accelerate rate recognition of investments and cash flow, including pre-approvals, a return on construction work in progress, rider/trackers, formula rates and the inclusion of future test-year projections into rates, there can be no assurance that these will be adopted, that the applicable regulatory commission will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will be done in a timely manner.

Certain of our revenues and results of operations are subject to risks that are beyond our control. – Affecting each Registrant

Our operations are structured to comply with all applicable federal and state laws and regulations and we take measures to minimize the risk of significant disruptions. Material disruptions at one or more of our operational facilities, however, could negatively impact our revenues, operating and capital expenditures and results of operations. Such events may also create additional risks related to the supply and/or cost of equipment and materials. We could experience unexpected but significant interruption due to several events, including, but not limited to:

- Major facility or equipment failure.
- An environmental event such as a serious spill or release.
- Fires, floods, droughts, earthquakes, hurricanes, tornados or other natural disasters.
- Wars, terrorist acts (including cyber-terrorism) or threats and other catastrophic events.
- Significant health impairments or disease events.
- Other serious operational problems.

We are exposed to nuclear generation risk. – Affecting AEP and I&M

Through I&M, we own the Cook Plant. It consists of two nuclear generating units for a rated capacity of 2,191 MW, or about 6% of the generating capacity in the AEP System. We are, therefore, subject to the risks of nuclear generation, which include the following:

- The potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials such as spent nuclear fuel.
- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations.
- Uncertainties with respect to contingencies and assessment amounts triggered by a loss event (federal law requires owners of nuclear units to purchase the maximum available amount of nuclear liability insurance and potentially contribute to the losses of others).
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

There can be no assurance that I&M's preparations or risk mitigation measures will be adequate if and when these risks are triggered.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants such as ours. In addition, although we have no reason to anticipate a serious nuclear incident at our plants, if an incident did occur, it could harm our results of operations or financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit. Moreover, a major incident at any nuclear facility in the U.S. could require us to make material contributory payments.

Costs associated with the operation (including fuel), maintenance and retirement of nuclear plants continue to be more significant and less predictable than costs associated with other sources of generation, in large part due to changing regulatory requirements and safety standards, availability of nuclear waste disposal facilities and experience gained in the operation of nuclear facilities. Costs also may include replacement power, any unamortized investment at the end of the useful life of the Cook Plant (whether scheduled or premature), the carrying costs of that investment and retirement costs. Our ability to obtain adequate and timely recovery of costs associated with the Cook Plant is not assured.

The different regional power markets in which we compete or will compete in the future have changing market and transmission structures, which could affect our performance in these regions. – Affecting each Registrant

Our results are likely to be affected by differences in the market and transmission structures in various regional power markets. The rules governing the various regional power markets, including SPP and PJM, may also change from time to time which could affect our costs or revenues. Because the manner in which RTOs will evolve remains unclear, we are unable to assess fully the impact that changes in these power markets may have on our business.

We could be subject to higher costs and/or penalties related to mandatory reliability standards. – Affecting each Registrant

As a result of EPACT, owners and operators of the bulk power transmission system are subject to mandatory reliability standards promulgated by the North American Electric Reliability Corporation and enforced by the FERC. These standards, which previously were being applied on a voluntary basis, became mandatory in June 2007. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with new reliability standards may subject us to higher operating costs and/or increased capital expenditures. While we expect to recover costs and expenditures from customers through regulated rates, there can be no assurance that the applicable commissions will approve full recovery in a timely manner. If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties, which likely would not be recoverable from customers through regulated rates.

RISKS RELATED TO MARKET, ECONOMIC OR FINANCIAL VOLATILITY AND OTHER RISKS

Our financial performance may be adversely affected if we are unable to successfully operate our facilities or perform certain corporate functions. – Affecting each Registrant

Our performance is highly dependent on the successful operation of our generation, transmission and distribution facilities. Operating these facilities involves many risks, including:

- Operator error and breakdown or failure of equipment or processes.
- Operating limitations that may be imposed by environmental or other regulatory requirements.
- Labor disputes.
- Compliance with mandatory reliability standards, including mandatory cyber security standards.
- Information technology failure that impairs our information technology infrastructure or disrupts normal business operations.
- Information technology failure that affects our ability to access customer information or causes us to lose confidential or proprietary data that materially and adversely affects our reputation or exposes us to legal claims.
- Fuel or water supply interruptions caused by transportation constraints, adverse weather such as drought, non-performance by our suppliers and other factors.
- Catastrophic events such as fires, earthquakes, explosions, hurricanes, tornados, ice storms, terrorism (including cyber-terrorism), floods or other similar occurrences.

Hostile cyber intrusions could severely impair our operations, lead to the disclosure of confidential information and damage our reputation. – Affecting each Registrant

We own assets deemed as critical infrastructure, the operation of which is dependent on information technology systems. Further, the computer systems that run our facilities are not completely isolated from external networks. Parties that wish to disrupt the U.S. bulk power system or our operations could view our computer systems, software or networks as attractive targets for cyber attack. In addition, our business requires that we collect and maintain sensitive customer data, as well as confidential employee and shareholder information, which is subject to electronic theft or loss.

A successful cyber attack on the systems that control our generation, transmission, distribution or other assets could severely disrupt business operations, preventing us from serving customers or collecting revenues. The breach of certain business systems could affect our ability to correctly record, process and report financial information. A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to our reputation. In addition, the misappropriation, corruption or loss of personally identifiable information and other confidential data could lead to significant breach notification expenses and mitigation expenses such as credit monitoring. We maintain property and casualty insurance that may cover certain physical damage or third-party injuries caused by potential cybersecurity incidents. However, other damage and claims arising from such incidents may not be covered or may exceed the amount of any insurance available. For these reasons, a significant cyber incident could reduce future net income and cash flows and impact financial condition.

In an effort to reduce the likelihood and severity of cyber intrusions, we have a comprehensive cybersecurity program designed to protect and preserve the confidentiality, integrity and availability of data and systems. In addition, we are subject to mandatory cybersecurity regulatory requirements. However, cyber threats continue to evolve and adapt, and, as a result, there is a risk that we could experience a successful cyber attack despite our current security posture and regulatory compliance efforts.

If we are unable to access capital markets on reasonable terms, it could reduce future net income and cash flows and impact financial condition. – Affecting each Registrant

We rely on access to capital markets as a significant source of liquidity for capital requirements not satisfied by operating cash flows. Volatility and reduced liquidity in the financial markets could affect our ability to raise capital and fund our capital needs, including construction costs and refinancing maturing indebtedness. In addition, if capital is available only on less than reasonable terms or to borrowers whose creditworthiness is better than ours, capital costs could increase materially. Restricted access to capital markets and/or increased borrowing costs could reduce future net income and cash flows and impact financial condition.

Downgrades in our credit ratings could negatively affect our ability to access capital and/or to operate our power trading businesses. – Affecting each Registrant

The credit ratings agencies periodically review our capital structure and the quality and stability of our earnings. Any negative ratings actions could constrain the capital available to us and could limit our access to funding for our operations. Our business is capital intensive, and we are dependent upon our ability to access capital at rates and on terms we determine to be attractive. In periods of market turmoil, access to capital is difficult for all borrowers. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and could reduce future net income and cash flows and impact financial condition.

Our power trading business relies on the investment grade ratings of our individual public utility subsidiaries' senior unsecured long-term debt or on the investment grade ratings of AEP parent. Most of our counterparties require the creditworthiness of an investment grade entity to stand behind transactions. If those ratings were to decline below investment grade, our ability to operate our power trading business profitably would be diminished because we would likely have to deposit cash or cash-related instruments which would reduce our profits.

AEP has no income or cash flow apart from dividends paid or other obligations due it from its subsidiaries. – Affecting AEP

AEP is a holding company and has no operations of its own. Its ability to meet its financial obligations associated with its indebtedness and to pay dividends on its common stock is primarily dependent on the earnings and cash flows of its operating subsidiaries, primarily its regulated utilities, and the ability of its subsidiaries to pay dividends to, or repay loans from, AEP. Its subsidiaries are separate and distinct legal entities that have no obligation (apart from loans from AEP) to provide AEP with funds for its payment obligations, whether by dividends, distributions or other payments. Payments to AEP by its subsidiaries are also contingent upon their earnings and business considerations. In addition, any payment of dividends, distributions or advances by the utility subsidiaries to AEP could be subject to regulatory restrictions. AEP indebtedness and common stock dividends are structurally subordinated to all subsidiary indebtedness and preferred stock obligations, if any.

Our operating results may fluctuate on a seasonal or quarterly basis and with general economic and weather conditions. – Affecting each Registrant

Electric power generation is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, our overall operating results in the future may fluctuate substantially on a seasonal basis. The pattern of this fluctuation may change depending on the terms of power sale contracts that we enter into. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish our results of operations and harm our financial condition. Conversely, unusually extreme weather conditions could increase AEP's results of operations in a manner that would not likely be sustainable.

Further, deteriorating economic conditions generally result in reduced consumption by our customers, particularly industrial customers who may curtail operations or cease production entirely, while an expanding economic environment generally results in increased revenues. As a result, our overall operating results in the future may fluctuate on the basis of prevailing economic conditions.

Failure to attract and retain an appropriately qualified workforce could harm our results of operations. – Affecting each Registrant

Certain events, such as an aging workforce without appropriate replacements, mismatch of skillset or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect the ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be negatively affected.

Parties we have engaged to provide construction materials or services may fail to perform their obligations, which could harm our results of operations. – Affecting each Registrant

Our business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades, construction of additional generation units and transmission facilities as well as other initiatives. We are exposed to the risk of substantial price increases in the costs of materials used in construction. We have engaged numerous contractors and entered into a large number of agreements to acquire the necessary materials and/or obtain the required construction related services. As a result, we are also exposed to the risk that these contractors and other counterparties could breach their obligations to us. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices and almost certainly cause delays in that and related projects. Although our agreements are designed to mitigate the consequences of a potential default by the counterparty, our actual exposure may be greater than these mitigation provisions. This would cause our financial results to be diminished, and we might incur losses or delays in completing construction.

Changes in commodity prices and the costs of transport may increase our cost of producing power or decrease the amount we receive from selling power, harming our financial performance. – Affecting each Registrant

We are exposed to changes in the price and availability of coal and the price and availability to transport coal because most of our generating capacity is coal-fired. We have contracts of varying durations for the supply of coal for most of our existing generation capacity, but as these contracts end or otherwise are not honored, we may not be able to purchase coal on terms as favorable as the current contracts. Similarly, we are exposed to changes in the price and availability of emission allowances. We use emission allowances based on the amount of coal we use as fuel and the reductions achieved through emission controls and other measures. As long as current environmental programs remain in effect, we have sufficient emission allowances to cover the majority of our projected needs for the next two years and beyond. If the Federal EPA is able to create a replacement rule to reduce interstate transport, and it is acceptable by the courts, additional costs may be incurred either to acquire additional allowances or to achieve further reductions in emissions. If we need to obtain allowances under a replacement rule, those purchases may not be on as favorable terms as those under the current environmental programs. Our risks relative to the price and availability to transport coal include the volatility of the price of diesel which is the primary fuel used in transporting coal by barge.

We also own natural gas-fired facilities which exposes us to market prices of natural gas. Historically, natural gas prices have tended to be more volatile than prices for other fuel sources. Recently however, the availability of natural gas from shale production has lessened price volatility. Our ability to make off-system sales at a profit is highly dependent on the price of natural gas. As the price of natural gas falls, other market participants that utilize natural gas-fired generation will be able to offer electricity at increasingly competitive prices relative to our off-system sales prices, so the margins we realize from sales will be lower and, on occasion, we may need to curtail operation of marginal plants. We expect the availability of shale natural gas and issues related to its accessibility will have a long-term material effect on the price and volatility of natural gas.

Prices for coal, natural gas and emission allowances have shown material upward and downward swings in the past. Changes in the cost of coal, emission allowances or natural gas and changes in the relationship between such costs and the market prices of power will affect our financial results.

In addition, actual power prices and fuel costs will differ from those assumed in financial projections used to value our trading and marketing transactions, and those differences may be material. As a result, our financial results may be diminished in the future as those transactions are marked to market.

Our AEP River Operations business segment cannot operate if river levels are too low or too high. – Affecting AEP

Our AEP River Operations business segment transports coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi rivers. If drought conditions or other factors cause the water levels of one or more of these rivers to drop below the amount necessary to permit commercial barging traffic, it would prevent our AEP River Operations from transporting cargo on the affected river. Conversely, if unusually high amounts of precipitation or other factors cause the water levels of one or more of these rivers to be too high to permit commercial barging traffic, it would prevent our AEP River Operations from transporting cargo on the affected river. Extreme water levels that do not close river basin commercial traffic can still harm our business if the levels curtail the total volume permitted to move on the affected river. The levels on portions of the Mississippi River in 2013 have been reported as the lowest since the levels caused by severe drought in 1988. Any reduction in the commercial activities of our AEP River Operations due to low water levels could reduce future net income and cash flows.

RISKS RELATING TO STATE RESTRUCTURING

We are unable to fully predict the effects of corporate separation in Ohio and Ohio generation becoming subject to market forces. – Affecting AEP and OPCo

While Ohio rates for transmission and distribution services continue to be established using a more traditional cost-based method, in October 2012, the PUCO approved OPCo's corporate separation plan to transfer its generation assets to a new competitive, unregulated generation affiliate. During this transition, generation rates will be priced using a hybrid approach that incorporates components of cost and market. Starting in mid-2015, generation rates will be subject entirely to market prices. We have made additional filings at the FERC and other state commissions related to this corporate separation. If all regulatory approvals are received, our results of operations related to generation previously held by OPCo will be largely determined by the prevailing market conditions. We can give no assurance that the FERC will not impose material adverse terms as a condition to approving our corporate separation filings. Additionally, some of these generation units may no longer be cost effective and may be retired prior to the end of their anticipated useful life. This could result in material impairments.

We are unable to fully predict the effects of terminating the Interconnection Agreement. – Affecting AEP, APCo, I&M and OPCo

In October 2012, we submitted several filings with the FERC seeking approval to fully separate OPCo's generating assets from its distribution and transmission operations. The filings requested approval to transfer approximately 9,200 MW of OPCo-owned generation assets to a new competitive, unregulated generation affiliate. We also requested approval from the FERC and, as applicable, the KPSC, the Virginia SCC and the WVPSC to transfer 1,647 MW of OPCo-owned generation assets to APCo and 780 MW of OPCo-owned generation assets to KPCo. Additionally, we asked for FERC approval to terminate the existing Interconnection Agreement and to authorize a new Power Coordination Agreement among APCo, I&M and KPCo. A decision from the FERC is expected in mid-2013. Significant gaps could emerge if the Interconnection Agreement is terminated without approval of the generation asset transfers and/or the new Power Coordination Agreement. Surplus members would no longer automatically sell to deficit members, and they may not be able to otherwise sell that surplus in amounts or at rates equal to what they obtained under the Interconnection Agreement. Conversely, deficit members would no longer automatically purchase from surplus members, and they may not be able to otherwise purchase in amounts or at rates equal to what they obtained under the Interconnection Agreement. The possible loss of these sales by the surplus members and the potential increase in costs for the deficit members could reduce future net income and cash flows. In addition, we can give no assurance that the FERC or other state commissions will not impose material adverse terms as a condition to approving these arrangements and asset transfers.

Customers are choosing alternative electric generation service providers, as allowed by Ohio law and regulation. – Affecting AEP and OPCo

Under current Ohio law, electric generation is sold in a competitive market in Ohio and native load customers in Ohio have the ability to switch to alternative suppliers for their electric generation service. CRES providers are targeting retail customers by offering alternative generation service. As of December 31, 2012, based upon an average annual load, approximately 51% of our Ohio load had switched to CRES providers. These evolving market conditions will continue to impact our results of operations.

Collection of our revenues in Texas is concentrated in a limited number of REPs. – Affecting AEP

Our revenues from the distribution of electricity in the ERCOT area of Texas are collected from REPs that supply the electricity we distribute to their customers. Currently, we do business with approximately one hundred REPs. In 2012, TCC's largest REP accounted for 16% of its operating revenue and its second largest REP accounted for 7% of its operating revenue; TNC's largest REP accounted for 19% of its operating revenues and its second largest REP accounted for 12% of its operating revenues. Adverse economic conditions, structural problems in the Texas market or financial difficulties of one or more REPs could impair the ability of these REPs to pay for our services or could cause them to delay such payments. We depend on these REPs for timely remittance of payments. Any delay or default in payment could reduce future cash flows and impact financial condition.

RISKS RELATED TO OWNING AND OPERATING GENERATION ASSETS AND SELLING POWER

Our costs of compliance with existing environmental laws are significant. – Affecting each Registrant

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. Approximately 90% of the electricity generated by the AEP System is produced by the combustion of fossil fuels. Emissions of nitrogen and sulfur oxides, mercury and particulates from fossil fueled generating plants are subject to increased regulations, controls and mitigation expenses. Compliance with these legal requirements requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees and permits at all of our facilities and could cause us to retire generating capacity prior to the end of its estimated useful life. These expenditures have been significant in the past and we expect that they will continue to be significant in order to comply with the current and proposed regulations. Costs of compliance with environmental regulations could reduce future net income and impact financial condition, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated and the number and types of assets we operate increase. If we retire generating plants prior to the end of their estimated useful life, there can be no assurance that we will recover the remaining costs associated with such plants. While we expect to recover our expenditures for pollution control technologies, replacement generation and associated operating costs from customers through regulated rates (in regulated jurisdictions) or market prices, without such recovery those costs could reduce our future net income and cash flows and possibly harm our financial condition.

Regulation of CO_2 emissions, either through legislation or by the Federal EPA, could materially increase costs to us and our customers or cause some of our electric generating units to be uneconomical to operate or maintain. – Affecting each Registrant

The U.S. Congress has not taken any significant steps toward enacting legislation to control CO_2 emissions since 2009. In December 2009, the Federal EPA issued a final endangerment finding under the CAA regarding emissions from motor vehicles. The Federal EPA also finalized CO_2 emission standards for new motor vehicles, and issued a rule that implements a permitting program for new and modified stationary sources of CO_2 emissions in a phased manner through 2014. Several groups have filed challenges to the endangerment finding and the Federal EPA's subsequent rulemakings. In 2012, the Federal EPA issued a proposed CO_2 emissions standard for new power generation sources with a CO_2 limit equivalent to a natural gas unit. A final rule is expected in the first half of 2013. Management believes some policy approaches being discussed would have significant and widespread negative consequences for the national economy and major U.S. Industrial enterprises, including us and our customers.

If CO_2 and other emission standards are imposed, the standards could require significant increases in capital expenditures and operating costs which would impact the ultimate retirement of older, less-efficient, coal-fired units. While we expect that costs of complying with new CO_2 and other greenhouse gases emission standards will be treated like all other reasonable costs of serving customers and should be recoverable from customers as costs of doing business, without such recovery those costs could reduce our future net income and cash flows and harm our financial condition.

Courts adjudicating nuisance and other similar claims against us may order us to pay damages or to limit or reduce our CO_2 emissions. – Affecting each Registrant

In the past there have been several cases, and currently there is one pending case, seeking damages based on allegations of federal and state common law nuisance in which we, among others, are defendants. In general, the actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance due to impacts of global warming and climate change. The plaintiffs in these actions generally seek recovery of damages and other relief. If the pending or other future actions are resolved against us, substantial modifications of our existing coal-fired power plants could be required and we might be required to limit or reduce CO_2 emissions. Such remedies could require us to purchase power from third parties to fulfill our commitments to supply power to our customers. This could have a material impact on our costs. In addition, we could be required to invest significantly in additional emission control equipment, accelerate the timing of capital expenditures, pay damages or penalties and/or halt operations. While management believes such costs should be recoverable from customers as costs of doing business in our jurisdictions where generation rates are set on a cost of service basis, without such recovery those costs could reduce our future net income and cash flows and harm our financial condition. Moreover, our results of operations and financial position could be reduced due to the timing of recovery of these investments and the expense of ongoing litigation.

Our revenues and results of operations from selling power are subject to market risks that are beyond our control. – Affecting each Registrant

We sell power from our generation facilities into the spot market and other competitive power markets on a contractual basis. We also enter into contracts to purchase and sell electricity, natural gas, emission allowances and coal as part of our power marketing and energy trading operations. With respect to such transactions, the rate of return on our capital investments is not determined through mandated rates, and our revenues and results of operations are likely to depend, in large part, upon prevailing market prices for power in our regional markets and other competitive markets. These market prices can fluctuate substantially over relatively short periods of time. Trading margins may erode as markets mature and there may be diminished opportunities for gain should volatility decline. In addition, the FERC, which has jurisdiction over wholesale power rates, as well as RTOs that oversee some of these markets, may impose price limitations, bidding rules and other mechanisms to address some of the volatility in these markets. Power supply and other similar agreements entered into during extreme market conditions may subsequently be held to be unenforceable by a reviewing court or the FERC. Fuel and emissions prices may also be volatile, and the price we can obtain for power sales may not change at the same rate as changes in fuel and/or emissions costs. These factors could reduce our margins and therefore diminish our revenues and results of operations. Volatility in market prices for fuel and power may result from:

- Weather conditions, including storms.
- Economic conditions.
- Outages of major generation or transmission facilities.
- Seasonality.
- Power usage.
- Illiquid markets.
- Transmission or transportation constraints or inefficiencies.
- Availability of competitively priced alternative energy sources.
- Demand for energy commodities.
- Natural gas, crude oil and refined products and coal production levels.
- Natural disasters, wars, embargoes and other catastrophic events.
- Federal, state and foreign energy and environmental regulation and legislation.

Our power trading (including coal, gas and emission allowances trading and power marketing) and risk management policies cannot eliminate the risk associated with these activities. – Affecting each Registrant

Our power trading (including coal, gas and emission allowances trading and power marketing) activities expose us to risks of commodity price movements. We attempt to manage our exposure by establishing and enforcing risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate the risks associated with these activities. As a result, we cannot predict the impact that our energy trading and risk management decisions may have on our business, operating results or financial position.

We routinely have open trading positions in the market, within guidelines we set, resulting from the management of our trading portfolio. To the extent open trading positions exist, fluctuating commodity prices can improve or diminish our financial results and financial position.

Our power trading and risk management activities, including our power sales agreements with counterparties, rely on projections that depend heavily on judgments and assumptions by management of factors such as the future market prices and demand for power and other energy-related commodities. These factors become more difficult to predict and the calculations become less reliable the further into the future these estimates are made. Even when our policies and procedures are followed and decisions are made based on these estimates, results of operations may be diminished if the judgments and assumptions underlying those calculations prove to be inaccurate.

Parties with whom we have contracts may fail to perform their obligations, which could harm our results of operations. – Affecting each Registrant

We are exposed to the risk that counterparties that owe us money or power could breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative hedging arrangements or honor underlying commitments at then-current market prices that may exceed our contractual prices, which would cause our financial results to be diminished and we might incur losses. Although our estimates take into account the expected probability of default by a counterparty, our actual exposure to a default by a counterparty may be greater than the estimates predict.

We rely on electric transmission facilities that we do not own or control. If these facilities do not provide us with adequate transmission capacity, we may not be able to deliver our wholesale electric power to the purchasers of our power. – Affecting each Registrant

We depend on transmission facilities owned and operated by other nonaffiliated power companies to deliver the power we sell at wholesale. This dependence exposes us to a variety of risks. If transmission is disrupted, or transmission capacity is inadequate, we may not be able to sell and deliver our wholesale power. If a region's power transmission infrastructure is inadequate, our recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure.

The FERC has issued electric transmission initiatives that require electric transmission services to be offered unbundled from commodity sales. Although these initiatives are designed to encourage wholesale market transactions for electricity and gas, access to transmission systems may in fact not be available if transmission capacity is insufficient because of physical constraints or because it is contractually unavailable. We also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

We do not fully hedge against price changes in commodities. – Affecting each Registrant

We routinely enter into contracts to purchase and sell electricity, natural gas, coal and emission allowances as part of our power marketing and energy and emission allowances trading operations. In connection with these trading activities, we routinely enter into financial contracts, including futures and options, over-the counter options, financially-settled swaps and other derivative contracts. These activities expose us to risks from price movements. If the values of the financial contracts change in a manner we do not anticipate, it could harm our financial position or reduce the financial contribution of our trading operations.

We manage our exposure by establishing risk limits and entering into contracts to offset some of our positions (i.e., to hedge our exposure to demand, market effects of weather and other changes in commodity prices). However, we do not always hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility, our results of operations and financial position may be improved or diminished based upon our success in the market.

Financial derivatives reforms could increase the liquidity needs and costs of our commercial trading operations. – Affecting each Registrant

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was signed into law (Dodd-Frank Act). The federal legislation was enacted to reform financial markets and significantly alter how over-the-counter (OTC) derivatives are regulated. The law increased regulatory oversight of OTC energy derivatives, including: (a) imposing pervasive regulation by the Commodity Futures Trading Commission (CFTC) on dealers and traders who hold significant positions in swaps, (b) requiring certain standardized OTC derivatives to be traded on registered exchanges as directed by CFTC, (c) imposing new and potentially higher capital and margin requirements on swap dealers and traders who hold significant positions in swaps and (d) increasing the monitoring and compliance obligations of parties who engage in swaps, including new recordkeeping and reporting requirements with governmental entities. The CFTC has issued regulations exempting certain end users of energy commodities from being required to clear OTC derivatives, provided that they (a) are using the swaps to hedge or mitigate commercial risk and (b) satisfy certain other requirements. To the extent we meet such requirements, the end user exemption could reduce the effect of the law's clearing requirements on our hedging activity. Pursuant to authority granted under the Dodd-Frank Act, the CFTC has also issued rules that, among other things, further define the OTC derivative products and entities subject to additional regulatory oversight, which recently became effective. These requirements could subject us to additional regulatory oversight related to our OTC derivative transactions, cause our OTC derivative transactions to be more costly and have an impact on financial condition due to additional capital requirements. In addition, as these reforms aim to standardize OTC products it could limit the effectiveness of our hedging programs because we would have less ability to tailor OTC derivatives to match the precise risk we are seeking to manage.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

GENERATION FACILITIES

Utility Operations

As of December 31, 2012, the AEP System owned (or leased where indicated) generating plants, all situated in the states in which our electric utilities serve retail customers, with net maximum power capabilities (winter rating) shown in the following tables:

AEGCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Rockport (Units 1 and 2, 50% of each) (a)	2	IN	Steam - Coal	1,310	1984
Lawrenceburg	6	IN	Natural Gas	1,186	2004
Total MWs				2,496	

(a) Rockport Unit 2 is leased.

APCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Buck	3	VA	Hydro	9	1912
Byllesby	4	VA	Hydro	22	1912
Claytor	4	VA	Hydro	76	1939
Leesville	2	VA	Hydro	50	1964
London	3	WV	Hydro	14	1935
Marmet	3	WV	Hydro	14	1935
Niagara	2	VA	Hydro	2	1906
Reusens	5	VA	Hydro	13	1904
Winfield	3	WV	Hydro	15	1938
Ceredo	6	WV	Natural Gas	516	2001
Dresden	3	OH	Natural Gas	608	2012
Smith Mountain	5	VA	Pumped Storage	586	1965
Amos (Units 1,2 and 3)	3	WV	Steam - Coal	2,033	1971
Clinch River	3	VA	Steam - Coal	705	1958
Glen Lyn	2	VA	Steam - Coal	335	1918
Kanawha River	2	WV	Steam - Coal	400	1953
Mountaineer	1	WV	Steam - Coal	1,320	1980
Sporn	2	WV	Steam - Coal	300	1950
Total MWs				7,018	

I&M

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Berrien Springs	12	MI	Hydro	7	1908
Buchanan	10	MI	Hydro	4	1919
Constantine	4	MI	Hydro	1	1921
Elkhart	3	IN	Hydro	3	1913
Mottville	4	MI	Hydro	2	1923
Twin Branch	6	IN	Hydro	5	1904
Rockport (Units 1 and 2, 50% of each) (a)	2	IN	Steam - Coal	1,310	1984
Tanners Creek	4	IN	Steam - Coal	995	1951
Cook	2	MI	Steam - Nuclear	2,191	1975
Total MWs				4,518	

(a) Rockport Unit 2 is leased.

KPCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Big Sandy	2	KY	Steam - Coal	1,078	1963

OPCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Racine	2	OH	Hydro	48	1982
Darby	6	OH	Natural Gas	507	2001
Waterford	4	OH	Natural Gas	840	2003
Stuart (a)	4	OH	Oil	3	1970
Amos (Unit 3)	1	WV	Steam - Coal	867	1973
Beckjord (a)	1	OH	Steam - Coal	53	1969
Cardinal	1	OH	Steam - Coal	595	1967
Conesville (a)	3	OH	Steam - Coal	1,139	1957
Gavin	2	OH	Steam - Coal	2,640	1974
Kammer	3	WV	Steam - Coal	630	1958
Mitchell	2	WV	Steam - Coal	1,560	1971
Muskingum River	5	OH	Steam - Coal	1,440	1953
Picway	1	OH	Steam - Coal	100	1926
Sporn	2	WV	Steam - Coal	300	1950
Stuart (a)	4	OH	Steam - Coal	600	1971
Zimmer (a)	1	OH	Steam - Coal	330	1991
Total MWs				11,652	

(a) Jointly-owned with non-affiliated entities. Figures presented reflect only the portion owned by OPCo.

PSO

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Comanche	3	OK	Natural Gas	260	1973
Riverside (Units 3 and 4)	2	OK	Natural Gas	157	2008
Southwestern (Units 4 and 5)	2	OK	Natural Gas	170	2008
Tulsa	2	OK	Natural Gas	309	1956
Weleetka	3	OK	Natural Gas	196	1975
Comanche	2	OK	Oil	4	1962
Northeastern	1	OK	Oil	3	1961
Northeastern	1	OK	Oil	1	1980
Riverside	1	OK	Oil	3	1976
Southwestern	1	OK	Oil	2	1962
Weleetka	2	OK	Oil	4	1963
Northeastern (Units 3 and 4)	2	OK	Steam - Coal	930	1979
Oklaunion (a)	1	TX	Steam - Coal	102	1986
Northeastern (Units 1 and 2)	2	OK	Steam - Natural Gas	920	1961
Riverside (Units 1 and 2)	2	OK	Steam - Natural Gas	909	1974
Southwestern (Units 1, 2 and 3)	3	OK	Steam - Natural Gas	466	1952
Total MWs				4,436	

(a) Jointly-owned with TNC and non-affiliated entities. Figures presented reflect only the portion owned by PSO.

SWEPCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Mattison	4	AR	Natural Gas	316	2007
Stall	1	LA	Natural Gas	543	2010
Flint Creek	1	AR	Steam - Coal	264	1978
Turk (a)	1	AR	Steam - Coal	440	2012
Welsh	3	TX	Steam - Coal	1,584	1977
Dolet Hills	1	LA	Steam - Lignite	256	1986
Pirkey	1	TX	Steam - Lignite	580	1985
Arsenal Hill	1	LA	Steam - Natural Gas	110	1960
Knox Lee	4	TX	Steam - Natural Gas	475	1950
Lieberman	4	LA	Steam - Natural Gas	268	1947
Lone Star	1	TX	Steam - Natural Gas	49	1954
Wilkes	3	TX	Steam - Natural Gas	845	1964
Total MWs				5,730	

(a) Figures presented reflect only the portion owned by SWEPCo. The capacity rating for the Turk Plant is accurate as of December 31, 2012. In February 2013, the Turk Plant's capacity was rated at 650 MW, of which 471 MW reflects the portion owned by SWEPCo.

TNC

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant Commissioned
Oklaunion (a)	1	TX	Steam - Coal	355	1986

(a) Jointly-owned with PSO and non-affiliated entities. Figures presented reflect only the portion owned by TNC.

Domestic Independent Power (Generation and Marketing Segment)

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant Commissioned
Trent Mesa	100	TX	Wind	150	2001
Desert Sky	107	TX	Wind	161	2001
Total MWs				311	

The source of fuel in terms of total megawatts as well as a percentage of all of the generation units set forth in the tables above consists of the following:

Coal/Lignite (a)	24,551	65%
Natural Gas/Oil	9,670	26%
Nuclear	2,191	6%
Wind/Hydro/Pumped Storage	1,182	3%
Total MWs Generating Capacity	37,594	100%

(a) Does not include AEP's 43% ownership of OVEC.

Cook Nuclear Plant

The following table provides operating information related to the Cook Plant:

	Cook Plant	
	Unit 1 (a)	**Unit 2**
Year Placed in Operation	1975	1978
Year of Expiration of NRC License	2034	2037
Nominal Net Electrical Rating in Kilowatts	1,084,000	1,107,000
Annual Capacity Utilization		
2012	96.9%	87.4%
2011	81.3%	99.4%
2010	82.2%	80.8%
2009	2.8%	83.1%

(a) Unit 1 Net Capacity Factor for 2009 was impacted by a 2008 forced outage caused by a low pressure turbine blade failure event. The reduced-capacity, repaired turbine was replaced with a full-capacity, new turbine in late 2011.

TRANSMISSION AND DISTRIBUTION FACILITIES

The following table sets forth the total overhead circuit miles of transmission and distribution lines of the AEP System and its operating companies and that portion of the total representing 765kV lines:

	Total Overhead Circuit Miles of Transmission and Distribution Lines	**Circuit Miles of 765kV Lines**
AEP System (a)	229,705 (b)	2,116
APCo	52,307	734
I&M	21,985	615
KGPCo	1,360	-
KPCo	11,140	258
OPCo (a)	46,417	509
PSO	21,021	-
SWEPCo	27,238	-
TCC	29,326	-
TNC	17,171	-
WPCo	1,739	-

(a) Includes 766 miles of 345,000-volt jointly owned lines.
(b) Includes 73 miles of overhead transmission lines not identified with an operating company.

TRANSMISSION OPERATIONS

The following table sets forth the total overhead circuit miles of transmission lines of ETT, OHTCo and OKTCo:

	Total Overhead Circuit Miles of Transmission Lines
ETT	862
OHTCo	61
OKTCo	93

TITLE TO PROPERTY

The AEP System's generating facilities are generally located on lands owned in fee simple. The greater portion of the transmission and distribution lines of the AEP System has been constructed over lands of private owners pursuant to easements or along public highways and streets pursuant to appropriate statutory authority. The rights of AEP's public utility subsidiaries in the realty on which their facilities are located are considered adequate for use in the conduct of their business. Minor defects and irregularities customarily found in title to properties of like size and character may exist, but such defects and irregularities do not materially impair the use of the properties affected thereby. AEP's public utility subsidiaries generally have the right of eminent domain which permits them, if necessary, to acquire, perfect or secure titles to or easements on privately held lands used or to be used in their utility operations. Recent legislation in Ohio and Virginia has restricted the right of eminent domain previously granted for power generation purposes.

SYSTEM TRANSMISSION LINES AND FACILITY SITING

Laws in the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Texas, Tennessee, Virginia and West Virginia require prior approval of sites of generating facilities and/or routes of high-voltage transmission lines. We have experienced delays and additional costs in constructing facilities as a result of proceedings conducted pursuant to such statutes and in proceedings in which our operating companies have sought to acquire rights-of-way through condemnation. These proceedings may result in additional delays and costs in future years.

CONSTRUCTION PROGRAM

With input from its state utility commissions, the AEP System continuously assesses the adequacy of its generation, transmission, distribution and other facilities to plan and provide for the reliable supply of electric power and energy to its customers. In this assessment process, assumptions are continually being reviewed as new information becomes available and assessments and plans are modified, as appropriate. AEP forecasts approximately $3.6 billion of construction expenditures for 2013, excluding equity AFUDC, capitalized interest and assets acquired under leases. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital.

Construction Expenditures

The following table shows construction expenditures (including environmental expenditures) during 2012, 2011 and 2010 and a current estimate of 2013 construction expenditures. Actual amounts for 2012, 2011 and 2010 and budgeted amounts for 2013 exclude equity AFUDC, capitalized interest and assets acquired under leases.

	2013 Estimate (b)	2012 Actual	2011 Actual	2010 Actual
		(in thousands)		
Total AEP System (a)	$ 3,578,000	$ 3,025,000	$ 2,669,000	$ 2,345,000
APCo	370,000	469,052	463,077	534,334
I&M	484,000	317,285	301,241	333,238
OPCo	617,000	517,744	460,125	512,637
PSO	295,000	224,295	140,326	194,896
SWEPCo (b)	398,000	542,427	551,163	420,485

(a) Includes expenditures of other subsidiaries not shown. The figure reflects construction expenditures, not investments in subsidiary companies. Excludes discontinued operations.
(b) Excludes Sabine.

The AEP System construction program is reviewed continuously and is revised from time to time in response to changes in estimates of customer demand, business and economic conditions, the cost and availability of capital, environmental requirements and other factors. Changes in construction schedules and costs and in estimates and projections of needs for additional facilities, as well as variations from currently anticipated levels of net earnings, federal income and other taxes and other factors affecting cash requirements may increase or decrease the estimated capital requirements for the AEP System's construction program.

POTENTIAL UNINSURED LOSSES

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 liabilities relating to damage to our generating plants and costs of replacement power. Unless allowed to be recovered through rates, future losses or liabilities which are not completely insured could reduce net income and impact the financial conditions of AEP and other AEP System companies. For risks related to owning a nuclear generating unit, see Note 5 to the consolidated financial statements entitled Commitments, Guarantees and Contingencies under the heading Nuclear Contingencies for information with respect to nuclear incident liability insurance.

ITEM 3. LEGAL PROCEEDINGS

For a discussion of material legal proceedings, see Note 5 to the consolidated financial statements, entitled Commitments, Guarantees and Contingencies, incorporated by reference in Item 8.

ITEM 4. MINE SAFETY DISCLOSURE

The Federal Mine Safety and Health Act of 1977 (Mine Act) imposes stringent health and safety standards on various mining operations. The Mine Act and its related regulations affect numerous aspects of mining operations, including training of mine personnel, mining procedures, equipment used in mine emergency procedures, mine plans and other matters. SWEPCo, through its ownership of Dolet Hills Lignite Company (DHLC), a wholly-owned lignite mining subsidiary of SWEPCo, and OPCo, through its ownership of Conesville Coal Preparation Company (CCPC) and its use of the Conner Run fly ash impoundment, are subject to the provisions of the Mine Act. OPCo is in the process of selling CCPC.

The Dodd-Frank Wall Street Reform and Consumer Protection Act and the regulations promulgated thereunder require companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act. Exhibit 95 "Mine Safety Disclosure Exhibit" contains the notices of violation and proposed assessments received by DHLC, CCPC and Conner Run under the Mine Act for the year ended December 31, 2012.

PART II

ITEM 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

AEP

In addition to the discussion below, the remaining information required by this item is incorporated herein by reference to the material under AEP Common Stock and Dividend Information and Note 13 to the consolidated financial statements entitled Financing Activities under the heading Dividend Restrictions in the 2012 Annual Report.

APCo, I&M, OPCo, PSO and SWEPCo

The common stock of these companies is held solely by AEP. The information regarding the amounts of cash dividends on common stock paid by these companies to AEP during 2012, 2011 and 2010 are incorporated by reference to the material under Statements of Changes in Common Shareholder's Equity and Note 13 to the consolidated financial statements entitled Financing Activities under the heading Dividend Restrictions in the 2012 Annual Reports.

During the quarter ended December 31, 2012, neither AEP nor its publicly-traded subsidiaries purchased equity securities that are registered by AEP or its publicly-traded subsidiaries pursuant to Section 12 of the Exchange Act.

ITEM 6. SELECTED FINANCIAL DATA

AEP

The information required by this item is incorporated herein by reference to the material under Selected Consolidated Financial Data in the 2012 Annual Reports.

APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(a). Management's narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under Management's Discussion and Analysis of Financial Condition and Results of Operations in the 2012 Annual Reports.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

AEP

The information required by this item is incorporated herein by reference to the material under Management's Discussion and Analysis of Financial Condition and Results of Operations in the 2012 Annual Reports.

APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(a). Management's narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under Management's Discussion and Analysis of Financial Condition and Results of Operations in the 2012 Annual Reports.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

AEP, APCo, I&M, OPCo, PSO and SWEPCo

The information required by this item is incorporated herein by reference to the material under Management's Discussion and Analysis of Financial Condition and Results of Operations – Quantitative and Qualitative Disclosures about Market and Credit Risk in the 2012 Annual Reports.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

AEP, APCo, I&M, OPCo, PSO and SWEPCo

The information required by this item is incorporated herein by reference to the financial statements and financial statement schedules described under Item 15 herein.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

AEP, APCo, I&M, OPCo, PSO and SWEPCo

None.

ITEM 9A. CONTROLS AND PROCEDURES

During 2012, management, including the principal executive officer and principal financial officer of each of American Electric Power Company, Inc., Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company (each a "Registrant" and collectively the "Registrants") evaluated each respective Registrant's disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the Commission's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to each Registrant's management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of December 31, 2012, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

There have been no changes in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth quarter of 2012 that materially affected, or are reasonably likely to materially affect, the Registrants' internal control over financial reporting.

Management is required to assess and report on the effectiveness of its internal control over financial reporting as of December 31, 2012. As a result of that assessment, management determined that there were no material weaknesses as of December 31, 2012 and, therefore, concluded that each Registrant's internal control over financial reporting was effective.

Additional information required by this item of the Registrants is incorporated by reference to Management's Report on Internal Control over Financial Reporting, included in the 2012 Annual Report of each Registrant.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

AEP

Directors, Director Nomination Process and Audit Committee

Certain of the information called for in this Item 10, including the information relating to directors, is incorporated herein by reference to AEP's definitive proxy information statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to 2013 Annual Meeting of Shareholders (the 2013 Annual Meeting) including under the captions "Election of Directors," "Section 16(a) Beneficial Ownership Reporting Compliance," "AEP's Board of Directors and Committees," "Directors," "Involvement by Mr. Hoaglin in Certain Legal Proceedings" and "Shareholder Nominees for Directors."

Executive Officers

Reference also is made to the information under the caption Executive Officers of the Registrants in Part I, Item 4 of this report.

Code of Ethics

AEP's Principles of Business Conduct is the code of ethics that applies to AEP's Chief Executive Officer, Chief Financial Officer and principal accounting officer. The Principles of Business Conduct is available on AEP's website at www.aep.com. The Principles of Business Conduct will be made available, without charge, in print to any shareholder who requests such document from Investor Relations, American Electric Power Company, Inc., 1 Riverside Plaza, Columbus, Ohio 43215.

If any substantive amendments to the Principles of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Principles of Business Conduct, to its Chief Executive Officer, Chief Financial Officer or principal accounting officer, AEP will disclose the nature of such amendment or waiver on AEP's website, www.aep.com, or in a report on Form 8-K.

Section 16(a) Beneficial Ownership Reporting Compliance

The information required by this item is incorporated herein by reference to information contained in the definitive proxy statement of AEP for the 2013 Annual Meeting.

ITEM 11. EXECUTIVE COMPENSATION

APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

AEP

The information called for by this Item 11 is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2013 Annual Meeting including under the captions "Compensation Discussion and Analysis," "Executive Compensation", "Director Compensation" and "2012 Director Compensation Table". The information set forth under the subcaption "Human Resources Committee Report" and "Audit Committee Report" should not be deemed filed nor should it be incorporated by reference into any other filing under the Securities Act of 1933, as amended, or the Exchange Act except to the extent we specifically incorporate such report by reference therein.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

AEP

The information relating to Security Ownership of Certain Beneficial Owners is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to 2013 Annual Meeting under the caption "Share Ownership of Certain Beneficial Owners and Management" and "Share Ownership of Directors and Executive Officers."

EQUITY COMPENSATION PLAN INFORMATION

The following table summarizes the ability of AEP to issue common stock pursuant to equity compensation plans as of December 31, 2012:

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options Warrants and Rights	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans (Excluding Securities Reflected in Column A(a)
Equity Compensation Plans Approved by Security Holders (b)	188,472	$ 30.17	17,907,559
Equity Compensation Plans Not Approved by Security Holders	-	-	-
Total	188,472	$ 30.17	17,907,559

(a) AEP deducts equity compensation granted in stock units that are paid in cash, rather than AEP common shares, such as AEP's performance units and deferred stock units, from the number of shares available for future grants under the Amended and Restated American Electric Power System Long-Term Incentive Plan. The number of shares available under this plan would be 1,091,485 higher if equity compensation that is paid in cash were not deducted from this column.

(b) Consists of shares to be issued upon exercise of outstanding options granted under the Amended and Restated American Electric Power System Long-Term Incentive Plan.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

AEP

The information called for by this Item 13 is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2013 Annual Meeting under the captions "Transactions with Related Persons" and "Director Independence."

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

AEP

The information called for by this Item 14 is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2013 Annual Meeting under the captions "Audit and Non-Audit Fees," "Audit Committee Report" and "Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of the Independent Auditor."

APCo, I&M, OPCo, PSO and SWEPCo

Each of the above is a wholly-owned subsidiary of AEP and does not have a separate audit committee. A description of the AEP Audit Committee pre-approval policies, which apply to these companies, is contained in the definitive proxy statement of AEP for the 2013 Annual Meeting of shareholders. The following table presents directly billed fees for professional services rendered by Deloitte & Touche LLP for the audit of these companies' annual financial statements for the years ended December 31, 2012 and 2011, and fees directly billed for other services rendered by Deloitte & Touche LLP during those periods. Deloitte & Touche LLP also provides additional professional and other services to the AEP System, the cost of which may ultimately be allocated to these companies though not billed directly to them. For a description of these fees and services, see the description of principal accounting fees and services for AEP, above.

	APCo		I&M		OPCo	
	2012	**2011**	**2012**	**2011**	**2012**	**2011**
Audit Fees	$ 2,026,590	$ 2,241,610	$ 1,447,948	$ 1,610,206	$ 2,459,868	$ 2,849,269
Audit-Related Fees	57,556	6,900	47,022	6,900	60,901	6,900
Tax Fees	22,623	9,000	16,806	12,000	28,842	18,000
Total	$ 2,106,769	$ 2,257,510	$ 1,511,776	$ 1,629,106	$ 2,549,611	$ 2,874,169

	PSO		SWEPCo	
	2012	**2011**	**2012**	**2011**
Audit Fees	$ 612,686	$ 714,097	$ 1,014,601	$ 894,582
Audit-Related Fees	25,125	6,900	778,130	70,900
Tax Fees	7,177	9,000	11,413	8,977
Total	$ 644,988	$ 729,997	$ 1,804,144	$ 974,459

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as a part of this report:

1. **FINANCIAL STATEMENTS:**
The following financial statements have been incorporated herein by reference pursuant to Item 8.

AEP and Subsidiary Companies:
Reports of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Income for the years ended December 31, 2012, 2011 and 2010; Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2012, 2011 and 2010; Consolidated Statements of Changes in Equity for the years ended December 31, 2012, 2011 and 2010; Consolidated Balance Sheets as of December 31, 2012 and 2011; Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010; Notes to Consolidated Financial Statements.

APCo, I&M and OPCo:
Consolidated Statements of Income for the years ended December 31, 2012, 2011 and 2010; Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2012, 2011 and 2010; Consolidated Statements of Changes in Common Shareholder's Equity for the years ended December 31, 2012, 2011 and 2010; Consolidated Balance Sheets as of December 31, 2012 and 2011; Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting.

PSO:
Statements of Income for the years ended December 31, 2012, 2011 and 2010; Statements of Comprehensive Income (Loss) for the years ended December 31, 2012, 2011 and 2010; Statements of Changes in Common Shareholder's Equity for the years ended December 31, 2012, 2011 and 2010; Balance Sheets as of December 31, 2012 and 2011; Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting.

SWEPCo:
Consolidated Statements of Income for the years ended December 31, 2012, 2011 and 2010; Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2012, 2011 and 2010; Consolidated Statements of Changes in Equity for the years ended December 31, 2012, 2011 and 2010; Consolidated Balance Sheets as of December 31, 2012 and 2011; Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting.

	Page Number
2. **FINANCIAL STATEMENT SCHEDULES:** Financial Statement Schedules are listed in the Index of Financial Statement Schedules. (Certain schedules have been omitted because the required information is contained in the notes to financial statements or because such schedules are not required or are not applicable). Reports of Independent Registered Public Accounting Firm.	S-1
3. **EXHIBITS:** Exhibits for AEP, APCo, I&M, OPCo, PSO and SWEPCo are listed in the Exhibit Index beginning on page E-1 and are incorporated herein by reference.	E-1

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

American Electric Power Company, Inc.

By: /s/ Brian X. Tierney
(Brian X. Tierney, Executive Vice President and Chief Financial Officer)

Date: February 26, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ Nicholas K. Akins **(Nicholas K. Akins)**	Chief Executive Officer, President and Director	February 26, 2013
(ii) Principal Financial Officer:		
/s/ Brian X. Tierney **(Brian X. Tierney)**	Executive Vice President and Chief Financial Officer	February 26, 2013
(iii) Principal Accounting Officer:		
/s/ Joseph M. Buonaiuto **(Joseph M. Buonaiuto)**	Senior Vice President, Controller and Chief Accounting Officer	February 26, 2013
(iv) A Majority of the Directors:		
*Nicholas K. Akins *David J. Anderson * James F. Cordes * Ralph D. Crosby, Jr. *Linda A. Goodspeed *Thomas E. Hoaglin *Sandra Beach Lin *Michael G. Morris *Richard C. Notebaert *Lionel L. Nowell, III *Stephen S. Rasmussen *Oliver G. Richard, III *Richard L. Sandor *Sara Martinez Tucker *John F. Turner		
*By: /s/ Brian X. Tierney **(Brian X. Tierney, Attorney-in-Fact)**		February 26, 2013

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Appalachian Power Company
Ohio Power Company
Public Service Company of Oklahoma
Southwestern Electric Power Company

By: /s/ Brian X. Tierney
(Brian X. Tierney, Executive Vice President and Chief Financial Officer)

Date: February 26, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) **Principal Executive Officer:**		
/s/ Nicholas K. Akins **(Nicholas K. Akins)**	Chief Executive Officer and Director	February 26, 2013
(ii) **Principal Financial Officer:**		
/s/ Brian X. Tierney **(Brian X. Tierney)**	Vice President, Chief Financial Officer and Director	February 26, 2013
(iii) **Principal Accounting Officer:**		
/s/ Joseph M. Buonaiuto **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 26, 2013
(iv) **A Majority of the Directors:**		
*Nicholas K. Akins *Lisa M. Barton *David M. Feinberg *Lana L. Hillebrand *Mark C. McCullough *Robert P. Powers *Dennis E. Welch		
*By: /s/ Brian X. Tierney **(Brian X. Tierney, Attorney-in-Fact)**		February 26, 2013

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Indiana Michigan Power Company

By: /s/ Brian X. Tierney
(Brian X. Tierney, Executive Vice President and Chief Financial Officer)

Date: February 26, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ Nicholas K. Akins **(Nicholas K. Akins)**	Chief Executive Officer and Director	February 26, 2013
(ii) Principal Financial Officer:		
/s/ Brian X. Tierney **(Brian X. Tierney)**	Vice President, Chief Financial Officer and Director	February 26, 2013
(iii) Principal Accounting Officer:		
/s/ Joseph M. Buonaiuto **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 26, 2013
(iv) A Majority of the Directors:		
*Nicholas K. Akins *Lisa M. Barton *Sarah L. Bodner *Paul Chodak, III *J. Edward Ehler *Scott M. Krawec *Marc E. Lewis *Mark C. McCullough *Robert P. Powers *Carla E. Simpson		
*By: /s/ Brian X. Tierney **(Brian X. Tierney, Attorney-in-Fact)**		February 26, 2013

INDEX OF FINANCIAL STATEMENT SCHEDULES

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.:

We have audited the consolidated financial statements of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2012 and 2011, and for each of the three years in the period ended December 31, 2012, and the Company's internal control over financial reporting as of December 31, 2012, and have issued our reports thereon dated February 26, 2013; such consolidated financial statements and our reports are included in the Company's 2012 Annual Report and are incorporated herein by reference. Our audits also included the financial statement schedules of the Company listed in Item 15. These financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 26, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Appalachian Power Company
Indiana Michigan Power Company
Ohio Power Company
Public Service Company of Oklahoma
Southwestern Electric Power Company

We have audited the financial statements of Appalachian Power Company and subsidiaries, Indiana Michigan Power Company and subsidiaries, Ohio Power Company and subsidiary, Public Service Company of Oklahoma and Southwestern Electric Power Company Consolidated (collectively the "Companies") as of December 31, 2012 and 2011, and for each of the three years in the period ended December 31, 2012, and have issued our reports thereon dated February 26, 2013; such financial statements and reports are included in the Companies' 2012 Annual Reports and are incorporated herein by reference. Our audits also included the financial statement schedule of each of the Companies listed in Item 15. These financial statement schedules are the responsibility of the Companies' management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 26, 2013

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011 and 2010
(in millions, except per-share and share amounts)

	Years Ended December 31,		
	2012	2011	2010
REVENUES			
Affiliated Revenues	$ 4	$ 5	$ 4
EXPENSES			
Other Operation	22	23	54
OPERATING LOSS	(18)	(18)	(50)
Other Income (Expense):			
Interest Income	22	19	22
Interest Expense	(90)	(42)	(52)
LOSS BEFORE INCOME TAX CREDIT AND EQUITY EARNINGS	(86)	(41)	(80)
Income Tax Credit	-	2	-
Equity Earnings of Unconsolidated Subsidiaries	1,345	1,980	1,291
NET INCOME	1,259	1,941	1,211
Other Comprehensive Income (Loss)	133	(89)	(7)
TOTAL COMPREHENSIVE INCOME	$ 1,392	$ 1,852	$ 1,204
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	484,682,469	482,169,282	479,373,306
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.60	$ 4.02	$ 2.53
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	485,084,694	482,460,328	479,601,442
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.60	$ 4.02	$ 2.53

See Condensed Notes to Condensed Financial Information beginning on page S-7.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED BALANCE SHEETS
ASSETS
December 31, 2012 and 2011
(in millions)

	December 31, 2012	December 31, 2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 166	$ 127
Other Temporary Investments	2	2
Advances to Affiliates	650	944
Accounts Receivable:		
General	71	17
Affiliated Companies	36	43
Total Accounts Receivable	107	60
Prepayments and Other Current Assets	5	7
TOTAL CURRENT ASSETS	930	1,140
PROPERTY, PLANT AND EQUIPMENT		
General	1	2
Total Property, Plant and Equipment	1	2
Accumulated Depreciation and Amortization	1	2
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET	-	-
OTHER NONCURRENT ASSETS		
Investments in Unconsolidated Subsidiaries	15,679	15,170
Affiliated Notes Receivable	285	290
Deferred Charges and Other Noncurrent Assets	54	59
TOTAL OTHER NONCURRENT ASSETS	16,018	15,519
TOTAL ASSETS	$ 16,948	$ 16,659

See Condensed Notes to Condensed Financial Information beginning on page S-7.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2012 and 2011
(dollars in millions)

	December 31, 2012	December 31, 2011
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 1	$ 1
Affiliated Companies	435	445
Long-term Debt Due Within One Year	5	1
Short-term Debt	321	967
Other Current Liabilities	74	7
TOTAL CURRENT LIABILITIES	836	1,421
NONCURRENT LIABILITIES		
Long-term Debt	847	554
Deferred Credits and Other Noncurrent Liabilities	28	20
TOTAL NONCURRENT LIABILITIES	875	574
TOTAL LIABILITIES	1,711	1,995
COMMON SHAREHOLDERS' EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2012	2011
Shares Authorized	600,000,000	600,000,000
Shares Issued	506,004,962	503,759,460

	2012	2011
(20,336,592 Shares were Held in Treasury as of December 31, 2012 and 2011)	3,289	3,274
Paid-in Capital	6,049	5,970
Retained Earnings	6,236	5,890
Accumulated Other Comprehensive Income (Loss)	(337)	(470)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	15,237	14,664
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 16,948	$ 16,659

See Condensed Notes to Condensed Financial Information beginning on page S-7.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011 and 2010
(in millions)

	Years Ended December 31,		
	2012	2011	2010
OPERATING ACTIVITIES			
Net Income	$ 1,259	$ 1,941	$ 1,211
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Equity Earnings of Unconsolidated Subsidiaries	(1,345)	(1,980)	(1,291)
Cash Dividends Received from Unconsolidated Subsidiaries	1,294	1,113	854
Change in Other Noncurrent Assets	13	2	-
Change in Other Noncurrent Liabilities	22	20	14
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(47)	72	(93)
Accounts Payable	(10)	(103)	89
Other Current Liabilities	72	(3)	(12)
Net Cash Flows from Operating Activities	1,258	1,062	772
INVESTING ACTIVITIES			
Purchases of Investment Securities	-	(69)	(333)
Sales of Investment Securities	-	166	267
Change in Advances to Affiliates, Net	294	(388)	(299)
Capital Contributions to Unconsolidated Subsidiaries	(325)	(99)	(6)
Issuance of Notes Receivable to Affiliated Companies	-	-	(20)
Repayments of Notes Receivable from Affiliated Companies	5	5	300
Net Cash Flows Used for Investing Activities	(26)	(385)	(91)
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	83	92	93
Issuance of Long-term Debt	843	-	-
Commercial Paper and Credit Facility Borrowings	-	429	466
Change in Short-term Debt, Net	(646)	769	80
Retirement of Long-term Debt	(558)	-	(490)
Change in Advances from Affiliates, Net	-	(295)	6
Commercial Paper and Credit Facility Repayments	-	(881)	(15)
Dividends Paid on Common Stock	(911)	(892)	(820)
Other Financing Activities	(4)	(3)	(3)
Net Cash Flows Used for Financing Activities	(1,193)	(781)	(683)
Net Increase (Decrease) in Cash and Cash Equivalents	39	(104)	(2)
Cash and Cash Equivalents at Beginning of Period	127	231	233
Cash and Cash Equivalents at End of Period	$ 166	$ 127	$ 231

See Condensed Notes to Condensed Financial Information beginning on page S-7.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL INFORMATION

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The condensed financial information of AEP (Parent) is required as a result of the restricted net assets of consolidated subsidiaries exceeding 25% of consolidated net assets as of December 31, 2012. Parent is a public utility holding company that owns all of the outstanding common stock of its public utility subsidiaries and varying percentages of other subsidiaries, including joint ventures and equity investments. The primary source of income for Parent is equity in its subsidiaries' earnings. Its major source of cash is dividends from the subsidiaries. Parent borrows the funds for the money pool that is used by the subsidiaries for their short-term cash needs.

Income Taxes

Parent files a consolidated federal income tax return with its subsidiaries. The AEP System's current consolidated federal income tax is allocated to the AEP System companies so that their current tax expense reflects a separate return result for each company in the consolidated group. The tax benefit of Parent is allocated to its subsidiaries with taxable income.

2. COMMITMENTS, GUARANTEES AND CONTINGENCIES

Parent and its subsidiaries are parties to environmental and other legal matters. For further discussion of commitments, guarantees and contingencies, see Note 5 in the 2012 Annual Reports.

3. FINANCING ACTIVITIES

The following details long-term debt outstanding as of December 31, 2012 and 2011:

Long-term Debt

Type of Debt and Maturity	Interest Rate Ranges as of December 31, 2012	Interest Rate Ranges as of December 31, 2011	Outstanding as of December 31, 2012	Outstanding as of December 31, 2011
			(in millions)	
Senior Unsecured Notes (a)				
2015-2022	1.65% - 2.95%	5.25%	$ 850	$ 243
Junior Subordinated Debentures (a)				
2063		8.75%	-	315
Fair Value of Interest Rate Hedges			3	7
Unamortized Discount, Net			(1)	(10)
Total Long-term Debt Outstanding			852	555
Long-term Debt Due Within One Year			5	1
Long-term Debt			$ 847	$ 554

(a) In 2012, Parent issued $850 million of Senior Unsecured Notes used to retire $243 million of Senior Unsecured Notes and $315 million of Junior Subordinated Debentures.

Long-term debt outstanding as of December 31, 2012 is payable as follows:

	2013	2014	2015	2016	2017	After 2017	Total
				(in millions)			
Principal Amount	$ 5	$ 2	$ 3	$ (2)	$ 545	$ 300	$ 853
Unamortized Discount, Net							(1)
Total Long-term Debt Outstanding							$ 852

Short-term Debt

Parent's outstanding short-term debt was as follows:

	December 31,					
	2012			2011		
Type of Debt	Outstanding Amount		Weighted Average Interest Rate	Outstanding Amount		Weighted Average Interest Rate
	(in millions)			(in millions)		
Commercial Paper	$	321	0.42 %	$	967	0.51 %
Total Short-term Debt	$	321		$	967	

4. RELATED PARTY TRANSACTIONS

Payments on Behalf of Subsidiaries

Due to occasional time sensitivity and complexity of payments, Parent makes certain insurance, tax and benefit payments on behalf of subsidiary companies. Parent is then fully reimbursed by the subsidiary companies.

Short-term Lending to Subsidiaries

Parent uses a commercial paper program to meet the short-term borrowing needs of subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The program also allows some direct borrowers to invest excess cash with Parent.

Interest expense related to Parent's short-term borrowing is included in Interest Expense on Parent's statements of income. Parent incurred interest expense for amounts borrowed from subsidiaries of $11 thousand, $199 thousand and $1 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Interest income related to Parent's short-term lending is included in Interest Income on Parent's statements of income. Parent earned interest income for amounts advanced to subsidiaries of $5 million, $3 million and $2 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Global Borrowing Notes

Parent issued long-term debt, portions of which were loaned to its subsidiaries. Parent pays interest on the global notes, but the subsidiaries accrue interest for their share of the global borrowing and remit the interest to Parent. Interest income related to Parent's loans to subsidiaries is included in Interest Income on Parent's statements of income. Parent earned interest income on loans to subsidiaries of $15 million, $15 million and $18 million for the years ended December 31, 2012, 2011 and 2010, respectively.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

AEP

Description	Balance at Beginning of Period	BlueStar Acquisition in March 2012	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)			
Deducted from Assets:						
Accumulated Provision for Uncollectible Accounts:						
Year Ended December 31, 2012	$ 32,551	$ 344	$ 52,399	$ 2,815	$ 52,443	$ 35,666
Year Ended December 31, 2011	41,555	-	36,457	1,994	47,455	32,551
Year Ended December 31, 2010	37,399	-	36,699	(1,036)	31,507	41,555

(a) Recoveries offset by reclasses to other liabilities.
(b) Uncollectible accounts written off.

APCo

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2012	$ 5,289	$ 15,652	$ 1,689	$ 16,543	$ 6,087
Year Ended December 31, 2011	6,667	6,041	1,535	8,954	5,289
Year Ended December 31, 2010	5,408	6,573	292	5,606	6,667

(a) Recoveries offset by reclasses to other liabilities.
(b) Uncollectible accounts written off.

I&M

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2012	$ 1,750	$ 20	$ -	$ 1,541	$ 229
Year Ended December 31, 2011	1,692	151	-	93	1,750
Year Ended December 31, 2010	2,265	(139)(c)	(424)	10	1,692

(a) Recoveries offset by reclasses to other liabilities.
(b) Uncollectible accounts written off.
(c) Recoveries on previous reserve balance.

OPCo

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2012	$ 3,563	$ (9)(c)	$ 43	$ 3,468	$ 129
Year Ended December 31, 2011	3,768	59	(10)	254	3,563
Year Ended December 31, 2010	6,146	59	(928)	1,509	3,768

(a) Recoveries offset by reclasses to other liabilities.
(b) Uncollectible accounts written off.
(c) Recoveries on previous reserve balance.

PSO

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2012	$ 777	$ 95	$ -	$ -	$ 872
Year Ended December 31, 2011	971	(194)(c)	-	-	777
Year Ended December 31, 2010	304	709	-	42	971

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.
(c) Recoveries on previous reserve balance.

SWEPCo

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2012	$ 989	$ 71	$ 981	$ -	$ 2,041
Year Ended December 31, 2011	588	149	376	124	989
Year Ended December 31, 2010	64	400	166	42	588

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

EXHIBIT INDEX

The documents listed below are being filed or have previously been filed on behalf of the Registrants shown and are incorporated herein by reference to the documents indicated and made a part hereof. Exhibits ("Ex") not identified as previously filed are filed herewith. Exhibits designated with a dagger (†) are management contracts or compensatory plans or arrangements required to be filed as an Exhibit to this Form. Exhibits designated with an asterisk (*) are filed herewith.

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
AEP‡ File No. 1-3525		
3(a)	Composite of the Restated Certificate of Incorporation of AEP, dated April 28, 2009.	2009 Form 10-K, Ex 3(a)
3(b)	Composite By-Laws of AEP, as amended as of September 25, 2012.	Form 8-K, Ex 3.1 dated September 26, 2012
4(a)	Indenture (for unsecured debt securities), dated as of May 1, 2001, between AEP and The Bank of New York, as Trustee.	Registration Statement No. 333-86050, Ex 4(a)(b)(c) Registration Statement No. 333-105532, Ex 4(d)(e)(f)
4(b)	Company Order and Officer's Certificate to The Bank of New York Mellon Trust Company, N.A. dated December 3, 2012 establishing terms 1.65% Senior Notes, Series E, due 2017 and 2.95% Senior Notes, Series F, due 2022.	Form 8-K, Ex. 4(a) dated December 3, 2012.
*4(c)	$1.75 Billion Second Amended and Restated Credit Agreement, dated as of February 13, 2013, among AEP, the banks, financial institutions and other institutional lenders listed on the signature pages thereof, and JP Morgan Chase Bank, N.A., as Administrative Agent.	
*4(d)	$1.75 Billion Amended and Restated Credit Agreement, dated as of February 13, 2013, among AEP, the banks, financial institutions and other institutional lenders listed on the signature pages thereof, and Barclays Bank PLC as Administrative Agent.	
*4(e)	$1 Billion Term Credit Agreement, dated as of February 13, 2013, among AEP, the banks, financial institutions and other institutional lenders listed on the signature pages thereof, and Wells Fargo Bank, National Association, as Administrative Agent.	
10(a)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a) Registration Statement No. 2-61009, Ex 5(b) 1990 Form 10-K, Ex 10(a)(3)
10(b)	Restated and Amended Operating Agreement, among PSO, SWEPCo and AEPSC, Issued on February 10, 2006, Effective May 1, 2006.	Form 10-Q, Ex 10(b), March 31, 2006

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	1985 Form 10-K, Ex 10(b) 1988 Form 10-K, Ex 10(b)(2)
10(d)	Transmission Coordination Agreement dated January 1, 1997, restated and amended by and among PSO, SWEPCo and AEPSC.	
10(e)	Amended and Restated Operating Agreement dated as of June 2, 1997, of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, KGPCo and WPCo.	2004 Form 10-K, Ex 10(e)(1)
10(e)(1)	PJM West Reliability Assurance Agreement, dated as of March 14, 2001, among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(e)(2)
10(e)(2)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, KGPCo and WPCo.	2004 Form 10-K, Ex 10(e)(3)
10(f)	Lease Agreements, dated as of December 1, 1989, between AEGCo or I&M and Wilmington Trust Company, as amended.	Registration Statement No. 33-32752, Ex 28(c)(1-6)(C) Registration Statement No. 33-32753, Ex 28(a)(1-6)(C) AEGCo 1993 Form 10-K, Ex 10(c)(1-6)(B) I&M 1993 Form 10-K, Ex 10(e)(1-6)(B)
10(g)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	1996 Form 10-K, Ex 10(l)
10(h)	Consent Decree with U.S. District Court dated October 9, 2007.	Form 8-K, Ex 10.1 dated October 9, 2007
†10(i)	AEP Accident Coverage Insurance Plan for Directors.	1985 Form 10-K, Ex 10(g)
†10(j)	AEP Retainer Deferral Plan for Non-Employee Directors, effective January 1, 2005, as amended February 9, 2007.	2007 Form 10-K, Ex 10(j)(i)
†10(k)	Amended and Restated AEP Stock Unit Accumulation Plan for Non-Employee Directors effective January 1, 2013.	Form 10-Q, Ex 10, March 31, 2012
†10(l)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(l)(1)(A)
†10(l)(1)	Guaranty by AEP of AEPSC Excess Benefits Plan.	1990 Form 10-K, Ex 10(h)(1)(B)
†10(l)(2)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2011 (Non-Qualified).	2010 Form 10-K, Ex 10(l)(2)
†10(l)(3)	AEPSC Umbrella Trust for Executives.	1993 Form 10-K, Ex 10(g)(3)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
†10(l)(3)(A)	First Amendment to AEPSC Umbrella Trust for Executives.	2008 Form 10-K, Ex 10(l)(3)(A)
†10(m)	Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.	2002 Form 10-K, Ex 10(m)(4)
†10(m)(1)(A)	Amendment to Employment Agreement dated December 9, 2008 between AEPSC and Robert P. Powers.	2008 Form 10-K, Ex 10(m)(4)(A)
†10(n)	AEP System Senior Officer Annual Incentive Compensation Plan amended and restated as of February 26, 2013.	Form 10-Q, Ex 10, June 30, 2012
†10(o)	AEP System Survivor Benefit Plan, effective January 27, 1998.	Form 10-Q, Ex 10, September 30, 1998
†10(o)(1)(A)	First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.	2002 Form 10-K, Ex 10(o)(2)
†10(o)(2)(A)	Second Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 1, 2008.	2008 Form 10-K, Ex 10(o)(1)(B)
†10(p)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(p)
†10(p)(1)(A)	First Amendment to AEP Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2008.	2011 Form 10-K, Ex 10(p)(1)(A)
†10(q)	AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.	2002 Form 10-K, Ex 10(r)
†10(r)	Nuclear Key Contributor Retention Plan Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(r)
†10(r)(1)(A)	First Amendment to Nuclear Key Contributor Retention Plan Amended and Restated as of January 1, 2008.	2011 Form 10-K, Ex 10(r)(1)(A)
*†10(s)	AEP Change In Control Agreement, effective January 1, 2013.	
†10(t)	Amended and Restated AEP System Long-Term Incentive Plan as of September 25, 2012.	Form 10-Q, Ex 10, September 30, 2010
†10(t)(1)(A)	Performance Share Award Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	2011 Form 10-K, Ex 10(t)(1)(A)
*†10(t)(2)(A)	Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan Amended and Restated effective January 1, 2013.	

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
†10(u)	AEP System Stock Ownership Requirement Plan Amended and Restated effective January 1, 2010.	2010 Form 10-K, Ex 10(u)
†10(u)(1)(A)	First Amendment to AEP System Stock Ownership Requirement Plan as Amended and Restated effective January 1, 2010.	2011 Form 10-K, Ex 10(u)(1)(A)
†10(v)	Central and South West System Special Executive Retirement Plan Amended and Restated effective January 1, 2009.	2008 Form 10-K, Ex 10(v)
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the AEP 2012 Annual Report (for the fiscal year ended December 31, 2012) which are incorporated by reference in this filing.	
*21	List of subsidiaries of AEP.	
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
101.INS	XBRL Instance Document.	
101.SCH	XBRL Taxonomy Extension Schema.	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
APCo‡ File No. 1-3457		
3(a)	Composite of the Restated Articles of Incorporation of APCo, amended as of March 7, 1997.	1996 Form 10-K, Ex 3(d)
3(b)	Composite By-Laws of APCo, amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)
4(a)	Indenture (for unsecured debt securities), dated as of January 1, 1998, between APCo and The Bank of New York, As Trustee.	Registration Statement No. 333-45927, Ex 4(a)(b) Registration Statement No. 333-49071, Ex 4(b) Registration Statement No. 333-84061, Ex 4(b)(c) Registration Statement No. 333-100451, Ex 4(b)(c)(d) Registration Statement No. 333-116284, Ex 4(b)(c) Registration Statement No. 333-123348, Ex 4(b)(c) Registration Statement No. 333-136432, Ex 4(b)(c)(d) Registration Statement No. 333-161940, Ex 4(b)(c)(d) Registration Statement No. 333-182336, Ex 4(b)(c)
4(b)	Company Order and Officer's Certificate to The Bank of New York Mellon Trust Company, N.A., dated August 16, 2012 establishing terms of Floating Rate Notes due 2013.	Form 8-K, Ex 4(a) dated August 16, 2012
10(a)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a) Registration Statement No. 2-63234, Ex 5(a)(1)(B) Registration Statement No 2-66301, Ex 5(a)(1)(C) Registration Statement No. 2-67728, Ex 5(a)(1)(D) 1989 Form 10-K, Ex 10(a)(1)(F) 1992 Form 10-K, Ex 10(a)(1)(B)
10(a)(1)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended March 13, 2006.	2005 Form 10-K, Ex 10(a)(2)
10(a)(2)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.	Registration Statement No. 2-60015, Ex 5(e)
10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a) Registration Statement No. 2-61009, Ex 5(b) 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	1985 Form 10-K, Ex 10(b) 1988 Form 10-K, Ex 10(b)(2)
10(d)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, KGPCo and WPCo.	2004 Form 10-K, Ex 10(d)(1)
10(d)(1)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(d)(2)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
10(d)(2)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, KGPCo and WPCo.	2004 Form 10-K, Ex 10(d)(3)
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	1996 Form 10-K, Ex 10(l), File No. 1-3525
10(f)	Consent Decree with U.S. District Court.	Form 8-K, Ex 10.1 dated October 9, 2007
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the APCo 2012 Annual Report (for the fiscal year ended December 31, 2012) which are incorporated by reference in this filing.	
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101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	

I&M‡ File No. 1-3570

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
3(a)	Composite of the Amended Articles of Acceptance of I&M, dated of March 7, 1997.	1996 Form 10-K, Ex 3(c)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
3(b)	Composite By-Laws of I&M, amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)
4(a)	Indenture (for unsecured debt securities), dated as of October 1, 1998, between I&M and The Bank of New York, as Trustee.	Registration Statement No. 333-88523, Ex 4(a)(b)(c) Registration Statement No. 333-58656, Ex 4(b)(c) Registration Statement No. 333-108975, Ex 4(b)(c)(d) Registration Statement No. 333-136538, Ex 4(b)(c) Registration Statement No. 333-156182, Ex 4(b) Registration Statement No. 333-185087, Ex 4(b)
10(a)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a) Registration Statement No. 2-63234, Ex 5(a)(1)(B) Registration Statement No. 2-66301, Ex 5(a)(1)(C) Registration Statement No. 2-67728, Ex 5(a)(1)(D) APCo 1989 Form 10-K, Ex 10(a)(1)(F), File No. 1-3457 APCo 1992 Form 10-K, Ex 10(a)(1)(B), File No. 1-3457
10(a)(1)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended, March 13, 2006.	2005 Form 10-K, Ex 10(a)(2)
10(a)(2)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.	Registration Statement No. 2-60015, Ex 5(e)
10(a)(3)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended.	Registration Statement No. 2-60015, Ex 5(c) Registration Statement No. 2-67728, Ex 5(a)(3)(B) APCo 1992 Form 10-K, Ex 10(a)(2)(B), File No. 1-3457
10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M, and OPCo and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a) Registration Statement No. 2-61009, Ex 5(b) 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525
10(b)(1)	Unit Power Agreement dated as of March 31, 1982 between AEGCo and I&M, as amended.	Registration Statement No. 33-32752, Ex 28(b)(1)(A)(B)
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	1985 Form 10-K, Ex 10(b), File No. 1-3525 1988 Form 10-K, File No. 1-3525, Ex 10(b)(2)
10(d)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, KGPCo and WPCo.	2004 Form 10-K, Ex 10(d)(1)
10(d)(1)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(d)(2)
10(d)(2)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, KGPCo and WPCo.	2004 Form 10-K, Ex 10(d)(3)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	1996 Form 10-K, Ex 10(l), File No. 1-3525
10(f)	Consent Decree with U.S. District Court.	Form 8-K, Ex 10.1 dated October 9, 2007
10(g)	Lease Agreements, dated as of December 1, 1989, between I&M and Wilmington Trust Company, as amended.	Registration Statement No. 33-32753, Ex 28(a)(1-6)(C) 1993 Form 10-K, Ex 10(e)(1-6)(B)
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the I&M 2012 Annual Report (for the fiscal year ended December 31, 2012) which are incorporated by reference in this filing.	
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
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101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
OPCo‡ File No.1-6543		
3(a)	Composite of the Amended Articles of Incorporation of OPCo, dated June 3, 2002.	Form 10-Q, Ex 3(e), June 30, 2002

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
3(b)	Amended Code of Regulations of OPCo.	Form 10-Q, Ex 3(b), June 30, 2008
3(c)	Agreement and Plan of Merger of Ohio Power Company and Columbus Southern Power Company entered into as of December 31, 2012.	Form 8-K, Ex 2.1 dated January 6, 2012
4(a)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between OPCo and Bankers Trust Company (now Deutsche Bank Trust Company Americas), as Trustee.	Registration Statement No. 333-49595, Ex 4(a)(b)(c) Registration Statement No. 333-106242, Ex 4(b)(c)(d) Registration Statement No. 333-75783, Ex 4(b)(c) Registration Statement No. 333-127913, Ex 4(b)(c) Registration Statement No. 333-139802, Ex 4(a)(b)(c) Registration Statement No. 333-139802, Ex 4(b)(c)(d) Registration Statement No. 333-161537, Ex 4(b)(c)(d)
4(b)	Company Order and Officer's Certificate to Deutsche Bank Trust Company Americas, dated September 24, 2009, establishing terms of 5.375% Senior Notes, Series M due 2021.	Form 8-K, Ex 4(a) dated September 24, 2009
4(c)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between OPCo and Bank One, N.A., as Trustee.	Registration Statement No. 333-127913, Ex 4(d)(e)(f)
4(d)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between CSPCo (predecessor in interest to OPCo) and Bankers Trust Company, as Trustee.	Registration Statement No. 333-54025, Ex 4(a)(b)(c)(d) Registration Statement No. 333-128174, Ex 4(b)(c)(d) Registration Statement No. 333-150603. Ex 4(b)
4(e)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between CSPCo (predecessor in interest to OPCo) and Bank One, N.A., as Trustee.	Registration Statement No. 333-128174, Ex 4(e)(f)(g) Registration Statement No. 333-150603 Ex 4(b)
4(f)	First Supplemental Indenture, dated as of December 31, 2012, by and between OPCo and Deutsche Bank Trust Company Americas, as trustee, supplementing the Indenture dated as of September 1, 1997 between CSPCo (predecessor in interest to OPCo) and the trustee.	Form 8-K, Ex 4.1 dated January 6, 2012
4(g)	Third Supplemental Indenture, dated as of December 31, 2012, by and between OPCo and The Bank of New York Mellon Trust Company, N.A., as trustee, supplementing the Indenture dated as of February 14, 2003 between CSPCo (predecessor in interest to OPCo) and the trustee.	Form 8-K, Ex 4.2 dated January 6, 2012
4(h)	CSPCo (predecessor in interest to OPCo) Company Order and Officer's Certificate to Deutsche Bank Trust Company Americas, dated May 16, 2008, establishing terms of 6.05% Senior Notes, Series G, due 2018.	Form 8-K, Ex 4(a), dated May 16, 2008

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
10(a)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a) Registration Statement No. 2-63234, Ex 5(a)(1)(B) Registration Statement No. 2-66301, Ex 5(a)(1)(C) Registration Statement No. 2-67728, Ex 5(a)(1)(B) APCo 1989 Form 10-K, Ex 10(a)(1)(F), File No. 1-3457 APCo 1992 Form 10-K, Ex 10(a)(1)(B), File No.1-3457
10(a)(1)	Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended March 13, 2006.	2005 Form 10-K, Ex 10(a)(2)
10(a)(2)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.	Registration Statement No. 2-60015, Ex 5(e)
10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M and OPCo and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a) Registration Statement No. 2-61009, Ex 5(b) 1990 Form 10-K, Ex 10(a)(3), File 1-3525
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent.	1985 Form 10-K, Ex 10(b), File No. 1-3525 1988 Form 10-K, Ex 10(b)(2), File No. 1-3525
10(d)	Unit Power Agreement, dated March 15, 2007 between AEGCo and CSPCo (predecessor in interest to OPCo).	2007 Form 10-K, Ex 10(b)(2)
10(e)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, KGPCo and WPCo.	2004 Form 10-K, Ex 10(d)(1)
10(f)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(d)(2)
10(g)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, KGPCo and WPCo.	2004 Form 10-K, Ex 10(d)(3)
10(h)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	1996 Form 10-K, Ex 10(l), File No. 1-3525
10(i)	Consent Decree with U.S. District Court.	Form 8-K, Item Ex 10.1 dated October 9, 2007
10(i)(1)	Amendment No. 9, dated July 1, 2003, to Station Agreement dated January 1, 1968, among OPCo, Buckeye and Cardinal Operating Company, and amendments thereto.	Form 10-Q, Ex 10(a), September 30, 2004
10(j)	Amendment No. 1, dated October 1, 1973, to Station Agreement dated January 1, 1968, among OPCo, Buckeye and Cardinal Operating Company, and amendments thereto.	1993 Form 10-K, Ex 10(f) 2003 Form 10-K, Ex 10(e)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the OPCo 2012 Annual Report (for the fiscal year ended December 31, 2012) which are incorporated by reference in this filing.	
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
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*95	Mine Safety Disclosure.	
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101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
PSO‡ File No. 0-343		
3(a)	Certificate of Amendment to Restated Certificate of Incorporation of PSO.	Form 10-Q, Ex 3(a), June 30, 2008
3(b)	Composite By-Laws of PSO amended as of February 26, 2008.	2007 Form 10-K, Ex 3 (b)
4(a)	Indenture (for unsecured debt securities), dated as of November 1, 2000, between PSO and The Bank of New York, as Trustee.	Registration Statement No. 333-100623, Ex 4(a)(b) Registration Statement No. 333-114665, Ex 4(b)(c) Registration Statement No. 333-133548, Ex 4(b)(c) Registration Statement No. 333-156319, Ex 4(b)(c)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(b)	Eighth Supplemental Indenture, dated as of November 13, 2009 between PSO and The Bank of New York Mellon, as Trustee, establishing terms of the 5.15% Senior Notes, Series H, due 2019.	Form 8-K, Ex 4(a), dated November 13, 2009
4(c)	Ninth Supplemental Indenture, dated as of January 19, 2011 between PSO and The Bank of New York Mellon Trust Company, N.A., as Trustee, establishing terms of 4.40% Senior Notes, Series I, due 2021.	Form 8-K, Ex 4(a) dated January 20, 2011
10(a)	Restated and Amended Operating Agreement, among PSO, SWEPCo and AEPSC, Issued on February 10, 2006, Effective May 1, 2006.	Form 10-Q, Ex 10(a), March 31, 2006
*10(b)	Third Restated and Amended Transmission Coordination Agreement Between PSO, SWEPCo and AEPSC dated February 18, 2011.	
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the PSO 2012 Annual Report (for the fiscal year ended December 31, 2012) which are incorporated by reference in this filing.	
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
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Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
SWEPCo‡ File No. 1-3146		
3(a)	Composite of Amended Restated Certificate of Incorporation of SWEPCo.	2008 Form 10-K, Ex 3(a)
3(b)	Composite By-Laws of SWEPCo amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)
4(a)	Indenture (for unsecured debt securities), dated as of February 4, 2000, between SWEPCo and The Bank of New York, as Trustee.	Registration Statement No. 333-96213 Registration Statement No. 333-87834, Ex 4(a)(b) Registration Statement No. 333-100632, Ex 4(b) Registration Statement No. 333-108045, Ex 4(b) Registration Statement No. 333-145669, Ex 4(c)(d) Registration Statement No. 333-161539, Ex 4(b)(c)
4(b)	Eighth Supplemental Indenture dated as of March 1, 2010 between SWEPCo and The Bank of New York Mellon establishing terms of 6.20% Senior Notes, Series H, due 2040.	Form 8-K, Ex 4(a), dated March 8, 2010
4(c)	Ninth Supplemental Indenture dated as of February 1, 2012 between SWEPCo and The Bank of New York Mellon Trust Company, N.A. establishing terms of 3.55% Senior Notes, Series I, due 2022.	Form 8-K, Ex 4(a), dated February 3, 2012
10(a)	Restated and Amended Operating Agreement, among PSO, TCC, TNC, SWEPCo and AEPSC, Issued on February 10, 2006, Effective May 1, 2006.	Form 10-Q, Ex 10(a), March 31, 2006
*10(b)	Third Restated and Amended Transmission Coordination Agreement Between PSO, SWEPCo and AEPSC dated February 18, 2011.	
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the SWEPCo 2012 Annual Report (for the fiscal year ended December 31, 2012) which are incorporated by reference in this filing.	
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
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‡ Certain instruments defining the rights of holders of long-term debt of the registrants included in the financial statements of registrants filed herewith have been omitted because the total amount of securities authorized thereunder does not exceed 10% of the total assets of registrants. The registrants hereby agree to furnish a copy of any such omitted instrument to the SEC upon request.

2012 Annual Reports

American Electric Power Company, Inc. and Subsidiary Companies

Appalachian Power Company and Subsidiaries

Indiana Michigan Power Company and Subsidiaries

Ohio Power Company and Subsidiary

Public Service Company of Oklahoma

Southwestern Electric Power Company Consolidated

Audited Financial Statements and
Management's Discussion and Analysis of Financial Condition and Results of Operations

AMERICAN ELECTRIC POWER

AEP: America's Energy Partner®

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF ANNUAL REPORTS

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., an electric utility holding company.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States. BlueStar began doing business as AEP Energy, Inc. in June 2012.
AEPGenCo	AEP Generation Resources Inc., a nonregulated AEP subsidiary in the Generation and Marketing segment.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West Companies	PSO, SWEPCo, TCC and TNC.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, asset management and commercial and industrial sales in the deregulated Texas market.
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.
APSC	Arkansas Public Service Commission.
BlueStar	BlueStar Energy Holdings, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States. BlueStar began doing business as AEP Energy, Inc. in June 2012.
BOA	Bank of America Corporation.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
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.
CRES	Competitive Retail Electric Service.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
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, DCC Fuel IV LLC and DCC Fuel V LLC, consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.

Term	Meaning
E&R	Environmental compliance and transmission and distribution system reliability.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
ENEC	Expanded Net Energy Charge.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments.
ETA	Electric Transmission America, LLC an equity interest joint venture with MidAmerican Energy Holdings Company America Transco, LLC formed to own and operate electric transmission facilities in North America outside of ERCOT.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP and MidAmerican Energy Holdings Company Texas Transco, LLC formed to own and operate electric transmission facilities in ERCOT.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
IEU	Industrial Energy Users-Ohio.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
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.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWh	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate transactions among members of the Interconnection Agreement.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
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.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NSR	New Source Review.
OATT	Open Access Transmission Tariff.

Term	Meaning
OCC	Corporation Commission of the State of Oklahoma.
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.
PM	Particulate Matter.
POLR	Provider of Last Resort revenues.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, I&M, OPCo, PSO and SWEPCo.
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 1,310 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.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity for AEP and SWEPCo.
SEET	Significantly Excessive Earnings Test.
SEC	U.S. Securities and Exchange Commission.
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.
SSO	Standard service offer.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant, a 543 MW natural gas unit owned by SWEPCo.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Transition Funding	AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas restructuring law.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW pulverized coal ultra-supercritical generating unit in Arkansas that is 73% owned by SWEPCo.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations," but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue" and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, we undertake no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- The economic climate, growth or contraction within and changes in market demand and demographic patterns in our service territory.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load, customer growth and the impact of retail competition, particularly in Ohio.
- Weather conditions, including storms and drought conditions, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generating capacity and the performance of our generating plants.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity and transmission lines and facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation, including oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants and related assets.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.
- A reduction in the federal statutory tax rate could result in an accelerated return of deferred federal income taxes to customers.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance.
- Resolution of litigation.
- Our ability to constrain operation and maintenance costs.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, coal, natural gas and other energy-related commodities.
- Prices and demand for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Our ability to recover through rates or market prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.
- Volatility and changes in markets for electricity, coal, natural gas and other energy-related commodities.

- Changes in utility regulation, including the implementation of ESPs and the transition to market and expected legal separation for generation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP.
- Our ability to successfully manage negotiations with stakeholders and obtain regulatory approval to terminate the Interconnection Agreement.
- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of our debt.
- The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

The forward looking statements of AEP and its Registrant Subsidiaries speak only as of the date of this report or as of the date they are made. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information. For a more detailed discussion of these factors, see "Risk Factors" in Part I of this report.

AEP COMMON STOCK AND DIVIDEND INFORMATION

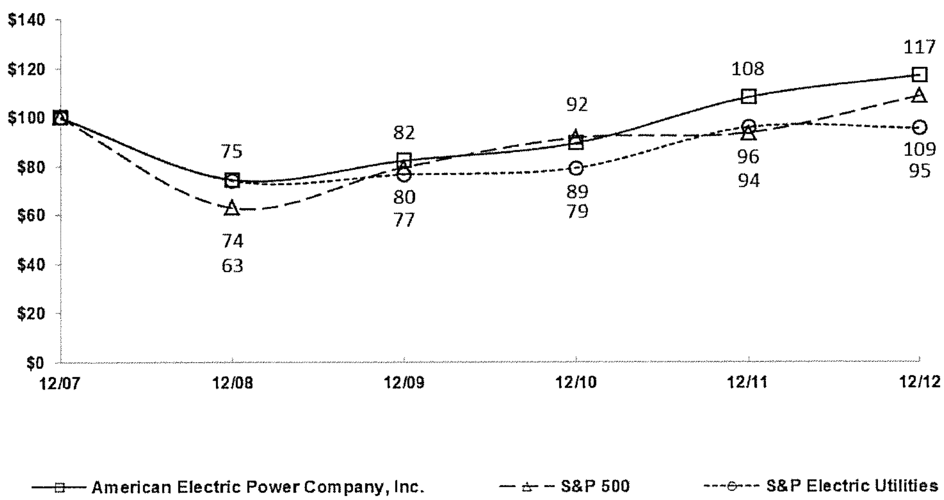
The AEP common stock quarterly high and low sales prices, quarter-end closing price and the cash dividends paid per share are shown in the following table:

Quarter Ended	High	Low	Quarter-End Closing Price	Dividend
December 31, 2012	$ 45.41	$ 40.56	$ 42.68	$ 0.47
September 30, 2012	44.84	39.62	43.94	0.47
June 30, 2012	40.46	36.97	39.90	0.47
March 31, 2012	41.98	37.46	38.58	0.47
December 31, 2011	$ 41.71	$ 35.85	$ 41.31	$ 0.47
September 30, 2011	38.98	33.09	38.02	0.46
June 30, 2011	38.99	34.37	37.68	0.46
March 31, 2011	36.92	33.47	35.14	0.46

AEP common stock is traded principally on the New York Stock Exchange. As of December 31, 2012, AEP had approximately 83,000 registered shareholders.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among American Electric Power Company, Inc., the S&P 500 Index, and the S&P Electric Utilities Index



*$100 invested on 12/31/07 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SELECTED CONSOLIDATED FINANCIAL DATA

	2012	2011	2010	2009	2008
	(dollars in millions, except per share amounts)				
STATEMENTS OF INCOME DATA					
Total Revenues	$ 14,945	$ 15,116	$ 14,427	$ 13,489	$ 14,440
Operating Income	$ 2,656	$ 2,782	$ 2,663	$ 2,771	$ 2,787
Income Before Discontinued Operations and Extraordinary Items	$ 1,262	$ 1,576	$ 1,218	$ 1,370	$ 1,376
Discontinued Operations, Net of Tax	-	-	-	-	12
Income Before Extraordinary Items	1,262	1,576	1,218	1,370	1,388
Extraordinary Items, Net of Tax	-	373	-	(5)	-
Net Income	1,262	1,949	1,218	1,365	1,388
Net Income Attributable to Noncontrolling Interests	3	3	4	5	5
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,259	1,946	1,214	1,360	1,383
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	5	3	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,259	$ 1,941	$ 1,211	$ 1,357	$ 1,380
BALANCE SHEETS DATA					
Total Property, Plant and Equipment	$ 57,454	$ 55,670	$ 53,740	$ 51,684	$ 49,710
Accumulated Depreciation and Amortization	18,691	18,699	18,066	17,340	16,723
Total Property, Plant and Equipment – Net	$ 38,763	$ 36,971	$ 35,674	$ 34,344	$ 32,987
Total Assets	$ 54,367	$ 52,223	$ 50,455	$ 48,348	$ 45,155
Total AEP Common Shareholders' Equity	$ 15,237	$ 14,664	$ 13,622	$ 13,140	$ 10,693
Noncontrolling Interests	$ -	$ 1	$ -	$ -	$ 17
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ -	$ -	$ 60	$ 61	$ 61
Long-term Debt (a)	$ 17,757	$ 16,516	$ 16,811	$ 17,498	$ 15,983
Obligations Under Capital Leases (a)	$ 449	$ 458	$ 474 (b)	$ 317	$ 325
AEP COMMON STOCK DATA					
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:					
Income Before Discontinued Operations and Extraordinary Items	$ 2.60	$ 3.25	$ 2.53	$ 2.97	$ 3.40
Discontinued Operations, Net of Tax	-	-	-	-	0.03
Income Before Extraordinary Items	2.60	3.25	2.53	2.97	3.43
Extraordinary Items, Net of Tax	-	0.77	-	(0.01)	-
Total Basic Earnings per Share Attributable to AEP Common Shareholders	$ 2.60	$ 4.02	$ 2.53	$ 2.96	$ 3.43
Weighted Average Number of Basic Shares Outstanding (in millions)	485	482	479	459	402
Market Price Range:					
High	$ 45.41	$ 41.71	$ 37.94	$ 36.51	$ 49.11
Low	$ 36.97	$ 33.09	$ 28.17	$ 24.00	$ 25.54
Year-end Market Price	$ 42.68	$ 41.31	$ 35.98	$ 34.79	$ 33.28
Cash Dividends Declared per AEP Common Share	$ 1.88	$ 1.85	$ 1.71	$ 1.64	$ 1.64
Dividend Payout Ratio	72.31%	46.02%	67.59%	55.41%	47.8%
Book Value per AEP Common Share	$ 31.35	$ 30.36	$ 28.32	$ 27.49	$ 26.35

(a) Includes portion due within one year.
(b) Obligations Under Capital Leases increased primarily due to capital leases under new master lease agreements for property that was previously leased under operating leases.

**AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**

EXECUTIVE OVERVIEW

Company Overview

American Electric Power Company, Inc. (AEP) is one of the largest investor-owned electric public utility holding companies in the United States. Our electric utility operating companies provide generation, transmission and distribution services to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

Our subsidiaries operate an extensive portfolio of assets including:

- Almost 37,600 megawatts of generating capacity, one of the largest complements of generation in the United States.
- Approximately 40,000 miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern United States.
- Approximately 221,000 miles of distribution lines that deliver electricity to 5.3 million customers.
- Substantial commodity transportation assets (more than 7,600 railcars, approximately 3,100 barges, 60 towboats, 25 harbor boats and a coal handling terminal with approximately 18 million tons of annual capacity). Our commercial barging operations annually transport approximately 42 million tons of coal and dry bulk commodities. Approximately 38% of the barging is for transportation of agricultural products, 30% for coal, 18% for steel and 14% for other commodities.

Turk Plant

SWEPCo constructed the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which was placed into service in December 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and operates the completed facility. See the "Turk Plant" section of Note 3.

Sustainable Cost Reductions

In April 2012, we initiated a process to identify strategic repositioning opportunities and efficiencies that will result in sustainable cost savings. We selected a consulting firm to conduct an organizational and process optimization evaluation and a second firm to evaluate our current employee benefit programs. We recorded a charge to expense of $47 million ($30 million, net of tax) in 2012 related primarily to severance benefits. We expect to complete the final phase of the sustainable cost reduction program by the end of the first quarter of 2013. Going forward, we anticipate that this program provides a behavioral foundation upon which additional process improvement projects will be implemented as a regular business practice. At this time, we are unable to estimate the total amount to be incurred in future periods related to this initiative or to quantify the effects on future earnings, cash flows and financial condition.

Retiree Medical Contribution Changes

In November 2012, we announced changes to our retiree medical coverage. Effective for retirements after December 2012, our contribution to retiree medical coverage will be capped reducing our exposure to future medical cost inflation. Effective for employees hired after December 2013, we will not provide retiree medical coverage. For 2013, we estimate these changes will result in a decrease of Other Operation and Maintenance expenses of approximately $80 million.

Financing Changes

In December 2012, we retired $558 million of Parent debt with part of the proceeds of an issuance of $850 million of Senior Unsecured Notes. Expenses associated with the early retirement of debt were approximately $50 million in 2012 with annual savings of approximately $30 million per year in 2013 and 2014.

In February 2013, we increased and extended the $1.5 billion credit facility due in June 2015 to $1.75 billion due in June 2016, extended the $1.75 billion credit facility due in July 2016 to July 2017 and issued a $1 billion interim credit facility due in May 2015 to fund certain OPCo maturities.

Ohio Plant Impairments

In October 2012, we filed applications with the FERC proposing to terminate the Interconnection Agreement and complete the corporate separation of OPCo's generation assets. Based on the intention to terminate the Interconnection Agreement, we performed an evaluation of the recoverability of generation assets using generating unit specific estimated future cash flows and concluded that OPCo had a material impairment of certain generation assets. In the fourth quarter of 2012, OPCo recorded a pretax impairment of $287 million ($185 million, net of tax) in Asset Impairments and Other Related Charges on the statement of income related to Beckjord Plant Unit 6, Conesville Plant Unit 3, Kammer Plant Units 1-3, Muskingum River Plant Units 1-4, Sporn Plant Units 2 and 4 and Picway Plant Unit 5 generating units and related material and supplies inventory.

Corporate Separation, Plant Transfers and Termination of Interconnection Agreement

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo's generation assets including the transfer of OPCo's generation assets at net book value to AEPGenCo. AEPGenCo will also assume the associated generation liabilities. In December 2012, the PUCO granted the IEU and the Ohio Consumers' Counsel requests for rehearing for the purpose of further consideration and those requests remain pending.

Also in October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generation assets from its distribution and transmission operations. The filings requested approval to transfer at net book value approximately 9,200 MW of OPCo-owned generation assets to AEPGenCo. The AEP East Companies also requested FERC approval to transfer at net book value OPCo's current two-thirds ownership (867 MW) in Amos Plant, Unit 3 to APCo and transfer at net book value OPCo's Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each). Additionally, the AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate their respective power supply resources. Under the PCA, APCo, I&M and KPCo would be individually responsible for planning their respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo, I&M and KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities. Intervenors have opposed several of these filings. The AEP East Companies have responded and continue to pursue approvals from the FERC. A decision from the FERC is expected in mid-2013.

In December 2012, APCo and WPCo filed requests with the Virginia SCC and the WVPSC for approval of the Amos Plant and Mitchell Plant transfers discussed above. Hearings at the Virginia SCC and the WVPSC are scheduled for April 2013 and July 2013, respectively. If the transfers are approved, APCo and WPCo anticipate seeking cost recovery when they file their next base rate cases.

Also in December 2012, KPCo filed a request with the KPSC for approval of the Mitchell Plant transfer discussed above. If the transfer is approved, KPCo anticipates seeking cost recovery when filing its next base rate case. In addition, KPCo announced its plan to retire Big Sandy Plant, Unit 2 in early 2015 and its intention to study the conversion of Big Sandy Plant, Unit 1 to burn natural gas instead of coal.

Our results of operations related to generation in Ohio will be largely determined by prevailing market conditions.

June 2012 – May 2015 Ohio ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP through May 2015. The ESP allowed the continuation of the fuel adjustment clause, adopted a 12% earnings threshold for the SEET and established a non-bypassable Distribution Investment Rider (DIR) effective September 2012 through May 2015 to recover, with certain caps, post-August 2010 distribution investment. The DIR is capped at $86 million in 2012, $104 million in 2013, $124 million in 2014 and $52 million for the period January through May 2015, for a total of $366 million. The ESP also maintained recovery of several previous ESP riders and required OPCo to contribute $2 million per year during the ESP to the Ohio Growth Fund. In addition, the PUCO approved a storm damage recovery mechanism.

As part of the ESP decision, the PUCO ordered OPCo to conduct an energy-only auction for 10% of the SSO load with delivery beginning six months after the receipt of final orders in both the ESP and corporate separation cases and extending through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 50% of the SSO load with delivery beginning June 2014 through May 2015 and for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. OPCo will conduct energy and capacity auctions for its entire SSO load for delivery starting in June 2015.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The RPM price is approximately $20/MW day through May 2013. As part of the August 2012 PUCO ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is intended to provide approximately $500 million over the ESP period and will be collected from customers at $3.50/MWh through May 2014 and $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the deferred capacity costs. As of December 31, 2012, OPCo recorded $66 million of incurred deferred capacity costs, including debt carrying costs, in Regulatory Assets on the balance sheet. The capacity order, including collection of capacity costs, has been appealed to the Supreme Court of Ohio.

In January 2013, the PUCO issued its Order on Rehearing for the ESP which generally upheld its August 2012 order including the implementation of the RSR. The PUCO clarified that a final reconciliation of revenues and costs would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket. If OPCo is ultimately not permitted to fully collect its deferred capacity costs and ESP rates, including the RSR, it would reduce future net income and cash flows and impact financial condition. See "Ohio Electric Security Plan Filing" section of Note 3.

Ohio Customer Choice

In our Ohio service territory, various CRES providers are targeting retail customers by offering alternative generation service. As a result, we lost approximately $235 million of gross margin in 2012 as compared to 2011. This reduction in gross margin is partially offset by (a) collection of capacity revenues from CRES providers, (b) off-system sales, (c) deferral of unrecovered capacity costs, (d) Retail Stability Rider collections and (e) revenues from AEP Energy. AEP Energy is our CRES provider and part of our Generation and Marketing segment which targets retail customers, both within and outside of our retail service territory. As of December 31, 2012, based upon an average annual load, approximately 51% of our Ohio load had switched to CRES providers.

Customer Demand

In comparison to 2011, cooling degree days in 2012 were down 6% in our western region and up 4% in our eastern region. Heating degree days in 2012 were down in our western and eastern regions by 36% and 15%, respectively. Our weather-normalized retail sales were down 0.7% compared to 2011. Our industrial sales declined 0.9% partially due to Ormet, a large aluminum company that lowered their production in the third quarter of 2012 by one-third. In February 2013, Ormet filed Chapter 11 bankruptcy proceedings in the state of Delaware.

In 2013, we anticipate slight increases in retail sales in our eastern region related to shale gas development and processing and in our western region related to oil and gas extraction. We also anticipate decreases in industrial demand in our eastern region related to Ormet's lower production levels discussed above.

Significantly Excessive Earnings Test

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. In the fourth quarter of 2012, the Supreme Court of Ohio upheld the PUCO decision on the 2009 SEET filing. Subsequent testimony and legal briefs from intervenors recommended refunds of a portion of 2010 earnings. OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO ordered SEET refund. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo and in 2012 for OPCo. See "Ohio Electric Security Plan Filing" section of Note 3.

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 $149 million net annual increase reflects an increase in base rates of $178 million offset by proposed corresponding reductions of $13 million to the off-system sales sharing rider, $9 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The request included an increase in depreciation rates that would result in an increase of approximately $25 million in annual depreciation expense. Included in the depreciation rates increase was a decrease in the average remaining life of Tanners Creek Plant to account for the acceleration of the retirement date of Tanners Creek Plant, Units 1-3. I&M filed rebuttal testimony in May 2012 which supported an increase of $170 million in base rates, excluding reductions to certain riders.

In February 2013, the IURC issued an order that granted an $85 million annual increase in base rates based upon a return on common equity of 10.2%, effective March 2013. The $85 million annual increase in base rates will be offset by corresponding reductions of $5 million to the off-system sales sharing rider, $11 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The IURC granted the requested increase in depreciation rates, modified the shareholder's portion of off-system sales margins to 50% below and above the $27 million imbedded in base rates, established a capacity tracker and established a major storm damage restoration reserve. See "2011 Indiana Base Rate Case" section of Note 3.

Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates by $83 million, primarily due to the Turk Plant, based upon an 11.25% return on common equity to be effective January 2013. The requested base rate increase included a return on and of the Texas jurisdictional share (approximately 33%) of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operation and maintenance costs. In September 2012, an Administrative Law Judge issued an order that granted the establishment of SWEPCo's existing rates as temporary rates beginning in late January 2013, subject to true-up to the final PUCT-approved rates. In December 2012, several intervenors filed opposing testimony with various recommendations. A decision from the PUCT is expected in the second quarter of 2013. See "2012 Texas Base Rate Case" section of Note 3.

Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share (approximately 29%) of the Turk Plant. In February 2013, a settlement was filed and a hearing was conducted. The settlement provided that SWEPCo would increase Louisiana total rates by approximately $2 million annually, effective March 2013, consisting of an increase in base rates of approximately $85 million annually offset by a decrease in fuel rates of approximately $83 million annually. The proposed March 2013 base rates are based on a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund based on the staff review of the cost of service and prudence review of the Turk Plant to be initiated by SWEPCo no later than May 2013. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover all non-fuel Turk Plant costs and a full weighted-average cost of capital return on the Turk Plant portion of rate base beginning January 2013. A decision from the LPSC is expected in the first quarter of 2013.

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 a fire on the electric generator. Repair of the property damage and replacement of the turbine rotors and other equipment cost approximately $400 million. In February 2013, we signed an agreement and received payment from NEIL, the insurer, to settle the remaining claims. The settlement did not have a material impact on net income, cash flows or financial condition. See "Cook Plant, Unit 1 Fire and Shutdown" section of Note 5.

Cook Plant Life Cycle Management Project

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its licensed life. The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. In Indiana, I&M requested recovery of certain project costs, including interest, through a new rider effective January 2013. In Michigan, I&M requested that the MPSC approve a Certificate of Need and authorize I&M to defer, on an interim basis, incremental depreciation and related property tax costs, including interest, along with study, analysis and development costs until the applicable LCM costs are included in I&M's base rates. As of December 31, 2012, I&M has incurred $176 million related to the LCM Project, including AFUDC. Several intervenors filed testimony in Indiana with various recommendations including caps on expenditures. The IURC held a hearing in January 2013.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project with total costs of $851 million (Michigan jurisdictional share is approximately 15%) for the period 2013 through 2018. The order provided that depreciation, property taxes and a return using the overall rate of return approved in I&M's last Michigan base rate case related to the 2013 through 2018 LCM Project costs can be deferred until these costs are included in rates. The order excluded from the CON $176 million of LCM costs spent prior to 2013 as $39 million was included in the determination of Michigan base rates, effective April 2012, and the remaining $137 million in CWIP will be requested in a future base rate case. The order also excluded $142 million of future LCM costs, which if incurred, will be requested in a future base rate case. Under Michigan law, the approved CON amount is eligible for a cost increase allowance of 10%, up to $85 million, of the approved project costs in the event project costs exceed the approved level of costs.

If I&M is not ultimately permitted to recover its LCM Project costs, it would reduce future net income and cash flows and impact financial condition. See "Cook Plant Life Cycle Management Project" section of Note 3.

LITIGATION

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. We assess the probability of loss for each contingency and accrue a liability for cases that have a probable likelihood of loss if the loss can be estimated. For details on our regulatory proceedings and pending litigation see Note 3 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

ENVIRONMENTAL ISSUES

We are implementing a substantial capital investment program and incurring additional operational costs to comply with environmental control requirements. We will need to make additional investments and operational changes in response to existing and anticipated requirements such as CAA requirements to reduce emissions of SO_2, NO_x, PM and hazardous air pollutants (HAPs) from fossil fuel-fired power plants, new proposals governing the beneficial use and disposal of coal combustion products and proposed clean water rules.

We are engaged in litigation about environmental issues, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of SNF and future decommissioning of our nuclear units. We, along with various industry groups, affected states and other parties have challenged some of the Federal EPA requirements in court. We are also engaged in the development of possible future requirements including the items discussed below and reductions of CO_2 emissions to address concerns about global climate change. We believe that further analysis and better coordination of these environmental requirements would facilitate planning and lower overall compliance costs while achieving the same environmental goals.

We will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. Recovery in Ohio will be dependent upon prevailing market conditions. If we are unable to recover the costs of environmental compliance, it would reduce future net income and cash flows and impact financial condition.

Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed in the next several sections will have a material impact on the generating units in the AEP System. We continue to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of December 31, 2012, the AEP System had a total generating capacity of nearly 37,600 MWs, of which over 23,700 MWs are coal-fired. We continue to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on our coal-fired generating facilities. Based upon our estimates, investment to meet these proposed requirements ranges from approximately $4 billion to $5 billion between 2012 and 2020. These amounts include investments to convert 1,555 MWs of coal generation to natural gas capacity. If natural gas conversion is not completed, these units could be retired sooner than planned.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in the final rules. The cost estimates will also change based on: (a) the states' implementation of these regulatory programs, including the potential for state implementation plans or federal implementation plans that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on our units, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity and (g) other factors.

Subject to the factors listed above and based upon our continuing evaluation, we have given notice to the applicable RTOs of our intent to retire the following plants or units of plants before or during 2016:

Company	Plant Name and Unit	Generating Capacity (in MWs)
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
APCo/OPCo	Philip Sporn Plant, Units 1-4	600
I&M	Tanners Creek Plant, Units 1-3	495
KPCo	Big Sandy Plant, Unit 1	278
OPCo	Kammer Plant	630
OPCo	Muskingum River Plant, Units 1-4	840
OPCo	Picway Plant	100
SWEPCo	Welsh Plant, Unit 2	528
Total		4,441

Duke Energy Corporation, the operator of W. C. Beckjord Generating Station, has announced its intent to close the facility in 2015. OPCo owns 12.5% (53 MWs) of one unit at that station.

KPCo notified the KPSC of its plan to retire Big Sandy Plant, Unit 2 in early 2015 and its intention to study the conversion of Big Sandy Plant, Unit 1 to burn natural gas instead of coal.

In September 2012, based upon an agreement in principle with the Federal EPA, the State of Oklahoma and other parties, PSO filed an environmental compliance plan with the OCC to retire Units 3 and 4 of the Northeastern Station, a total of 930 MWs, in 2026 and 2016, respectively. See "Oklahoma Environmental Compliance Plan" and "Regional Haze" sections below.

In December 2012, we retired OPCo's 165 MW Conesville Plant, Unit 3.

A decline in natural gas prices, pending environmental rules and the proposed termination of the Interconnection Agreement had an adverse impact on the recoverability of the net book values of certain coal-fired units. In 2012, we recorded a $287 million pretax impairment charge for OPCo's net book value of certain plants totaling 1,870 MWs in the table above and the Beckjord and Conesville plants discussed above. See "Impairments" section of Note 6.

We are still evaluating our plans for and the timing of conversion of some of our coal units to natural gas, installing emission control equipment on other units and closure of existing units based on changes in emission requirements and demand for power. To the extent existing generation assets and the cost of new equipment and converted facilities are not recoverable, it could reduce future net income and cash flows.

Modification of the NSR Litigation Consent Decree

In 2007, the U.S. District Court for the Southern District of Ohio approved a consent decree between AEP subsidiaries in the eastern area of the AEP System and the Department of Justice, the Federal EPA, eight northeastern states and other interested parties to settle all claims that the AEP subsidiaries violated the NSR provisions of the CAA when they undertook various equipment repair and replacement projects over a period of nearly 20 years. The consent decree's terms include installation of environmental control equipment on certain generating units, a declining cap on SO_2 and NO_x emissions from the AEP System and various mitigation projects.

The consent decree requires certain types of control equipment to be installed at Muskingum River Plant, Unit 5 and Big Sandy Plant, Unit 2 in 2015 and the two units of the Rockport Plant in 2017 and 2019. In February 2013, an agreement to modify the consent decree was reached and filed with the court. The terms of the modification include more options for the affected units (including alternative control technologies, re-fueling and/or retirement), more stringent SO_2 emission caps for the AEP System and additional mitigation measures. The Federal EPA will seek public comments on the modification prior to its entry by the court. Under the terms of the modification, the units of Rockport Plant will be equipped with dry sorbent injection systems in 2015 and have options to retrofit additional SO_2 controls, refuel, repower or retire in 2025 and 2028. Muskingum River Plant, Unit 5 will have options to cease burning coal and retire in 2015 or cease burning coal in 2015 and complete a refueling project no later than June 2017. Big Sandy Plant, Unit 2 will have options to retrofit, retire, repower or refuel by 2015. I&M will secure an additional 200 MWs of renewable power resources by December 2014 and provide $8.5 million for additional mitigation projects.

Rockport Plant Environmental Controls

I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit one unit at its Rockport Plant with environmental controls estimated to cost $1.4 billion to comply with new requirements. AEGCo and I&M jointly own Unit 1 and jointly lease Unit 2 of the Rockport Plant. I&M is also evaluating options related to the maturity of the lease for Rockport Plant Unit 2 in 2022 and continues to investigate alternative compliance technologies for these units as part of its overall compliance strategy. As of December 31, 2012, we have incurred $71 million related to these environmental controls, including AFUDC. If we are not ultimately permitted to recover our incurred costs, it would reduce future net income and cash flows. In February 2013, I&M filed a motion with the IURC to dismiss its request for approval of a CPCN for environmental controls after modification to the NSR consent decree. See the "Modification of the NSR Litigation Consent Decree" section above and the "Rockport Plant Environmental Controls" section of Note 3.

Big Sandy Unit 2 FGD System

In May 2012, KPCo withdrew its application to the KPSC seeking approval of a Certificate of Public Convenience and Necessity to retrofit Big Sandy Unit 2 with a dry FGD system. As part of the Mitchell Plant transfer filing discussed above under "Corporate Separation, Plant Transfers and Application to Amend Sharing Agreement", KPCo requested costs related to the FGD project be established as a regulatory asset and recovered in KPCo's next base rate case. As of December 31, 2012, KPCo has incurred $29 million related to the FGD project, which is recorded in Deferred Charges and Other Noncurrent Assets on the balance sheet. See "Big Sandy Plant, Unit 2 FGD System" section of Note 3.

Flint Creek Plant Environmental Controls

In February 2012, SWEPCo filed a petition with the APSC seeking a declaratory order to install environmental controls at the Flint Creek Plant to comply with the standards established by the CAA. The estimated cost of the project is $408 million, excluding AFUDC and company overheads. As a joint owner of the Flint Creek Plant, SWEPCo's portion of those costs is estimated at $204 million. As of December 31, 2012, SWEPCo has incurred $11 million related to this project, including AFUDC and company overheads. The APSC staff and the Sierra Club filed testimony that recommended the APSC deny the requested declaratory order. A hearing is scheduled for March 2013. If SWEPCo is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

Oklahoma Environmental Compliance Plan

In September 2012, PSO filed an environmental compliance plan with the OCC reflecting the retirement of Northeastern Station (NES) Unit 4 in 2016 and additional environmental controls on NES Unit 3 to continue operations through 2026. The plan requested approval for (a) cost recovery through base rates by 2026 of an estimated $256 million of new environmental investment that will be incurred prior to 2016 at NES Unit 3, (b) cost recovery through 2026 of NES Units 3 and 4 net book value (combined net book value of the two units is $234 million as of December 31, 2012), (c) cost recovery through base rates of an estimated $83 million of new investment incurred through 2016 at various gas units and (d) a new 15-year purchase power agreement (PPA) with a nonaffiliated entity, effective in 2016, with cost recovery through a rider, including an annual earnings component of $3 million. Although the environmental compliance plan does not seek to put any new costs into rates at this time, PSO anticipates seeking cost recovery when filing its next base rate case, which is expected to occur no later than 2014. In January 2013, several parties filed testimony with various recommendations. A hearing is scheduled for April 2013. See "Oklahoma Environmental Compliance Plan" section of Note 3.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements.

The Federal EPA issued the Clean Air Interstate Rule (CAIR) in 2005 requiring specific reductions in SO_2 and NO_x emissions from power plants. In 2008, the District of Columbia Circuit Court of Appeals issued a decision remanding CAIR to the Federal EPA. The Federal EPA issued the Cross-State Air Pollution Rule (CSAPR) (discussed in detail below) in August 2011 to replace CAIR. The CSAPR was challenged in the courts. The United States Court of Appeals for the District of Columbia Circuit issued an order in December 2011 staying the effective date of the rule pending judicial review. In August 2012, a panel of the United States Court of Appeals for the District of Columbia Circuit issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the CAIR until a replacement rule is finalized. Nearly all of the states in which our power plants are located are covered by CAIR.

The Federal EPA issued the final maximum achievable control technology (MACT) standards for coal and oil-fired power plants (discussed in detail below) in February 2012.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's requirement that certain facilities install best available retrofit technology (BART) to address regional haze in federal parks and other protected areas. BART requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through individual state implementation plans (SIPs) or, if SIPs are not adequate or are not developed on schedule, through federal implementation plans (FIPs). The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas and Oklahoma. The Federal EPA finalized a FIP for Oklahoma that contains more stringent control requirements for SO_2 emissions from affected units in that state. The Arkansas SIP was disapproved and the state is developing a revised submittal. In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the CSAPR trading programs to use those programs in place of source-specific BART for SO_2 and NO_x emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. This rule is being challenged in the United States Court of Appeals for the District of Columbia Circuit and its fate is uncertain given recent developments in the CSAPR litigation.

In 2009, the Federal EPA issued a final mandatory reporting rule for CO_2 and other greenhouse gases covering a broad range of facilities emitting in excess of 25,000 tons of CO_2 emissions per year. The Federal EPA issued a final endangerment finding for greenhouse gas emissions from new motor vehicles in 2009. The Federal EPA determined that greenhouse gas emissions from stationary sources will be subject to regulation under the CAA beginning January 2011 and finalized its proposed scheme to streamline and phase-in regulation of stationary source CO_2 emissions through the NSR prevention of significant deterioration and Title V operating permit programs through the issuance of final federal rules, SIP calls and FIPs. The Federal EPA is reconsidering whether to include CO_2 emissions in a number of stationary source standards, including standards that apply to new electric utility units and agreed to specific deadlines to issue proposed new source performance standards for utility boilers.

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for SO_2, NO_x, lead and PM, and is currently reviewing the NAAQS for ozone. States are in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the new NAAQS and may develop additional requirements for our facilities as a result of those evaluations. We cannot currently predict the nature, stringency or timing of those requirements.

Notable developments in significant CAA regulatory requirements affecting our operations are discussed in the following sections.

Cross-State Air Pollution Rule (CSAPR)

In August 2011, the Federal EPA issued CSAPR. Certain revisions to the rule were finalized in March 2012. CSAPR relies on newly-created SO_2 and NO_x allowances and individual state budgets to compel further emission reductions from electric utility generating units in 28 states. Interstate trading of allowances is allowed on a restricted sub-regional basis. Arkansas and Louisiana are subject only to the seasonal NO_x program in the rule. Texas is subject to the annual programs for SO_2 and NO_x in addition to the seasonal NO_x program. The annual SO_2 allowance budgets in Indiana, Ohio and West Virginia were reduced significantly in the rule. A supplemental rule includes Oklahoma in the seasonal NO_x program. The supplemental rule was finalized in December 2011 with an increased NO_x emission budget for the 2012 compliance year. The Federal EPA issued a final Error Corrections Rule and further CSAPR revisions in 2012 to make corrections to state budgets and unit allocations and to remove the restrictions on interstate trading in the first phase of CSAPR.

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the United States Court of Appeals for the District of Columbia Circuit. Several of the petitioners filed motions to stay the implementation of the rule pending judicial review. In December 2011, the court granted the motions for stay. In August 2012, the panel issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the CAIR until a replacement rule is finalized. The majority determined that the CAA does not allow the Federal EPA to "over control" emissions in an upwind state and that the Federal EPA exceeded its statutory authority by failing to allow states an opportunity to develop their own implementation plans before issuing a FIP. The Federal EPA and other respondents filed petitions for rehearing but in January 2013, the United States Court of Appeals for the District of Columbia Circuit denied all petitions for rehearing. Separate appeals of the supplemental rule, the Error Corrections Rule and the further revisions have been filed, but are being held in abeyance.

The time frames and stringency of the required emission reductions, coupled with the lack of robust interstate trading and the elimination of historic allowance banks, pose significant concerns for the AEP System and our electric utility customers. We cannot predict the outcome of the pending litigation.

Mercury and Other Hazardous Air Pollutants Regulation

In February 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for mercury, PM (as a surrogate for particles of nonmercury metal) and hydrogen chloride (as a surrogate for acid gases) for units burning coal on a site-wide 30-day rolling average basis. In addition, the rule proposes work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. The effective date of the final rule was April 16, 2012 and compliance is required within three years. We are participating through various organizations in the petitions for administrative reconsideration and judicial review that have been filed. In November 2012, the Federal EPA published a notice announcing that it would accept comments on its reconsideration of certain issues related to the new source standards, including clarification of the requirements that apply during periods of start-up and shut down, measurement issues and the application of variability factors that may have an impact on the level of the standards. It is uncertain whether any of the information generated during the reconsideration process will affect the standards for existing sources.

The final rule contains a slightly less stringent PM limit for existing sources than the original proposal and allows operators to exclude periods of startup and shutdown from the emissions averaging periods. The compliance time frame remains a serious concern. A one-year administrative extension may be available if the extension is necessary for the installation of controls or to avoid a serious reliability problem. In addition, the Federal EPA issued an enforcement policy describing the circumstances under which an administrative consent order might be issued to provide a fifth year for the installation of controls or completion of reliability upgrades. We are concerned about the availability of compliance extensions and the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines. We are participating in petitions for review filed in the United States Court of Appeals for the District of Columbia Circuit by several organizations of which we are members. Certain issues related to the standards for new coal-fired units have been severed from the main case and are being held in abeyance pending completion of the Federal EPA's reconsideration proceeding. The case is proceeding on the remaining issues and briefing is scheduled to be completed by April 2013.

Regional Haze

In March 2011, the Federal EPA proposed to approve in part and disapprove in part the regional haze SIP submitted by the State of Oklahoma through the Department of Environmental Quality. The Federal EPA proposed to approve all of the NO_x control measures in the SIP and disapprove the SO_2 control measures for six electric generating units, including two units owned by PSO. The Federal EPA proposed a FIP that would require these units to install technology capable of reducing SO_2 emissions to 0.06 pounds per million British thermal units within three years of the effective date of the FIP. The Federal EPA finalized the FIP in December 2011 that mirrored the proposed rule but established a five-year compliance schedule. PSO filed a petition for review of the FIP in the Tenth Circuit Court of Appeals and engaged in settlement discussions with the Federal EPA, the State of Oklahoma and other parties. In November 2012, we notified the court that the parties had reached agreement on a settlement that would provide for submission of a revised Regional Haze SIP requiring the retirement of one coal-fired unit of PSO's Northeastern Station no later than 2016, installation of emission controls on the second coal-fired Northeastern unit in 2016 and retirement of the second unit no later than 2026. Notice of the proposed settlement was published in the Federal Register in November 2012 and the comment period has closed. The Tenth Circuit Court of Appeals is holding the appeal in abeyance pending implementation of the settlement.

CO_2 Regulation

In March 2012, the Federal EPA issued a proposal to regulate CO_2 emissions from new fossil fuel-fired electricity generating units. The proposed rule establishes a new source performance standard of 1,000 pounds of CO_2 per megawatt hour of electricity generated, a rate that most natural gas combined cycle units can meet, but that is substantially below the emission rate of a new pulverized coal generator or an integrated gas combined cycle unit that uses coal for fuel. As proposed, the rule does not apply to new gas-fired stationary combustion turbines used as peaking units, does not apply to existing, modified or reconstructed sources and does not apply to units whose CO_2 emission rate increases as a result of the addition of pollution control equipment to control criteria pollutant emissions or HAPs. The rule is not anticipated to have a significant immediate impact on the AEP System since it does not apply to existing units or units that have already commenced construction. The comment period closed in June 2012. New source performance standards affect units that have not yet received permits, but complete the permitting process while the proposal is pending. The proposed standards were challenged in the United States Court of Appeals for the District of Columbia Circuit. That case was dismissed because the court determined that no final agency action had yet been taken. The Federal EPA is expected to finalize these standards in 2013.

In June 2012, the United States Court of Appeals for the District of Columbia Circuit issued a decision upholding, in all material respects, the Federal EPA's endangerment finding, its regulatory program for CO_2 emissions from new motor vehicles and its plan to phase-in regulation of CO_2 emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. A petition for rehearing was filed which the court denied in December 2012. Petitioners may seek further review in the U.S. Supreme Court.

The Federal EPA also finalized a rule in June 2012 that retains the current thresholds for permitting stationary sources under the PSD and Title V operating permit programs at 100,000 tons per year for new sources and 75,000 tons per year for modified sources. The Federal EPA also confirmed that it will re-evaluate these thresholds during its five-year review in 2016. Our generating units are large sources of CO_2 emissions and we will continue to evaluate the permitting obligations in light of these thresholds.

Coal Combustion Residual Rule

In June 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at coal-fired electric generating units. The rule contains two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials and another would allow states to retain primary authority to regulate the beneficial re-use and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and would require existing unlined surface impoundments to upgrade to the new standards or stop receiving coal ash and initiate closure within five years of the issuance of a final rule. In 2011, the Federal EPA issued a notice of data availability requesting comments on a number of technical reports and other data received during the comment period for the original proposal and requesting comments on potential modeling analyses to update its risk assessment. The Federal EPA has also announced its intention to complete a risk assessment of various beneficial uses of coal ash. Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. The Federal EPA opposed the petition and is seeking additional time to coordinate the issuance of a final rule with the issuance of new effluent limitations under the Clean Water Act for utility facilities.

Currently, approximately 40% of the coal ash and other residual products from our generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. Certain of these uses would no longer be available and others are likely to significantly decline if coal ash and related materials are classified as hazardous wastes. In addition, we currently use surface impoundments and landfills to manage these materials at our generating facilities and will incur significant costs to upgrade or close and replace these existing facilities under the proposed solid waste management alternative. Regulation of these materials as hazardous wastes would significantly increase these costs. As the rule is not final, we are unable to determine a range of potential costs that are reasonably possible of occurring but expect the costs to be significant.

Clean Water Act Regulations

In April 2011, the Federal EPA issued a proposed rule setting forth standards for existing power plants that will reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. Entrainment is when small fish, eggs or larvae are drawn into the cooling water system and affected by heat, chemicals or physical stress. The proposed standards affect all plants withdrawing more than two million gallons of cooling water per day and establish specific intake design and intake velocity standards meant to allow fish to avoid or escape impingement. Compliance with this standard is required within eight years of the effective date of the final rule. The proposed standard for entrainment for existing facilities requires a site-specific evaluation of the available measures for reducing entrainment. The proposed entrainment standard for new units at existing facilities requires either intake flows commensurate with closed cycle cooling or achieving entrainment reductions equivalent to 90% or greater of the reductions that could be achieved with closed cycle cooling. Plants withdrawing more than 125 million gallons of cooling water per day must submit a detailed technology study to be reviewed by the state permitting authority. We are evaluating the proposal and engaged in the collection of additional information regarding the feasibility of implementing this proposal at our facilities. In June 2012, the Federal EPA issued additional Notices of Data Availability and requested public comments. We submitted comments in July 2012. Issuance of a final rule is not expected until June 2013. We are preparing to begin activities to implement the rule following its issuance and an analysis of the final requirements.

In addition, the Federal EPA issued an information collection request and is developing revised effluent limitation guidelines for electricity generating facilities. A proposed rule is expected in 2013 and a final rule in 2014. We are unable to predict the impact of these changes but expect the costs to be significant.

Climate Change

National public policy makers and regulators in the 11 states we serve have diverse views on climate change. We are currently focused on responding to these emerging views with prudent actions, such as improving energy efficiency, investing in developing cost-effective and less carbon-intensive technologies and evaluating our assets across a range of plausible scenarios and outcomes. We are also active participants in a variety of public policy discussions at state and federal levels to assure that proposed new requirements are feasible and the economies of the states we serve are not placed at a competitive disadvantage.

While comprehensive economy-wide regulation of CO_2 emissions might be achieved through future legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO_2 emissions under the existing requirements of the CAA.

Several states have adopted programs that directly regulate CO_2 emissions from power plants. The majority of the states where we have generating facilities have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements. We are taking steps to comply with these requirements. In order to meet these requirements and as a key part of our corporate sustainability effort, we pledged to increase our wind power. By the end of 2012, we secured, through power purchase agreements, 1,994 MW of wind and solar power.

We have taken measurable, voluntary actions to reduce and offset our CO_2 emissions. We participated in a number of voluntary programs to monitor, mitigate and reduce CO_2 emissions, but many of these programs have been discontinued due to anticipated legislative or regulatory actions. We estimate that our 2012 emissions were approximately 122 million metric tons.

Certain groups have filed lawsuits alleging that emissions of CO_2 are a "public nuisance" and seeking injunctive relief and/or damages from small groups of coal-fired electricity generators, petroleum refiners and marketers, coal companies and others. We have been named in pending lawsuits, which we are defending. It is not possible to predict the outcome of these lawsuits or their impact on our operations or financial condition. See "Carbon Dioxide Public Nuisance Claims" and "Alaskan Villages' Claims" sections of Note 5.

Future federal and state legislation or regulations that mandate limits on the emission of CO_2 could result in significant increases in capital expenditures and operating costs, which, in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force our utility subsidiaries to close some coal-fired facilities and could lead to possible impairment of assets. Public perception may ultimately have a significant impact on future legislation and regulation that could adversely affect our ability to recover our investments in coal-fired plants.

Climate change and its resultant impact on weather patterns could modify our customers' power usage. Our customers' energy needs currently vary with weather conditions and the economy. Increased or decreased energy usage could require the acquisition or construction of more generation and transmission assets or cause early retirement of such assets. The timing and duration of extreme weather conditions may require more system backup and contribute to increased system stresses, including service interruptions and increased storm restoration costs. Extreme weather conditions that create high energy demand could raise electricity prices, which could increase the cost of energy we provide to our customers and could provide opportunity for increased wholesale sales and higher margins.

To the extent climate change affects a region's economic health, it could also affect our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods, has an impact on the economic health of our communities. The cost of additional regulatory requirements would normally be borne by consumers through higher prices for energy and purchased goods.

RESULTS OF OPERATIONS

SEGMENTS

Our primary business is the generation, transmission and distribution of electricity. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable segments and their related business activities are outlined below:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Transmission and distribution of electricity through assets owned and operated by our ten utility operating companies.

Transmission Operations

- Development, construction and operation of transmission facilities through investments in our wholly-owned transmission subsidiaries and transmission joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

AEP River Operations

- Commercial barging operations that transport coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers.

Generation and Marketing

- Nonregulated generation in ERCOT.
- Marketing, risk management and retail activities in ERCOT, PJM and MISO.

The table below presents Income Before Extraordinary Item by segment for the years ended December 31, 2012, 2011 and 2010.

	Years Ended December 31,		
	2012	2011	2010
		(in millions)	
Utility Operations	$ 1,299	$ 1,549	$ 1,192
Transmission Operations	43	30	9
AEP River Operations	15	45	37
Generation and Marketing	7	14	25
All Other (a)	(102)	(62)	(45)
Income Before Extraordinary Item	$ 1,262	$ 1,576	$ 1,218

(a) While not considered a reportable segment, All Other includes:
- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations, which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts were financial derivatives which settled and expired in the fourth quarter of 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility, which ended in the fourth quarter of 2011.

AEP CONSOLIDATED

2012 Compared to 2011

Income Before Extraordinary Item decreased from $1,576 million in 2011 to $1,262 million in 2012 primarily due to:

- A decrease in carrying costs income due to the recognition in 2011 of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005 and a related favorable 2011 resolution of contested tax items related to the TCC stranded cost settlement.
- The 2012 impairment for certain Ohio generation plants.
- The loss of retail customers in Ohio to various CRES providers.
- A decrease in weather-related usage.
- The elimination of POLR charges, effective June 2011, partially offset by the 2011 provision for refund of POLR charges. The refund provision was recorded as a result of the October 2011 PUCO remand order.
- Expenses associated with the early retirement of Parent debt in 2012.
- Expenses related to the 2012 sustainable cost reductions.
- The 2012 adjustment of a UK windfall tax provision as a result of a recent related Supreme Court case.

These decreases were partially offset by:

- Successful rate proceedings in our various jurisdictions.
- Lower spending in 2012 as a result of our cost containment efforts.
- A 2011 recording and subsequent 2012 reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of OPCo's modified stipulation.
- The 2011 plant impairments for Sporn Plant Unit 5 and for the FGD project at Muskingum River Plant Unit 5.
- The 2011 write-off related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap as a result of the November 2011 Texas Court of Appeals decision.
- A loss incurred in 2011 related to a settlement of litigation with BOA and Enron.

Average basic shares outstanding increased to 485 million in 2012 from 482 million in 2011. Actual shares outstanding were 486 million as of December 31, 2012.

2011 Compared to 2010

Income Before Extraordinary Item increased from $1,218 million in 2010 to $1,576 million in 2011 primarily due to:

- An increase in carrying costs income due to the recognition in 2011 of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005 and a related favorable 2011 resolution of contested tax items related to the TCC stranded cost settlement.
- A decrease in expenses as a result of the 2010 cost reduction initiatives.
- Successful rate proceedings in our various jurisdictions.

These increases were partially offset by:

- The loss of retail customers in Ohio to various CRES providers.
- Various Ohio adjustments in 2011, including:
  - The plant impairments for Sporn Plant Unit 5 and for the FGD project at Muskingum River Plant Unit 5.
  - A net decrease due to unfavorable Ohio regulatory orders in 2011.
  - The recording of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund.
- The elimination of POLR charges, effective June 2011, partially offset by the 2011 provision for refund of POLR charges. The refund provision was recorded as a result of the October 2011 PUCO remand order.
- A 2011 write-off related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap as a result of the November 2011 Texas Court of Appeals decision.

Average basic shares outstanding increased from 479 million in 2010 to 482 million in 2011. Actual shares outstanding were 483 million as of December 31, 2011.

Our results of operations are discussed below by operating segment.

UTILITY OPERATIONS

We believe that a discussion of the results from our Utility Operations segment on a gross margin basis is most appropriate in order to further understand the key drivers of the segment. Gross Margin represents total revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances and purchased power.

	Years Ended December 31,		
	2012	2011	2010
		(in millions)	
Revenues	$ 13,778	$ 14,200	$ 13,792
Fuel and Purchased Electricity	4,963	5,455	4,996
Gross Margin	8,815	8,745	8,796
Other Operation and Maintenance	3,352	3,539	3,760
Asset Impairments and Other Related Charges	300	139	-
Depreciation and Amortization	1,734	1,613	1,598
Taxes Other Than Income Taxes	828	812	811
Operating Income	2,601	2,642	2,627
Interest and Investment Income	7	29	9
Carrying Costs Income	53	393	70
Allowance for Equity Funds Used During Construction	78	91	77
Interest Expense	(882)	(886)	(942)
Income Before Income Tax Expense and Equity Earnings	1,857	2,269	1,841
Income Tax Expense	560	722	651
Equity Earnings of Unconsolidated Subsidiaries	2	2	2
Income Before Extraordinary Item	$ 1,299	$ 1,549	$ 1,192

Summary of KWh Energy Sales for Utility Operations

	Years Ended December 31,		
	2012	2011	2010
	(in millions of KWhs)		
Retail:			
Residential	58,780	61,655	61,944
Commercial	50,464	50,767	50,748
Industrial	59,154	59,667	57,333
Miscellaneous	3,072	3,100	3,083
Total Retail (a)	171,470	175,189	173,108
Wholesale	41,892	40,519	32,581
Total KWhs	213,362	215,708	205,689

(a) Represents energy delivered to distribution customers.

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income. In general, degree day changes in our eastern region have a larger effect on net income than changes in our western region due to the relative size of the two regions and the number of customers within each region.

Summary of Heating and Cooling Degree Days for Utility Operations

	Years Ended December 31,		
	2012	2011	2010
	(in degree days)		
Eastern Region			
Actual - Heating (a)	2,382	2,794	3,222
Normal - Heating (b)	2,987	2,980	2,983
Actual - Cooling (c)	1,258	1,215	1,307
Normal - Cooling (b)	1,029	1,017	1,002
Western Region			
Actual - Heating (a)	654	1,029	1,112
Normal - Heating (b)	984	984	980
Actual - Cooling (d)	2,852	3,020	2,515
Normal - Cooling (b)	2,372	2,349	2,339

(a) Eastern Region and Western Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.
(d) Western Region cooling degree days are calculated on a 65 degree temperature base for PSO/SWEPCo and a 70 degree temperature base for TCC/TNC.

2012 Compared to 2011

Reconciliation of Year Ended December 31, 2011 to Year Ended December 31, 2012
Income from Utility Operations Before Extraordinary Item
(in millions)

Year Ended December 31, 2011	$	1,549
Changes in Gross Margin:		
Retail Margins		23
Off-system Sales		(19)
Transmission Revenues		83
Other Revenues		(17)
Total Change in Gross Margin		70
Changes in Expenses and Other:		
Other Operation and Maintenance		187
Asset Impairments and Other Related Charges		(161)
Depreciation and Amortization		(121)
Taxes Other Than Income Taxes		(16)
Interest and Investment Income		(22)
Carrying Costs Income		(340)
Allowance for Equity Funds Used During Construction		(13)
Interest Expense		4
Total Change in Expenses and Other		(482)
Income Tax Expense		162
Year Ended December 31, 2012	$	1,299

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** increased $23 million primarily due to the following:
  - Successful rate proceedings in our service territories, which include:
    - A $177 million rate increase for OPCo.
    - An $87 million rate increase for APCo.
    - A $17 million rate increase for I&M.
    - A $13 million rate increase for PSO.
    - An $11 million rate increase for WPCo.

      For the rate increases described above, $156 million relates to riders/trackers which have corresponding increases in other expense items below.
  - A $71 million decrease in other variable electric generation expenses.
  - A $35 million increase due to OPCo's 2012 partial reversal of a 2011 fuel provision based on an April 2012 PUCO order related to the 2009 FAC audit.
  - A $33 million decrease in recoverable PJM expenses in Ohio.
  - A $24 million write-off in 2011 related to APCo's disallowance of certain Virginia environmental costs incurred in 2009 and 2010 as a result of the November 2011 Virginia SCC order.
  - A $9 million deferral of APCo's additional wind purchase costs as a result of the June 2012 Virginia SCC fuel factor order.
  - A $9 million increase due to adjustments for previously disallowed environmental costs by the November 2011 Virginia SCC order subsequently determined in 2012 to be appropriate for recovery by the Supreme Court of Virginia.

These increases were partially offset by:
- A $289 million decrease attributable to Ohio customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.
- A $95 million decrease in weather-related usage in our eastern and western regions primarily due to decreases of 15% and 36%, respectively, in heating degree days and a 6% decrease in cooling degree days in our western region.
- An $85 million net decrease in regulated revenue due to the elimination of POLR charges, effective June 2011, partially offset by the 2011 provision for refund of POLR charges. The refund provision was recorded as a result of the October 2011 PUCO remand order.

- **Margins from Off-system Sales** decreased $19 million primarily due to lower market prices, lower PJM capacity payments and reduced trading and marketing margins, partially offset by higher Ohio CRES capacity revenues.
- **Transmission Revenues** increased $83 million primarily due to net rate increases in ERCOT and increased transmission revenues from Ohio customers who have switched to alternative CRES providers. The increase in transmission revenues related to CRES providers offsets the lost transmission revenues included in Retail Margins above.
- **Other Revenues** decreased $17 million primarily due to a decrease in gains on miscellaneous sales, partially offset by an increase in revenues related to TCC's issuance of securitization bonds in March 2012. This increase in revenues from securitization bonds is partially offset by an increase in Depreciation and Amortization expense.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $187 million primarily due to the following:
  - A $141 million decrease in plant outage and other plant operating and maintenance expenses.
  - A $72 million decrease in nonutility operations and distribution expenses due to prior year cost reduction measures.
  - A $70 million decrease related to the 2011 recording and subsequent 2012 reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of the Ohio modified stipulation.
  - A $41 million decrease due to the 2011 write-off of a portion of the West Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the WVPSC.
  - A $16 million decrease in administrative and general expenses.
  - A $13 million decrease due to APCo's deferral of transmission costs for the Virginia Transmission Rate Adjustment Clause as allowed by the Virginia SCC recovered dollar-for-dollar within Gross Margin.

  These decreases were partially offset by:
  - A $44 million increase due to expenses related to the 2012 sustainable cost reductions.
  - A $42 million increase in energy efficiency programs and other expenses currently recovered dollar-for-dollar in rate recovery riders/trackers within Gross Margin.
  - A $33 million increase due to the 2011 deferral of 2009 storm costs and the 2010 cost reduction initiatives as allowed by the WVPSC.
  - A $27 million increase due to the favorable 2011 asset retirement obligation adjustment for APCo related to the early closure and previous write-off of the Mountaineer Carbon Capture and Storage Product Validation Facility.
  - A $15 million increase in storm-related expenses due to major storms in our eastern region.
  - An $11 million gain from the sale of land in January 2011.
- **Asset Impairments and Other Related Charges** increased $161 million primarily due to the following:
  - A 2012 impairment of $287 million for certain Ohio generation plants, which includes $13 million of related materials and supplies inventory.
  - A 2012 write-off of an additional $13 million related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap.

This increase was partially offset by:
- A 2011 write-off of $49 million related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap as a result of the November 2011 Texas Court of Appeals decision.
- A 2011 plant impairment of $48 million for Sporn Plant Unit 5.
- A 2011 plant impairment of $42 million for FGD project at Muskingum River Plant Unit 5.

- **Depreciation and Amortization** expenses increased $121 million primarily due to the following:
  - A $58 million increase due to shortened depreciable lives for certain OPCo generating plants effective December 2011. The book value of these plants was fully impaired in November 2012.
  - A $51 million increase due to TCC's issuance of securitization bonds in March 2012. The increase in TCC's securitization related amortization is offset within Gross Margin.
  - A $48 million combined increase in depreciation for APCo and I&M primarily due to increases in depreciation rates effective February 2012 (Virginia) and April 2012 (Michigan), respectively. The majority of this increase in depreciation is offset within Gross Margin.
  - An $18 million increase in amortization primarily as a result of the Virginia Environmental Rate Adjustment Clause and the Virginia E&R surcharge, both effective February 2012. This increase in amortization is offset within Gross Margin.
  - An $11 million increase in amortization of OPCo's Deferred Asset Recovery Rider assets as approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012. This increase in amortization is offset within Gross Margin.
  - Overall higher depreciable property balances.

  These increases were partially offset by:
  - A $39 million decrease due to an amortization adjustment approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012.
  - A $28 million decrease due to the deferral of capacity-related depreciation costs as a result of the PUCO's July 2012 approval of OPCo's capacity rate.
  - A $23 million decrease due to OPCo's amortization of carrying costs on deferred fuel as a result of the October 2011 PUCO remand order which allowed the POLR refund to be applied against any deferred fuel balances. The equity amortization was offset by amounts recognized in Carrying Costs Income.
  - A $13 million decrease in OPCo's depreciation due to the 2011 plant impairment of Sporn Plant Unit 5.
- **Taxes Other Than Income Taxes** increased $16 million primarily due to increased property taxes as a result of increased capital investments.
- **Interest and Investment Income** decreased $22 million primarily due to interest income recorded in the third quarter of 2011 for favorable adjustments related to the 2001-2006 federal income tax audit.
- **Carrying Costs Income** decreased $340 million primarily due to the recognition in 2011 of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005 and a related favorable 2011 resolution of contested tax items related to the TCC stranded cost settlement.
- **Allowance for Equity Funds Used During Construction** decreased $13 million primarily due to the completion of APCo's Dresden Plant in January 2012 and I&M's nuclear fuel preparation for usage, partially offset by increases related to SWEPCo's construction of the Turk Plant.
- **Interest Expense** decreased $4 million primarily due to lower long-term interest rates.
- **Income Tax Expense** decreased $162 million primarily due to a decrease in pretax book income, partially offset by the recording of federal and state income tax adjustments.

2011 Compared to 2010

Reconciliation of Year Ended December 31, 2010 to Year Ended December 31, 2011
Income from Utility Operations Before Extraordinary Item
(in millions)

Year Ended December 31, 2010	$ 1,192
Changes in Gross Margin:	
Retail Margins	(139)
Off-system Sales	44
Transmission Revenues	48
Other Revenues	(4)
Total Change in Gross Margin	(51)
Changes in Expenses and Other:	
Other Operation and Maintenance	221
Asset Impairments and Other Related Charges	(139)
Depreciation and Amortization	(15)
Taxes Other Than Income Taxes	(1)
Interest and Investment Income	20
Carrying Costs Income	323
Allowance for Equity Funds Used During Construction	14
Interest Expense	56
Total Change in Expenses and Other	479
Income Tax Expense	(71)
Year Ended December 31, 2011	$ 1,549

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** decreased $139 million primarily due to the following:
  - A $132 million decrease attributable to Ohio customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.
  - An $87 million decrease in weather-related usage in our eastern region primarily due to a 13% decrease in heating degree days and a 7% decrease in cooling degree days.
  - An $84 million decrease in rate related margins for APCo due to the expiration of E&R cost recovery in Virginia.
  - A $60 million decrease due to the elimination of POLR charges, effective June 2011, in Ohio as a result of the October 2011 PUCO remand order.
  - A $51 million net decrease due to unfavorable Ohio and Virginia regulatory orders.
  - A $30 million increase in other variable electric generation expenses.

  These decreases were partially offset by:
  - Successful rate proceedings in our service territories which include:
    - A $120 million rate increase for OPCo.
    - A $63 million rate increase for APCo.
    - A $30 million rate increase for SWEPCo.
    - A $27 million rate increase for KPCo.
    - A $27 million rate increase for I&M.

      For the rate increases described above, $78 million relates to riders/trackers which have corresponding increases in other expense items below.
  - A $38 million increase in weather-related usage in our western region primarily due to a 20% increase in cooling degree days, slightly offset by a 7% decrease in heating degree days.

    - A $30 million increase due to increased SWEPCo gross margin from sales to customers previously served by Valley Electric Membership Corporation (VEMCO). SWEPCo acquired VEMCO assets and began serving VEMCO customers in October 2010.
    - A $14 million increase related to TCC's Transition Funding. This increase is offset by an increase in Depreciation and Amortization expenses.
- **Margins from Off-system Sales** increased $44 million primarily due to an increase in PJM capacity revenues and higher physical sales volumes, partially offset by lower trading and marketing margins.
- **Transmission Revenues** increased $48 million primarily due to net rate increases in PJM and increased transmission revenues for Ohio customers who have switched to alternative CRES providers. The increase in transmission revenues related to CRES providers offsets the lost transmission revenues included in Retail Margins above.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $221 million primarily due to the following:
    - A $280 million decrease due to expenses related to the cost reduction initiatives recorded in 2010.
    - A $54 million decrease due to the 2010 write-off of APCo's Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the Virginia SCC.
    - A $42 million decrease in administrative and general expenses primarily due to a decrease in fringe benefit expenses.
    - A $33 million decrease due to the 2011 deferral of 2010 costs related to storms and our cost reduction initiatives as allowed by the WVPSC.
    - A $27 million decrease due to the favorable 2011 asset retirement obligation adjustment for APCo related to the early closure and previous write-off of the Mountaineer Carbon Capture and Storage Product Validation Facility.
    - An $11 million gain from the sale of land in January 2011.

  These decreases were partially offset by:
    - A $54 million increase in demand side management, energy efficiency programs and other expenses currently recovered dollar-for-dollar in rate recovery riders/trackers within Gross Margin.
    - A $41 million increase due to the 2011 write-off of a portion of the West Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the WVPSC.
    - A $35 million increase related to the 2011 recording of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the approved December 2011 Ohio stipulation agreement.
    - A $33 million increase in storm-related expenses.
    - A $33 million increase in plant outage and other plant operating and maintenance expenses.
    - A $25 million increase due to the 2010 deferral of 2009 storm costs as allowed by the Virginia SCC.
- **Asset Impairments and Other Related Charges** in 2011 included the following:
    - A 2011 plant impairment of $48 million for Sporn Plant Unit 5.
    - A 2011 plant impairment of $42 million for the FGD project at Muskingum River Plant Unit 5.
    - A 2011 write-off of $49 million related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap as a result of the November 2011 Texas Court of Appeals decision.
- **Depreciation and Amortization** expenses increased $15 million primarily due to the following:
    - A $23 million increase due to the amortization of carrying costs on deferred fuel as a result of the October 2011 Ohio POLR remand order.
    - A $20 million increase in depreciation and amortization for TCC primarily due to increased amortization of TCC's Securitized Transition Assets. This increase is partially offset by an increase in revenues within Gross Margin.
    - Overall higher depreciable property balances.

  These increases were partially offset by:
    - A $34 million decrease in depreciation and amortization for APCo primarily due to the expiration of E&R amortization of deferred carrying costs in Virginia.
- **Interest and Investment Income** increased $20 million primarily due to interest income recorded in 2011 for favorable adjustments related to the 2001-2006 federal income tax audit.

- **Carrying Costs Income** increased $323 million due to the 2011 recognition of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005 and a related favorable 2011 resolution of contested tax items related to the TCC stranded cost settlement.
- **Allowance for Equity Funds Used During Construction** increased $14 million primarily due to construction of the Turk and Dresden Plants and various environmental upgrades, partially offset by a decrease due to the completion of the Stall Unit in June 2010.
- **Interest Expense** decreased $56 million primarily due to lower outstanding long-term debt balances and lower long-term interest rates.
- **Income Tax Expense** increased $71 million primarily due to an increase in pretax book income, partially offset by the 2010 tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits and by the recording of federal and state income tax adjustments.

TRANSMISSION OPERATIONS

Wholly-owned Entities

AEP Transmission Company, LLC (AEPTCo), a subsidiary of AEP, has seven wholly-owned transmission companies as follows:

AEP East Transmission Companies (all operating within PJM)

- AEP Appalachian Transmission Company, Inc. (APTCo) (covering Virginia)
- AEP Indiana Michigan Transmission Company, Inc. (IMTCo)
- AEP Kentucky Transmission Company, Inc. (KTCo)
- AEP Ohio Transmission Company, Inc. (OHTCo)
- AEP West Virginia Transmission Company, Inc. (WVTCo)

AEP West Transmission Companies (all operating within SPP)

- AEP Oklahoma Transmission Company, Inc. (OKTCo)
- AEP Southwestern Transmission Company, Inc. (SWTCo) (covering Arkansas and Louisiana)

IMTCo, OHTCo, OKTCo and WVTCo have been approved by the applicable state commissions or are operating where state approval was not necessary. APTCo has been authorized to submit projects for approval from the Virginia SCC. Applications for regulatory approvals have been filed and are currently under consideration in Arkansas, Kentucky and Louisiana.

The AEP East Transmission Companies and the AEP West Transmission Companies have FERC-approved returns on common equity of 11.49% and 11.20%, respectively, based on a capital structure of up to 50% equity. AEPSC and other AEP subsidiaries provide services to the transmission companies through service agreements.

All of the transmission companies' capital needs are provided by Parent, AEPTCo and/or the Utility Money Pool. The Utility Money Pool is used to meet the short-term borrowing needs of AEP regulated utility subsidiaries. The Utility Money Pool operates in accordance with the terms and conditions approved in regulatory orders.

In October 2012, AEPTCo completed a $250 million debt offering and immediately loaned $200 million and $50 million in proceeds to OHTCo and IMTCo, respectively. In December 2012, AEPTCo issued an additional $75 million in debt and immediately loaned the proceeds to OKTCo. AEPTCo will issue an additional $25 million in March 2013 but it is not yet determined which subsidiaries of AEPTCo will receive the proceeds.

Joint Venture Initiatives

We are currently participating in the following joint venture initiatives:

Project Name	Location	Projected Completion Date	Owners (Ownership %)	Total Estimated Project Costs at Completion	AEP's Investment at December 31, 2012	Approved Return on Equity
				(in thousands)		
ETT	Texas (ERCOT)	2022	MidAmerican Energy (50%) AEP (50%)	$ 3,056,000 (a)	$ 353,654	9.96 %
Prairie Wind	Kansas	2014	Westar Energy (50%) MidAmerican Energy (25%) (b) AEP (25%) (b)	180,000	7,091	12.8 %
Pioneer	Indiana	2018 (c)	Duke Energy (50%) AEP (50%)	950,000 (c)	1,876	12.54 %
RITELine IN	Indiana	2019	Exelon (12.5%) (d) AEP (87.5%) (d)	400,000	732 (e)	11.43 %
RITELine IL	Illinois	2019	Commonwealth Edison (75%) Exelon (12.5%) (d) AEP (12.5%) (d)	1,200,000	115 (e)	11.43 %
Transource Missouri	Missouri	2017	Great Plains Energy (13.5%) (f) AEP (86.5%) (f)	445,000	823	(g)%

(a) ETT's investment in current and future projects in ERCOT over the next ten years is expected to be $3.056 billion. Future projects will be evaluated on a case-by-case basis.

(b) AEP owns 25% of Prairie Wind Transmission, LLC (Prairie Wind) through its ownership interest in ETA. ETA is a 50/50 joint venture with MidAmerican Energy and AEP.

(c) The Pioneer project consists of approximately 240 miles of new 765 kV transmission lines, which is estimated to cost $950 million at completion. In August 2012, Pioneer announced it would develop the first 66-mile segment jointly with Northern Indiana Public Service Company at a total estimated cost of $330 million, subject to regulatory approval. The projected completion date for the first 66-mile segment is 2018. The projected completion dates for the remaining segments have not been determined.

(d) AEP owns 87.5% of RITELine Indiana, LLC (RITELine IN) through its ownership interest in RITELine Transmission Development, LLC (RTD) and AEP Transmission Holding Company, LLC (AEPTHC). AEP owns 12.5% of RITELine Illinois, LLC (RITELine IL) through its ownership interest in RTD. RTD is a 50/50 joint venture with Exelon Transmission Company, LLC and AEPTHC.

(e) RITELine IN is a consolidated variable interest entity. RTD received an order from the FERC in October 2011 granting incentives for the RITELine IN and RITELine IL projects. The projects are currently under evaluation by PJM.

(f) AEP owns 86.5% of Transource Missouri through its ownership interest in Transource Energy, LLC (Transource). Transource is a joint venture with AEPTHC and Great Plains Energy formed to pursue competitive transmission projects in PJM, SPP and MISO. AEPTHC and Great Plains Energy own 86.5% and 13.5% of Transource, respectively.

(g) In August 2012, Transource Missouri requested at the FERC a base ROE of 10.6% plus incentives.

In August 2012, the PJM board cancelled the Potomac-Appalachian Transmission Highline Project (PATH Project), our transmission joint venture with FirstEnergy, and removed it from the 2012 Regional Transmission Expansion Plan. In November 2012, the FERC issued an order accepting AEP's and FirstEnergy's abandonment cost recovery filing which requested authority to recover prudently-incurred costs associated with the PATH Project. The FERC also set the issue of prudency of costs for settlement proceedings. AEP's investment in the PATH Project as of December 31, 2012 was $31 million.

For the consolidated entities within our Transmission Operations segment, we forecast approximately $700 million, excluding AFUDC, of construction expenditures for 2013. For the equity investments within our Transmission Operations segment, we forecast approximately $55 million of AEP equity contributions in 2013 to support construction expenditures and the payment of operating expenses.

2012 Compared to 2011

Income Before Extraordinary Item from our Transmission Operations segment increased from $30 million in 2011 to $43 million in 2012 primarily due to an increase in investments by ETT and our wholly-owned transmission subsidiaries.

2011 Compared to 2010

Income Before Extraordinary Item from our Transmission Operations segment increased from $9 million in 2010 to $30 million in 2011 primarily due to an increase in transmission investments by ETT and our wholly-owned transmission subsidiaries.

AEP RIVER OPERATIONS

2012 Compared to 2011

Income Before Extraordinary Item from our AEP River Operations segment decreased from $45 million in 2011 to $15 million in 2012 primarily due to the 2012 drought, which had significant impacts on river conditions and crop yields, resulting in reduced grain exports.

2011 Compared to 2010

Income Before Extraordinary Item from our AEP River Operations segment increased from $37 million in 2010 to $45 million in 2011 primarily due to increased coal exports, increased barge fleet size and the cost reduction initiatives in 2010, partially offset by higher fuel, maintenance and flood-related expenses.

GENERATION AND MARKETING

2012 Compared to 2011

Income Before Extraordinary Item from our Generation and Marketing segment decreased from $14 million in 2011 to $7 million in 2012 primarily due to the expiration of wind-related production tax credits in 2011 and lower gross margins at the Oklaunion Plant, partially offset by higher retail margins in PJM and higher trading margins.

2011 Compared to 2010

Income Before Extraordinary Item from our Generation and Marketing segment decreased from $25 million in 2010 to $14 million in 2011 primarily due to lower gross margins at the Oklaunion Plant.

ALL OTHER

2012 Compared to 2011

Income Before Extraordinary Item from All Other decreased from a loss of $62 million in 2011 to a loss of $102 million in 2012 primarily due to costs associated with the early retirement of debt in 2012 and the 2012 adjustment of a UK windfall tax provision as a result of a recent related Supreme Court case, partially offset by a loss incurred in 2011 related to the settlement of litigation with BOA and Enron.

2011 Compared to 2010

Income Before Extraordinary Item from All Other decreased from a loss of $45 million in 2010 to a loss of $62 million in 2011 primarily due to a loss incurred in 2011 related to the settlement of litigation with BOA and Enron and a gain on the sale of our remaining shares of Intercontinental Exchange, Inc. (ICE) in 2010, partially offset by a contribution to AEP's charitable foundation in 2010.

AEP SYSTEM INCOME TAXES

2012 Compared to 2011

Income Tax Expense decreased $214 million primarily due to a decrease in pretax book income and the unrealized capital loss valuation allowance related to a deferred tax asset associated with the settlement of litigation with BOA and Enron recorded in 2011, partially offset by the recording of federal and state income tax adjustments.

2011 Compared to 2010

Income Tax Expense increased $175 million primarily due to an increase in pretax book income and the unrealized capital loss valuation allowance related to a deferred tax asset associated with the settlement of litigation with BOA and Enron, partially offset by the 2010 tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits and by the recording of federal and state income tax adjustments.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows.

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	December 31,			
	2012		2011	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 17,757	52.3 %	$ 16,516	50.3 %
Short-term Debt	981	2.9	1,650	5.0
Total Debt	18,738	55.2	18,166	55.3
AEP Common Equity	15,237	44.8	14,664	44.7
Noncontrolling Interests	-	-	1	-
Total Debt and Equity Capitalization	$ 33,975	100.0 %	$ 32,831	100.0 %

Our ratio of debt-to-total capital decreased from 55.3% as of December 31, 2011 to 55.2% as of December 31, 2012 primarily due to an increase in common equity, partially offset by a net increase in debt issuances, including the March 2012 issuance of $800 million of securitization bonds.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. We believe we have adequate liquidity under our existing credit facilities. As of December 31, 2012, we had $3.25 billion in aggregate credit facility commitments to support our operations. Additional liquidity is available from cash from operations and a receivables securitization agreement. We are committed to maintaining adequate liquidity. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-leaseback or leasing agreements or common stock.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. As of December 31, 2012, our available liquidity was approximately $3.1 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,500	June 2015
Revolving Credit Facility	1,750	July 2016
Total	3,250	
Cash and Cash Equivalents	279	
Total Liquidity Sources	3,529	
Less: AEP Commercial Paper Outstanding	321	
Letters of Credit Issued	131	
Net Available Liquidity	$ 3,077	

We have credit facilities totaling $3.25 billion to support our commercial paper program. The credit facilities allow us to issue letters of credit in an amount up to $1.35 billion.

In February 2013, we increased and extended the $1.5 billion credit facility due in June 2015 to $1.75 billion due in June 2016, extended the $1.75 billion credit facility due in July 2016 to July 2017 and issued a $1 billion interim credit facility due in May 2015 to fund certain OPCo maturities.

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The maximum amount of commercial paper outstanding during 2012 was $1.2 billion. The weighted-average interest rate for our commercial paper during 2012 was 0.44%.

Financing Plan

As of December 31, 2012, we have $2.2 billion of long-term debt due within one year which includes $528 million of Pollution Control Bonds with mandatory tender dates and credit support for variable interest rates that requires the debt be classified as current. Also included in our long-term debt due within one year is $363 million of securitization bonds and DCC Fuel notes payable which will be repaid. We plan to refinance the majority of our other maturities due within one year.

Securitized Accounts Receivables

In 2012, we renewed our receivables securitization agreement. The agreement provides a commitment of $700 million from bank conduits to purchase receivables. A commitment of $385 million expires in June 2013 and the remaining commitment of $315 million expires in June 2015. We intend to extend or replace the agreement expiring in June 2013 on or before its maturity.

Securitization of Regulatory Assets

In March 2012, West Virginia passed securitization legislation which allows the WVPSC to establish a regulatory framework to securitize certain deferred ENEC balances and other ENEC related assets. In August 2012, APCo and WPCo filed with the WVPSC a request for a financing order to securitize $422 million related to APCo's December 2011 under-recovered ENEC deferral balance, other ENEC-related assets and related financing costs. In January 2013, intervenors filed testimony that recommended securitization of approximately $370 million. The differences between APCo's and WPCo's request and the intervenors' testimony represent previously approved ENEC-related deferred amounts being recovered in the ENEC over extended periods, various amounts deferred subsequent to the 2011 securitization period and related securitization financing costs. APCo and WPCo are currently in settlement discussions with intervenors.

In August 2012, OPCo filed an application with the PUCO requesting securitization of the Deferred Asset Recovery Rider (DARR) balance. As of December 31, 2012, OPCo's DARR balance was $287 million, including $135 million of unrecognized equity carrying costs. Currently, the DARR is being recovered through 2018 by a non-bypassable rider. If the application is approved and the securitization bonds are issued, the DARR will cease and will be replaced by the Deferred Asset Phase-in Rider, which will recover the securitized asset over seven years.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually defined in our revolving credit agreements. Debt as defined in the revolving credit agreements excludes securitization bonds and debt of AEP Credit. As of December 31, 2012, this contractually-defined percentage was 51.3%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of December 31, 2012, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements and in a majority of our non-exchange traded commodity contracts which would permit the lenders and counterparties to declare the outstanding amounts payable. However, a default under our non-exchange traded commodity contracts does not cause an event of default under our revolving credit agreements.

The revolving credit facilities do not permit the lenders to refuse a draw on any facility if a material adverse change occurs.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. As of December 31, 2012, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.47 per share in January 2013. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Our income derives from our common stock equity in the earnings of our utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends.

We do not believe restrictions related to our various financing arrangements and regulatory requirements will have any significant impact on Parent's ability to access cash to meet the payment of dividends on its common stock.

Credit Ratings

We do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit downgrade, but our access to the commercial paper market may depend on our credit ratings. In addition, downgrades in our credit ratings by one of the rating agencies could increase our borrowing costs. Counterparty concerns about the credit quality of AEP or its utility subsidiaries could subject us to additional collateral demands under adequate assurance clauses under our derivative and non-derivative energy contracts.

CASH FLOW

Managing our cash flows is a major factor in maintaining our liquidity strength.

	Years Ended December 31, 2012	2011	2010
		(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 221	$ 294	$ 490
Net Cash Flows from Operating Activities	3,804	3,788	2,662
Net Cash Flows Used for Investing Activities	(3,391)	(2,890)	(2,523)
Net Cash Flows Used for Financing Activities	(355)	(971)	(335)
Net Increase (Decrease) in Cash and Cash Equivalents	58	(73)	(196)
Cash and Cash Equivalents at End of Period	$ 279	$ 221	$ 294

Cash from operations and short-term borrowings provides working capital and allows us to meet other short-term cash needs.

Operating Activities

	Years Ended December 31, 2012	2011	2010
		(in millions)	
Net Income	$ 1,262	$ 1,949	$ 1,218
Depreciation and Amortization	1,782	1,655	1,641
Other	760	184	(197)
Net Cash Flows from Operating Activities	$ 3,804	$ 3,788	$ 2,662

Net Cash Flows from Operating Activities were $3.8 billion in 2012 consisting primarily of Net Income of $1.3 billion, $1.8 billion of noncash Depreciation and Amortization and $287 million in Asset Impairments related to certain Ohio generation assets. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. A significant change in other items includes the unfavorable impact of an increase in fuel inventory due to the mild winter weather. Deferred Income Taxes increased primarily due to provisions in the Small Business Jobs Act and the Tax Relief, Unemployment Insurance Reauthorization and Jobs Creation Act and an increase in tax versus book temporary differences from operations. During 2012, we also contributed $200 million to our qualified pension trust.

Net Cash Flows from Operating Activities were $3.8 billion in 2011 consisting primarily of Net Income of $1.9 billion and $1.7 billion of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Following a Supreme Court of Texas reversal of the PUCT's capacity auction true-up disallowance and the PUCT's approval of a stipulation agreement, we recorded an Extraordinary Item, Net of Tax of $373 million for the 2011 recognition of a regulatory asset related to TCC capacity auction true-up amounts and the reversal of tax related regulatory credits. We also recorded $393 million in Carrying Costs Income primarily related to the Texas restructuring appeals. A significant change in other items includes the favorable impact of a decrease in fuel inventory. Deferred Income Taxes increased primarily due to bonus depreciation provisions in the Small Business Jobs Act and the Tax Relief, Unemployment Insurance Reauthorization and Jobs Creation Act, the settlement with BOA and Enron and an increase in tax versus book temporary differences from operations. In February 2011, we paid $425 million to BOA of which $211 million was used to settle litigation with BOA and Enron. The remaining $214 million was used to acquire cushion gas as discussed in Investing Activities below. During 2011, we also contributed $450 million to our qualified pension trust.

Net Cash Flows from Operating Activities were $2.7 billion in 2010 consisting primarily of Net Income of $1.2 billion and $1.6 billion of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Other includes a $656 million increase in securitized receivables under the application of new accounting guidance for "Transfers and Servicing" related to our sale of receivables agreement. Significant changes in other items include an increase in under-recovered fuel primarily due to the deferral of fuel under the FAC in Ohio and higher fuel costs in Oklahoma, accrued tax benefits and the favorable impact of a decrease in fuel inventory. Deferred Income Taxes increased primarily due to a change in tax versus book temporary differences from operations. Accrued Taxes, Net increased primarily as a result of the receipt of a federal income tax refund of $419 million related to a net operating loss in 2009 that was carried back to 2007 and 2008. We also contributed $500 million to our qualified pension trust in 2010.

Investing Activities

	Years Ended December 31,		
	2012	**2011**	**2010**
		(in millions)	
Construction Expenditures	$ (3,025)	$ (2,669)	$ (2,345)
Acquisitions of Nuclear Fuel	(107)	(106)	(91)
Acquisitions of Assets/Businesses	(94)	(19)	(155)
Acquisitions of Cushion Gas from BOA	-	(214)	-
Proceeds from Sales of Assets	18	123	187
Other	(183)	(5)	(119)
Net Cash Flows Used for Investing Activities	$ (3,391)	$ (2,890)	$ (2,523)

Net Cash Flows Used for Investing Activities were $3.4 billion in 2012 primarily due to Construction Expenditures for new generation, environmental, distribution and transmission investments. Acquisitions of Assets/Businesses include our March 2012 purchase of BlueStar for $70 million.

Net Cash Flows Used for Investing Activities were $2.9 billion in 2011 primarily due to Construction Expenditures for new generation, environmental, distribution and transmission investments. We paid $214 million to BOA for cushion gas as part of a litigation settlement.

Net Cash Flows Used for Investing Activities were $2.5 billion in 2010 primarily due to Construction Expenditures for environmental, new generation, distribution and transmission investments. Proceeds from Sales of Assets in 2010 include $139 million for sales of Texas transmission assets to ETT.

Financing Activities

	Years Ended December 31,		
	2012	**2011**	**2010**
		(in millions)	
Issuance of Common Stock, Net	$ 83	$ 92	$ 93
Issuance/Retirement of Debt, Net	544	(33)	497
Retirement of Cumulative Preferred Stock	-	(64)	-
Dividends Paid on Common Stock	(916)	(898)	(824)
Other	(66)	(68)	(101)
Net Cash Flows Used for Financing Activities	$ (355)	$ (971)	$ (335)

Net Cash Flows Used for Financing Activities in 2012 were $355 million. Our net debt issuances were $544 million. The net issuances included issuances of $1.7 billion of senior unsecured notes, $800 million of securitization bonds, $287 million of notes payable and other debt and $65 million of pollution control bonds offset by retirements of $902 million of senior unsecured and other debt notes, $315 million of junior subordinate debentures, $220 million of pollution control bonds, $206 million of securitization bonds and a decrease in short-term borrowing of $669 million. We paid common stock dividends of $916 million. See Note 13 – Financing Activities.

Net Cash Flows Used for Financing Activities in 2011 were $971 million. Our net debt retirements were $33 million. The net retirements included retirements of $727 million of senior unsecured and other debt notes, $778 million of pollution control bonds and $159 million of securitization bonds offset by issuances of $710 million of notes, $627 million of pollution control bonds and an increase in short-term borrowing of $304 million. We paid common stock dividends of $898 million and $64 million to retire all of our subsidiaries' preferred stocks.

Net Cash Flows Used for Financing Activities in 2010 were $335 million. Our net debt issuances were $497 million. The net issuances included issuances of $952 million of notes and $326 million of pollution control bonds, a $531 million increase in commercial paper outstanding and retirements of $1.6 billion of notes, $148 million of securitization bonds and $222 million of pollution control bonds. Our short-term debt securitized by receivables increased $656 million under the application of new accounting guidance for "Transfers and Servicing" related to our sale of receivables agreement. We paid common stock dividends of $824 million.

The following financing activities occurred during 2012:

AEP Common Stock:

- During 2012, we issued 2.2 million shares of common stock under our incentive compensation, employee savings and dividend reinvestment plans and received net proceeds of $83 million.

Debt:

- During 2012, we issued approximately $2.9 billion of long-term debt, including $1.7 billion of senior notes at interest rates ranging from 1.65% to 4.78% and $800 million of securitization bonds at interest rates ranging from 0.88% to 2.85%. We also issued $65 million of pollution control revenue bonds at 2.25%, $65 million of notes payable at 4.58% and $220 million of other debt at variable interest rates. The proceeds from these issuances were used to fund long-term debt maturities and our construction programs.
- During 2012, we entered into $750 million of interest rate derivatives and settled $458 million of such transactions. The settlements resulted in net cash payments of $23 million. As of December 31, 2012, we had in place $1.2 billion of notional interest rate derivatives designated as cash flow and fair value hedges.

In 2013:

- In January 2013, TCC retired $105 million of its outstanding Securitization Bonds.
- In January and February 2013, I&M retired $23 million of Notes Payable related to DCC Fuel.
- In February 2013, OPCo retired $250 million of 5.5% Senior Unsecured Notes due in 2013.

BUDGETED CONSTRUCTION EXPENDITURES

We forecast approximately $3.6 billion of construction expenditures excluding equity AFUDC and capitalized interest for 2013. For 2014 and 2015, we forecast construction expenditures of $3.8 billion each year. The projected increases are generally the result of required environmental investment to comply with Federal EPA rules and additional transmission spending. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. We expect to fund these construction expenditures through cash flows from operations and financing activities. Generally, the subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. The 2013 estimated construction expenditures include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	2013 Budgeted Construction Expenditures (in millions)
Environmental	$ 544
Generation	647
Transmission	1,286
Distribution	1,009
Other	92
Total	$ 3,578

OFF-BALANCE SHEET ARRANGEMENTS

In prior periods, under a limited set of circumstances, we entered into off-balance sheet arrangements for various reasons including reducing operational expenses and spreading risk of loss to third parties. Our current guidelines restrict the use of off-balance sheet financing entities or structures to traditional operating lease arrangements that we enter in the normal course of business. The following identifies significant off-balance sheet arrangements.

Rockport Plant Unit 2

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 certain institutional investors. The future minimum lease payments for AEGCo and I&M are $739 million and $739 million, respectively, as of December 31, 2012.

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 to AEGCo and I&M. Our subsidiaries account for the lease as an operating lease with the future payment obligations included in Note 12. 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. We, as well as our subsidiaries, have no ownership interest in the Owner Trustee and do not guarantee its debt.

Railcars

In June 2003, we entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. We intend to maintain the lease for the full lease term of twenty years via the renewal options. The lease is accounted for as an operating lease. The future minimum lease obligation is $29 million for the remaining railcars as of December 31, 2012. Under a return-and-sale option, the lessor is guaranteed that the sale proceeds will equal at least a specified lessee obligation amount which declines with each five-year renewal. As of December 31, 2012, the maximum potential loss was approximately $25 million assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair value would produce a sufficient sales price to avoid any loss. We have other railcar lease arrangements that do not utilize this type of financing structure.

CONTRACTUAL OBLIGATION INFORMATION

Our contractual cash obligations include amounts reported on the balance sheets and other obligations disclosed in our footnotes. The following table summarizes our contractual cash obligations as of December 31, 2012:

Payments Due by Period

Contractual Cash Obligations	Less Than 1 Year	2-3 Years	4-5 Years (in millions)	After 5 Years	Total
Short-term Debt (a)	$ 981	$ -	$ -	$ -	$ 981
Interest on Fixed Rate Portion of Long-term Debt (b)	861	1,527	1,308	6,011	9,707
Fixed Rate Portion of Long-term Debt (c)	1,410	2,425	2,493	10,513	16,841
Variable Rate Portion of Long-term Debt (d)	761	182	2	-	945
Capital Lease Obligations (e)	95	144	122	244	605
Noncancelable Operating Leases (e)	302	532	452	1,034	2,320
Fuel Purchase Contracts (f)	2,631	3,971	2,906	3,097	12,605
Energy and Capacity Purchase Contracts (g)	177	359	368	2,494	3,398
Construction Contracts for Capital Assets (h)	859	1,264	1,197	1,326	4,646
Total	$ 8,077	$ 10,404	$ 8,848	$ 24,719	$ 52,048

(a) Represents principal only excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2012 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See "Long-term Debt" section of Note 13. Represents principal only excluding interest.
(d) See "Long-term Debt" section of Note 13. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 0.11% and 2.18% as of December 31, 2012.
(e) See Note 12.
(f) Represents contractual obligations to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual obligations for energy and capacity purchase contracts.
(h) Represents only capital assets for which we have signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

Our $61 million liability related to uncertainty in Income Taxes is not included above because we cannot reasonably estimate the cash flows by period.

Our pension funding requirements are not included in the above table. As of December 31, 2012, we expect to make contributions to our pension plans totaling $108 million in 2013. Estimated contributions of $107 million in 2014 and $107 million in 2015 may vary significantly based on market returns, changes in actuarial assumptions and other factors. Based upon the projected benefit obligation and fair value of assets available to pay pension benefits, our pension plans were 90.2% funded as of December 31, 2012.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds and other commitments. As of December 31, 2012, our commitments outstanding under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period

Other Commercial Commitments	Less Than 1 Year	2-3 Years	4-5 Years (in millions)	After 5 Years	Total
Standby Letters of Credit (a)	$ 131	$ -	$ -	$ -	$ 131
Guarantees of the Performance of Outside Parties (b)	-	-	-	115	115
Guarantees of Our Performance (c)	604	15	10	62	691
Total Commercial Commitments	$ 735	$ 15	$ 10	$ 177	$ 937

(a) We enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves. AEP, on behalf of our subsidiaries, and/or the subsidiaries issued all of these LOCs in the ordinary course of business. There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any LOC is drawn, there is no recourse to third parties. The maximum future payments of these LOCs are $131 million with maturities ranging from January 2013 to April 2014. See "Letters of Credit" section of Note 5.

(b) See "Guarantees of Third-Party Obligations" section of Note 5.

(c) We issued performance guarantees and indemnifications for energy trading and various sale agreements.

SIGNIFICANT TAX LEGISLATION

The Small Business Jobs Act, enacted in September 2010, included 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, this act extended the time for claiming bonus depreciation and increased the deduction to 100% starting in September 2010 through 2011 and decreasing the deduction to 50% for 2012. The American Taxpayer Relief Act of 2012 provided for the extension of several business and energy industry tax deductions and credits, including the one-year extension of the 50% bonus depreciation to 2013.

The enacted provisions had no material impact on net income, financial condition or cash flows in 2012, but are expected to result in material future cash flow benefits.

CYBER SECURITY

Cyber security presents a heightened risk for electric utility systems because a cyber-attack could affect critical energy infrastructure. Breaches to the cyber security of the grid or to our system are potentially disruptive to people, property and commerce and create risk for our business, our investors and our customers. In February 2013, President Obama signed an executive order that addresses how government agencies will operate and support the functions in cyber security as well as redefine how the government interfaces with critical infrastructure, such as the electric grid. We already operate under regulatory cyber security standards to protect critical infrastructure. The cyber security framework that will be developed through this executive order will be reviewed by the FERC. We expect to participate in the process and will share best practices already in place. We protect our critical cyber assets, such as our data centers and transmission operations centers and business network, using multiple layers of cyber security and authentication. We constantly scan the system for risks or threats.

Cyber hackers have been able to breach a number of very secure facilities, from federal agencies, banks and retailers to social media sites. As these events become known and develop, we continually assess our own cyber security tools and processes to determine where we might need to strengthen our defenses.

In recent years, we have taken several steps to enhance our capabilities for identifying risks or threats. AEP became the first utility in the country to build a Cyber Security Operations Center. Funding was included as part of a larger American Recovery and Reinvestment Act Department of Energy Smart Grid Demonstration Project grant. This facility is designed as a pilot cyber threat and information-sharing center specifically for the electric sector.

We have partnered with a nonaffiliated entity to leverage their experience and technical capabilities, which were developed through their work with the U.S. Department of Defense. We work with a consortium of other utilities across the country, learning how best to share information about potential threats and collaborating with each other and with the Department of Homeland Security. We also worked with a nonaffiliated entity to conduct several seminars in 2011 about recognizing and investigating cyber vulnerabilities. Through these types of efforts, we are working to protect AEP while helping our industry advance its cyber security capabilities.

In March 2012, we signed a cooperative research and development agreement with the Department of Homeland Security's Office of Cyber Security and Communications, further enhancing our ability to directly exchange information about cyber threats. In addition, we continue to partner with a number of federal and industry groups to advance the national capabilities of cyber security. Among them is the U.S. Department of Energy, where we are working on several pilot projects covering advanced cyber security and assessment tools.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires us to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. We consider an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on net income or financial condition.

We discuss the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee reviews the disclosures relating to them.

We believe that the current assumptions and other considerations used to estimate amounts reflected in our financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about our critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required

Our 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.

We recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, we match the timing of expense and income recognition with regulated revenues. We also record liabilities for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used

When incurred costs are probable of recovery through regulated rates, we record them as regulatory assets on the balance sheet. We review the probability of recovery at each balance sheet date and whenever new events occur. Similarly, we record regulatory liabilities when a determination is made that a refund is probable or when ordered by a commission. Examples of new events that affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs as well as the return of revenues, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against earnings. A write-off of regulatory assets or establishment of a regulatory liability may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used

A change in the above assumptions may result in a material impact on our net income. Refer to Note 4 for further detail related to regulatory assets and regulatory liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

We record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which we perform on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. In accordance with the applicable state commission regulatory treatment in Arkansas, Louisiana, Oklahoma and Texas, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

The changes in unbilled electric utility revenues for our Utility Operations segment were $5 million, $(81) million and $46 million for the years ended December 31, 2012, 2011 and 2010, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rate increases. Accrued unbilled revenues for the Utility Operations segment were $473 million and $468 million as of December 31, 2012 and 2011, respectively.

In March 2012, our Generation and Marketing segment acquired an independent retail electric supplier. The change in unbilled electric utility revenues for our Generation and Marketing segment was $31 million for the year ended December 31, 2012. Accrued unbilled revenues for the Generation and Marketing segment were $38 million as of December 31, 2012.

Assumptions and Approach Used

For each operating company, we compute the monthly estimate for unbilled revenues as net generation less the current month's billed KWh plus the prior month's unbilled KWh. However, due to meter reading issues, meter drift and other anomalies, a separate monthly calculation limits the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWh to the current month and previous month, on a cycle-by-cycle basis, and by dividing the current month aggregated result by the billed KWh. The limits are statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

Effect if Different Assumptions Used

Significant fluctuations in energy demand for the unbilled period, weather, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1% of the accrued unbilled revenues.

Accounting for Derivative Instruments

Nature of Estimates Required

We consider fair value techniques, valuation adjustments related to credit and liquidity and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used

We measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based primarily on exchange prices and broker quotes. If a quoted market price is not available, we estimate the fair value based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

We reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. We calculate liquidity adjustments by utilizing bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. We calculate credit adjustments on our risk management contracts using estimated default probabilities and recovery rates relative to our counterparties or counterparties with similar credit profiles and contractual netting agreements.

With respect to hedge accounting, we assess hedge effectiveness and evaluate a forecasted transaction's probability of occurrence within the specified time period as provided in the original hedge documentation.

Effect if Different Assumptions Used

There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts settle.

The probability that hedged forecasted transactions will not occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding derivatives, hedging and fair value measurements, see Notes 9 and 10. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of "Property, Plant and Equipment" accounting guidance, we evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable including planned abandonments and a probable disallowance for rate-making on a plant under construction or the assets meet the held-for-sale criteria. We utilize a group composite method of depreciation to estimate the useful lives of long-lived assets. The evaluations of long-lived, held-and-used assets may result from abandonments, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount is not recoverable, we record an impairment to the extent that the fair value of the asset is less than its book value. Performing an impairment evaluation involves a significant degree of estimation and judgment in areas such as identifying circumstances that indicate an impairment may exist, identifying and grouping affected assets and developing the undiscounted and discounted future cash flows (used to estimate fair value in the absence of market-based value, in some instances) associated with the asset. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. For regulated assets, the earnings impact of an impairment charge could be offset by the establishment of a regulatory asset if rate recovery is probable. For nonregulated assets, any impairment charge is recorded against earnings.

Assumptions and Approach Used

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. Cash flow estimates are based on relevant information available at the time the estimates are made. Estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results. Also, when measuring fair value, management evaluates the characteristics of the asset or liability to determine if market participants would take those characteristics into account when pricing the asset or liability at the measurement date. Such characteristics include, for example, the condition and location of the asset or restrictions of the use of the asset. We perform depreciation studies that include a review of any external factors that may affect the useful life to determine composite depreciation rates and related lives which are subject to periodic review by state regulatory commissions for cost-based regulated assets. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used

In connection with the evaluation of long-lived assets in accordance with the requirements of "Property, Plant and Equipment" accounting guidance, the fair value of an asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. The estimate for depreciation rates takes into account the history of interim capital replacements and the amount of salvage expected. In cases of impairment, we made our best estimate of fair value using valuation methods based on the most current information at that time. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and our analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

We maintain a qualified, defined benefit pension plan (Qualified Plan), which covers substantially all nonunion and certain union employees, and unfunded, nonqualified supplemental plans (Nonqualified Plans) to provide benefits in excess of amounts permitted under the provisions of the tax law for participants in the Qualified Plan (collectively the Pension Plans). Additionally, we entered into individual employment contracts with certain current and retired executives that provide additional retirement benefits as a part of the Nonqualified Plans. We also sponsor other postretirement benefit plans to provide health and life insurance benefits for retired employees (Postretirement Plans). The Pension Plans and Postretirement Plans are collectively referred to as the 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. See Note 7 for information regarding costs and assumptions for employee retirement and postretirement benefits.

The following table shows the net periodic cost of the Plans:

	Years Ended December 31,		
Net Periodic Benefit Cost	**2012**	**2011**	**2010**
		(in millions)	
Pension Plans	$ 134	$ 118	$ 141
Postretirement Plans	89	73	111

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2013, we evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. We also considered historical returns of the investment markets and changes in tax rates which affect a portion of the Postretirement Plans' assets. We anticipate that the investment managers we employ for the Plans will invest the assets to generate future returns averaging 6.5% for the Qualified Plan and 7% for the Postretirement Plans.

The expected long-term rate of return on the Plans' assets is based on our targeted asset allocation and our expected investment returns for each investment category. Our assumptions are summarized in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
	2013 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return	2013 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return
Equity	40 %	9.00 %	66 %	8.60 %
Fixed Income	50 %	4.00 %	33 %	3.50 %
Other Investments	10 %	8.80 %	-%	- %
Cash and Cash Equivalents	-%	-%	1 %	1.50 %
Total	100 %		100 %	

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. We believe that 6.5% and 7% are reasonable estimates of the long-term rate of return on the Plans' assets. The Pension Plans' assets had an actual gain of 13.8% and 8.1% for the years ended December 31, 2012 and 2011, respectively. The Postretirement Plans' assets had an actual gain of 15.4% and 0.4% for the years ended December 31, 2012 and 2011, respectively. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

We base our determination of pension expense or income 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. As of December 31, 2012, we had cumulative gains of approximately $302 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial gains may result in decreases in the future pension costs depending on several factors, including whether such gains at each measurement date exceed the corridor in accordance with "Compensation – Retirement Benefits" accounting guidance.

The method used to determine the discount rate that we utilize for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate as of December 31, 2012 under this method was 3.95% for the Qualified Plan, 3.8% for the Nonqualified Plans and 3.95% for the Postretirement Plans. Due to the effect of the unrecognized actuarial gains and based on an expected rate of return on the Pension Plans' assets of 6.5%, discount rates of 3.95% and 3.8% and various other assumptions, we estimate that the pension costs for the Pension Plans will approximate $175 million, $131 million and $102 million in 2013, 2014 and 2015, respectively. Based on an expected rate of return on the Postretirement Plans' assets of 7%, a discount rate of 3.95% and various other assumptions, we estimate credits will approximate $15 million, $19 million and $25 million in 2013, 2014 and 2015, respectively. Future actual costs will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the "Effect if Different Assumptions Used" section below.

In November 2012, we announced changes to our retiree medical coverage. Effective for retirements after December 2012, our contribution to retiree medical costs will be capped reducing our future exposure to medical cost inflation. Effective for employees hired after December 2013, we will not provide retiree medical coverage. This change will reduce costs of the plan beginning in 2013 as shown by the estimated credits for Postretirement Plans in the previous paragraph.

The value of the Pension Plans' assets increased to $4.7 billion as of December 31, 2012 from $4.3 billion as of December 31, 2011 primarily due to investment returns and $200 million of company contributions. During 2012, the Qualified Plan paid $367 million and the Nonqualified Plans paid $16 million in benefits to plan participants. The value of the Postretirement Plans' assets increased to $1.6 billion as of December 31, 2012 from $1.4 billion as of December 31, 2011 primarily due to investment returns and contributions by the company and the participants. The Postretirement Plans paid $151 million in benefits to plan participants during 2012.

Nature of Estimates Required

We sponsor pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. We account for these benefits under "Compensation" and "Plan Accounting" accounting guidance. The measurement of our pension and postretirement benefit obligations, costs and liabilities is dependent on a variety of assumptions.

Assumptions and Approach Used

The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Compensation increase rate
- Cash balance crediting rate
- Health care cost trend rate
- Expected return on plan assets

Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used

The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in millions)			
Effect on December 31, 2012 Benefit Obligations				
Discount Rate	$ (272)	$ 300	$ (105)	$ 116
Compensation Increase Rate	12	(11)	NA	NA
Cash Balance Crediting Rate	39	(35)	NA	NA
Health Care Cost Trend Rate	NA	NA	42	(53)
Effect on 2012 Periodic Cost				
Discount Rate	(17)	18	(11)	12
Compensation Increase Rate	4	(4)	NA	NA
Cash Balance Crediting Rate	11	(10)	NA	NA
Health Care Cost Trend Rate	NA	NA	19	(17)
Expected Return on Plan Assets	(22)	22	(7)	7

NA Not applicable.

ACCOUNTING PRONOUNCEMENTS

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, financial instruments, leases, insurance, hedge accounting and consolidation policy. The ultimate pronouncements resulting from these and future projects could have an impact on our future net income and financial position.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

Our Utility Operations segment is exposed to certain market risks as a major power producer and through its transactions in wholesale electricity, coal and emission allowance trading and marketing contracts. These risks include commodity price risk, interest rate risk and credit risk. In addition, we are exposed to foreign currency exchange risk as we occasionally procure various services and materials used in our energy business from foreign suppliers. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

Our Generation and Marketing segment conducts marketing, risk management and retail activities in ERCOT, PJM and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail electricity. These risks include commodity price risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

We employ risk management contracts including physical forward purchase-and-sale contracts and financial forward purchase-and-sale contracts. We engage in risk management of power, coal and natural gas and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with our established risk management policies as approved by the Finance Committee of our Board of Directors. Our market risk oversight staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The CORC consists of our Chief Operating Officer, Chief Financial Officer, Executive Vice President of Energy Supply, Senior Vice President of Commercial Operations and Chief Risk Officer. When commercial activities exceed predetermined limits, we modify the positions to reduce the risk to be within the limits unless specifically approved by the CORC.

The following table summarizes the reasons for changes in total mark-to-market (MTM) value as compared to December 31, 2011:

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2012

	Utility Operations	Generation and Marketing	Total
		(in millions)	
Total MTM Risk Management Contract Net Assets as of December 31, 2011	$ 59	$ 132	$ 191
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	-	(2)	(2)
Fair Value of New Contracts at Inception When Entered During the Period (a)	5	18	23
Acquisition of Supply Contracts (b)	-	(25)	(25)
Changes in Fair Value Due to Market Fluctuations During the Period (c)	3	5	8
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	1	-	1
Total MTM Risk Management Contract Net Assets as of December 31, 2012	$ 68	$ 128	196
Commodity Cash Flow Hedge Contracts			(12)
Interest Rate and Foreign Currency Cash Flow Hedge Contracts			(37)
Collateral Deposits			43
Total MTM Derivative Contract Net Assets as of December 31, 2012			$ 190

(a) Reflects fair value on primarily long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(b) Reflects liabilities associated with the initial fair value of supply contracts from the BlueStar acquisition in March 2012.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(d) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 9 – Derivatives and Hedging and Note 10 – Fair Value Measurements for additional information related to our risk management contracts. The following tables and discussion provide information on our credit risk and market volatility risk.

Credit Risk

We limit credit risk in our 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. We use Moody's Investors Service, Standard & 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.

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of December 31, 2012, our credit exposure net of collateral to sub investment grade counterparties was approximately 6.5%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of December 31, 2012, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
	(in millions, except number of counterparties)				
Investment Grade	$ 643	$ -	$ 643	2	$ 267
Split Rating	3	2	1	1	1
Noninvestment Grade	1	1	-	-	-
No External Ratings:					
Internal Investment Grade	98	-	98	3	36
Internal Noninvestment Grade	62	10	52	1	34
Total as of December 31, 2012	$ 807	$ 13	$ 794	7	$ 338
Total as of December 31, 2011	$ 960	$ 19	$ 941	5	$ 348

Value at Risk (VaR) Associated with Risk Management Contracts

We use a risk measurement model, which calculates VaR, to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of December 31, 2012, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

The following table shows the end, high, average and low market risk as measured by VaR for the trading portfolio for the periods indicated:

VaR Model

Twelve Months Ended December 31, 2012				Twelve Months Ended December 31, 2011			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ -	$ 1	$ -	$ -	$ -	$ 2	$ -	$ -

We back-test our VaR results against performance due to actual price movements. Based on the assumed 95% confidence interval, the performance due to actual price movements would be expected to exceed the VaR at least once every 20 trading days.

As our VaR calculation captures recent price movements, we also perform regular stress testing of the portfolio to understand our exposure to extreme price movements. We employ a historical-based method whereby the current portfolio is subjected to actual, observed price movements from the last four years in order to ascertain which historical price movements translated into the largest potential MTM loss. We then research the underlying positions, price movements and market events that created the most significant exposure and report the findings to the Risk Executive Committee or the CORC as appropriate.

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which our interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of December 31, 2012 and 2011, the estimated EaR on our debt portfolio for the following twelve months was $42 million and $29 million, respectively.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.:

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2012, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2013 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 26, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.:

We have audited the internal control over financial reporting of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2012, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2012 of the Company and our report dated February 26, 2013 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 26, 2013

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of American Electric Power Company, Inc. and subsidiary companies (AEP) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of AEP's internal control over financial reporting as of December 31, 2012. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management's assessment, AEP's internal control over financial reporting was effective as of December 31, 2012.

AEP's independent registered public accounting firm has issued an attestation report on AEP's internal control over financial reporting. The Report of Independent Registered Public Accounting Firm appears on the previous page.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011 and 2010
(in millions, except per-share and share amounts)

	Years Ended December 31, 2012	2011	2010
REVENUES			
Utility Operations	$ 13,677	$ 14,091	$ 13,687
Other Revenues	1,268	1,025	740
TOTAL REVENUES	14,945	15,116	14,427
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	4,111	4,421	4,029
Purchased Electricity for Resale	1,169	1,191	1,000
Other Operation	2,962	2,868	3,132
Maintenance	1,115	1,236	1,142
Asset Impairments and Other Related Charges	300	139	-
Depreciation and Amortization	1,782	1,655	1,641
Taxes Other Than Income Taxes	850	824	820
TOTAL EXPENSES	12,289	12,334	11,764
OPERATING INCOME	2,656	2,782	2,663
Other Income (Expense):			
Interest and Investment Income	8	27	38
Carrying Costs Income	53	393	70
Allowance for Equity Funds Used During Construction	93	98	77
Interest Expense	(988)	(933)	(999)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	1,822	2,367	1,849
Income Tax Expense	604	818	643
Equity Earnings of Unconsolidated Subsidiaries	44	27	12
INCOME BEFORE EXTRAORDINARY ITEM	1,262	1,576	1,218
EXTRAORDINARY ITEM, NET OF TAX	-	373	-
NET INCOME	1,262	1,949	1,218
Net Income Attributable to Noncontrolling Interests	3	3	4
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,259	1,946	1,214
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	5	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,259	$ 1,941	$ 1,211
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	484,682,469	482,169,282	479,373,306
BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Extraordinary Item	$ 2.60	$ 3.25	$ 2.53
Extraordinary Item, Net of Tax	-	0.77	-
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.60	$ 4.02	$ 2.53
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	485,084,694	482,460,328	479,601,442
DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Extraordinary Item	$ 2.60	$ 3.25	$ 2.53
Extraordinary Item, Net of Tax	-	0.77	-
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.60	$ 4.02	$ 2.53
CASH DIVIDENDS DECLARED PER SHARE	$ 1.88	$ 1.85	$ 1.71

See Notes to Consolidated Financial Statements beginning on page 54.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2012, 2011 and 2010
(in millions)

	Years Ended December 31,		
	2012	2011	2010
Net Income	$ 1,262	$ 1,949	$ 1,218
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $8, $18 and $14 in 2012, 2011 and 2010, Respectively	(15)	(34)	26
Securities Available for Sale, Net of Tax of $1, $1 and $4 in 2012, 2011 and 2010, Respectively	2	(2)	(8)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $16, $13 and $12 in 2012, 2011 and 2010, Respectively	31	24	22
Pension and OPEB Funded Status, Net of Tax of $62, $41 and $25 in 2012, 2011 and 2010, Respectively	115	(77)	(47)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	133	(89)	(7)
TOTAL COMPREHENSIVE INCOME	1,395	1,860	1,211
Total Comprehensive Income Attributable to Noncontrolling Interests	3	3	4
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,392	1,857	1,207
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	5	3
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,392	$ 1,852	$ 1,204

See Notes to Consolidated Financial Statements beginning on page 54.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2012, 2011 and 2010
(in millions)

	AEP Common Shareholders						
	Common Stock				Accumulated Other		
	Shares	Amount	Paid-in Capital	Retained Earnings	Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2009	498	$ 3,239	$ 5,824	$ 4,451	$ (374)	$ -	$ 13,140
Issuance of Common Stock	3	18	75				93
Common Stock Dividends				(820)		(4)	(824)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Other Changes in Equity			5				5
Subtotal – Equity							12,411
Net Income				1,214		4	1,218
Other Comprehensive Loss					(7)		(7)
TOTAL EQUITY – DECEMBER 31, 2010	501	3,257	5,904	4,842	(381)	-	13,622
Issuance of Common Stock	3	17	75				92
Common Stock Dividends				(894)		(4)	(898)
Preferred Stock Dividend Requirements of Subsidiaries				(2)			(2)
Loss on Reacquired Preferred Stock			(4)				(4)
Capital Stock Expense			(16)				(16)
Other Changes in Equity			11	(2)		2	11
Subtotal – Equity							12,805
Net Income				1,946		3	1,949
Other Comprehensive Loss					(89)		(89)
TOTAL EQUITY – DECEMBER 31, 2011	504	3,274	5,970	5,890	(470)	1	14,665
Issuance of Common Stock	2	15	68				83
Common Stock Dividends				(913)		(3)	(916)
Other Changes in Equity			11			(1)	10
Subtotal – Equity							13,842
Net Income				1,259		3	1,262
Other Comprehensive Income					133		133
TOTAL EQUITY – DECEMBER 31, 2012	506	$ 3,289	$ 6,049	$ 6,236	$ (337)	$ -	$ 15,237

See Notes to Consolidated Financial Statements beginning on page 54.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2012 and 2011
(in millions)

	December 31, 2012	December 31, 2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 279	$ 221
Other Temporary Investments		
(December 31, 2012 and 2011 Amounts Include $311 and $281, Respectively, Related to Transition Funding and EIS)	324	294
Accounts Receivable:		
Customers	685	690
Accrued Unbilled Revenues	195	106
Pledged Accounts Receivable - AEP Credit	856	920
Miscellaneous	171	150
Allowance for Uncollectible Accounts	(36)	(32)
Total Accounts Receivable	1,871	1,834
Fuel	844	657
Materials and Supplies	675	635
Risk Management Assets	191	193
Regulatory Asset for Under-Recovered Fuel Costs	88	65
Margin Deposits	76	67
Prepayments and Other Current Assets	241	216
TOTAL CURRENT ASSETS	4,589	4,182
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	26,279	24,938
Transmission	9,846	9,048
Distribution	15,565	14,783
Other Property, Plant and Equipment (Including Nuclear Fuel and Coal Mining)	3,945	3,780
Construction Work in Progress	1,819	3,121
Total Property, Plant and Equipment	57,454	55,670
Accumulated Depreciation and Amortization	18,691	18,699
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET	38,763	36,971
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,106	6,026
Securitized Transition Assets	2,117	1,627
Spent Nuclear Fuel and Decommissioning Trusts	1,706	1,592
Goodwill	91	76
Long-term Risk Management Assets	368	403
Deferred Charges and Other Noncurrent Assets	1,627	1,346
TOTAL OTHER NONCURRENT ASSETS	11,015	11,070
TOTAL ASSETS	$ 54,367	$ 52,223

See Notes to Consolidated Financial Statements beginning on page 54.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2012 and 2011
(dollars in millions)

	December 31, 2012	December 31, 2011
CURRENT LIABILITIES		
Accounts Payable	$ 1,169	$ 1,095
Short-term Debt:		
Securitized Debt for Receivables - AEP Credit	657	666
Other Short-term Debt	324	984
Total Short-term Debt	981	1,650
Long-term Debt Due Within One Year (December 31, 2012 and 2011 Amounts Include $367 and $293, Respectively, Related to Transition Funding, DCC Fuel and Sabine)	2,171	1,433
Risk Management Liabilities	155	150
Customer Deposits	316	289
Accrued Taxes	747	717
Accrued Interest	269	279
Regulatory Liability for Over-Recovered Fuel Costs	47	8
Other Current Liabilities	968	990
TOTAL CURRENT LIABILITIES	6,823	6,611
NONCURRENT LIABILITIES		
Long-term Debt (December 31, 2012 and 2011 Amounts Include $2,227 and $1,674, Respectively, Related to Transition Funding, DCC Fuel and Sabine)	15,586	15,083
Long-term Risk Management Liabilities	214	195
Deferred Income Taxes	9,252	8,227
Regulatory Liabilities and Deferred Investment Tax Credits	3,544	3,195
Asset Retirement Obligations	1,696	1,472
Employee Benefits and Pension Obligations	1,075	1,801
Deferred Credits and Other Noncurrent Liabilities	940	974
TOTAL NONCURRENT LIABILITIES	32,307	30,947
TOTAL LIABILITIES	39,130	37,558
Rate Matters (Note 3)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2012	2011
Shares Authorized	600,000,000	600,000,000
Shares Issued	506,004,962	503,759,460

	2012	2011
(20,336,592 Shares were Held in Treasury as of December 31, 2012 and 2011)	3,289	3,274
Paid-in Capital	6,049	5,970
Retained Earnings	6,236	5,890
Accumulated Other Comprehensive Income (Loss)	(337)	(470)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	15,237	14,664
Noncontrolling Interests	-	1
TOTAL EQUITY	15,237	14,665
TOTAL LIABILITIES AND EQUITY	$ 54,367	$ 52,223

See Notes to Consolidated Financial Statements beginning on page 54.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011 and 2010
(in millions)

	Years Ended December 31, 2012	2011	2010
OPERATING ACTIVITIES			
Net Income	$ 1,262	$ 1,949	$ 1,218
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,782	1,655	1,641
Deferred Income Taxes	636	794	809
Gain on Settlement with BOA and Enron	-	(51)	-
Settlement of Litigation with BOA and Enron	-	(211)	-
Extraordinary Item, Net of Tax	-	(373)	-
Asset Impairments and Other Related Charges	300	139	-
Carrying Costs Income	(53)	(393)	(70)
Allowance for Equity Funds Used During Construction	(93)	(98)	(77)
Mark-to-Market of Risk Management Contracts	57	37	30
Amortization of Nuclear Fuel	136	137	139
Pension Contributions to Qualified Plan Trust	(200)	(450)	(500)
Property Taxes	(19)	(15)	(21)
Fuel Over/Under-Recovery, Net	157	(25)	(253)
Change in Other Noncurrent Assets	(236)	(112)	(89)
Change in Other Noncurrent Liabilities	127	307	202
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(16)	107	(866)
Fuel, Materials and Supplies	(224)	176	221
Accounts Payable	(60)	(44)	(36)
Accrued Taxes, Net	174	193	179
Other Current Assets	(3)	37	73
Other Current Liabilities	77	29	62
Net Cash Flows from Operating Activities	3,804	3,788	2,662
INVESTING ACTIVITIES			
Construction Expenditures	(3,025)	(2,669)	(2,345)
Change in Other Temporary Investments, Net	(27)	8	(4)
Purchases of Investment Securities	(1,047)	(1,321)	(1,918)
Sales of Investment Securities	988	1,379	1,817
Acquisitions of Nuclear Fuel	(107)	(106)	(91)
Acquisitions of Assets/Businesses	(94)	(19)	(155)
Acquisition of Cushion Gas from BOA	-	(214)	-
Proceeds from Sales of Assets	18	123	187
Other Investing Activities	(97)	(71)	(14)
Net Cash Flows Used for Investing Activities	(3,391)	(2,890)	(2,523)
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	83	92	93
Issuance of Long-term Debt	2,856	1,328	1,270
Commercial Paper and Credit Facility Borrowings	25	488	565
Change in Short-term Debt, Net	(654)	744	770
Retirement of Long-term Debt	(1,643)	(1,665)	(1,993)
Retirement of Cumulative Preferred Stock	-	(64)	-
Commercial Paper and Credit Facility Repayments	(40)	(928)	(115)
Principal Payments for Capital Lease Obligations	(71)	(71)	(95)
Dividends Paid on Common Stock	(916)	(898)	(824)
Dividends Paid on Cumulative Preferred Stock	-	(2)	(3)
Other Financing Activities	5	5	(3)
Net Cash Flows Used for Financing Activities	(355)	(971)	(335)
Net Increase (Decrease) in Cash and Cash Equivalents	58	(73)	(196)
Cash and Cash Equivalents at Beginning of Period	221	294	490
Cash and Cash Equivalents at End of Period	$ 279	$ 221	$ 294

See Notes to Consolidated Financial Statements beginning on page 54.

**AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

Our principal business is the generation, transmission and distribution of electric power. The subsidiaries that conduct most of these activities are regulated by the FERC under the Federal Power Act and the Energy Policy Act of 2005 and maintain accounts in accordance with the FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

We provide electric supply for residential, commercial and industrial customers in Ohio, Illinois and other deregulated electricity markets and also provide energy management solutions throughout the United States, including energy efficiency services through our independent retail electric supplier.

We also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States and provide various energy-related services. In addition, our operations include nonregulated wind farms and barging operations.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

Our public utility subsidiaries' rates are regulated by the FERC and state regulatory commissions in our eleven state operating territories. The FERC also regulates our affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of our public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires 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. Our wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when we negotiate and file a cost-based contract with the FERC or the FERC determines that we have "market power" in the region where the transaction occurs. We have 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. Our wholesale power transactions in the SPP region are cost-based due to the FERC's finding that PSO and SWEPCo have market power in the SPP region.

The state regulatory commissions regulate all of the distribution operations and rates of our retail public utilities on a cost basis. The state regulatory commissions also regulate the retail generation/power supply operations and rates except in Ohio and the ERCOT region of Texas. The ESP rates in Ohio continue the process of aligning generation/power supply rates over time with market rates. In the ERCOT region of Texas, the generation/supply business is under customer choice and market pricing and is conducted by Texas Retail Electric Providers (REPs). Through our nonregulated subsidiaries, we enter into short and long-term wholesale transactions to buy or sell capacity, energy and ancillary services in the ERCOT market. In addition, these nonregulated subsidiaries control certain wind and coal-fired generation assets, the power from which is marketed and sold in ERCOT. We have no active REPs in ERCOT.

The FERC also regulates our wholesale transmission operations and rates. The FERC claims jurisdiction over retail transmission rates when retail rates are unbundled in connection with restructuring. OPCo's retail transmission rates in Ohio, APCo's retail transmission rates in Virginia, I&M's retail transmission rates in Michigan and TCC's and TNC's retail transmission rates in Texas are unbundled. OPCo's retail transmission rates in Ohio, APCo's retail transmission rates in Virginia and I&M's retail transmission rates in Michigan are based on formula rates included in the PJM OATT that are cost-based. Although TCC's and TNC's retail transmission rates in Texas are unbundled, retail transmission rates are regulated, on a cost basis, by the PUCT. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions. Transmission rates for our seven wholly-owned transmission subsidiaries within our Transmission Operations segment are based on formula rates included in the applicable RTO's OATT that are cost-based.

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 utility subsidiaries that are parties to each agreement. In October 2012, the AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and the AEP System Interim Allowance Agreement and approve a new Power Coordination Agreement among APCo, I&M and KPCo. A decision is expected from the FERC in mid-2013.

Principles of Consolidation

Our consolidated financial statements include our wholly-owned and majority-owned subsidiaries and VIEs of which we are the primary beneficiary. Intercompany items are eliminated in consolidation. We use the equity method of accounting for equity investments where we exercise significant influence but do not hold a controlling financial interest. Such investments are recorded as Deferred Charges and Other Noncurrent Assets on the balance sheets; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on the statements of income. We have ownership interests in generating units that are jointly-owned with nonaffiliated companies. Our proportionate share of the operating costs associated with such facilities is included on the statements of income and our proportionate share of the assets and liabilities are reflected on the balance sheets.

Accounting for the Effects of Cost-Based Regulation

As the owner of rate-regulated electric public utility companies, our 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," we record regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates. Due to the passage of legislation requiring restructuring and a transition to customer choice and market-based rates, we discontinued the application of "Regulated Operations" accounting treatment for the generation portion of our business in Texas for TNC. OPCo applies "Regulated Operations" accounting treatment only to specifically approved portions of its generation business consisting of fuel and capacity costs.

Use of Estimates

The preparation of these financial statements in conformity with GAAP 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, goodwill, intangible and long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Other Temporary Investments

Other Temporary Investments include funds held by trustees primarily for the payment of securitization bonds, marketable securities that we intend to hold for less than one year and investments by our protected cell of EIS.

We classify our investments in marketable securities as available-for-sale or held-to-maturity in accordance with the provisions of "Investments – Debt and Equity Securities" accounting guidance. We do not have any investments classified as trading.

Available-for-sale securities reflected in Other Temporary Investments are carried at fair value with the unrealized gain or loss, net of tax, reported in AOCI. Held-to-maturity securities reflected in Other Temporary Investments are carried at amortized cost. The cost of securities sold is based on the specific identification or weighted average cost method.

In evaluating potential impairment of securities with unrealized losses, we considered, among other criteria, the current fair value compared to cost, the length of time the security's fair value has been below cost, our intent and ability to retain the investment for a period of time sufficient to allow for any anticipated recovery in value and current economic conditions. See "Fair Value Measurements of Other Temporary Investments" in Note 10.

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 our risk management activities and customer receivables primarily related to other revenue-generating activities.

We recognize revenue from electric power sales when we deliver power to our customers. To the extent that deliveries have occurred but a bill has not been issued, we accrue and recognize, as Accrued Unbilled Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, for I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the billed and unbilled receivables AEP Credit acquires from affiliated utility subsidiaries.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from participating AEP subsidiaries. For receivables related to APCo's West Virginia operations, the bad debt reserve is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable. For customer accounts receivables related to our risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For the wires business of TCC and TNC, bad debt reserves are calculated using the specific identification of receivable balances greater than 120 days delinquent, and for those balances less than 120 days where the collection is doubtful. 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.

Emission Allowances

In regulated jurisdictions including Ohio through December 31, 2014, we record emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. In Ohio, we record allowances expected to be consumed subsequent to December 31, 2014 at the lower of cost or market when our allowances are no longer included in the FAC due to energy auctions of SSO load. We follow the inventory model for these allowances. We record allowances expected to be consumed within one year in Materials and Supplies and allowances with expected consumption beyond one year in Deferred Charges and Other Noncurrent Assets on the balance sheets. We record the consumption of allowances in the production of energy in Fuel and Other Consumables Used for Electric Generation on the statements of income at an average cost. We record allowances held for speculation in Prepayments and Other Current Assets on the balance sheets. We report the purchases and sales of allowances in the Operating Activities section of the statements of cash flows. We record the net margin on sales of emission allowances in Utility Operations Revenue on the statements of income because of its integral nature to the production process of energy and our revenue optimization strategy for our utility operations. The net margin on sales of emission allowances affects the determination of deferred fuel or deferred emission allowance costs and the amortization of regulatory assets for certain jurisdictions.

Property, Plant and Equipment and Equity Investments

Regulated

Electric utility property, plant and equipment for our rate-regulated operations are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities. The costs of labor, materials and overhead incurred to operate and maintain our 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 held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense. Equity investments are required to be tested for impairment when it is determined there may be an other-than-temporary loss in value.

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.

Nonregulated

Our nonregulated operations generally follow the policies of our rate-regulated operations listed above but with the following exceptions. Property, plant and equipment of nonregulated operations and equity investments (included in Deferred Charges and Other Noncurrent Assets) are stated at fair value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for most nonregulated operations under the group composite method of depreciation. For nonregulated plant assets, a gain or loss would be recorded if the retirement is not considered an interim routine replacement. Removal costs are charged to expense.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

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. For nonregulated operations, including generating assets owned by OPCo and certain generating assets in Arkansas and Texas, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest". We record the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense.

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable, Accounts Payable and Short-term Debt 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. Our market risk oversight staff independently monitors our valuation policies and procedures and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and monthly reports, regarding compliance with policies and procedures. The CORC consists of our Chief Operating Officer, Chief Financial Officer, Executive Vice President of Energy Supply, Senior Vice President of Commercial Operations and Chief Risk Officer.

For our 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. We verify our price curves using these broker quotes and classify these fair values within Level 2 when substantially all of the fair value can be corroborated. We typically obtain multiple broker quotes, which are nonbinding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, we average the quoted bid and ask prices. In certain circumstances, we may discard a broker quote if it is a clear outlier. We use a historical correlation analysis between the broker quoted location and the illiquid locations and if the points are highly correlated we include these locations within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of our contracts being classified as Level 3 is the inability to substantiate our energy price curves in the market. A significant portion of our Level 3 instruments have been economically hedged which greatly limits potential earnings volatility.

We utilize our trustee's external pricing service in our estimate of the fair value of the underlying investments held in the benefit plan and nuclear trusts. Our investment managers review and validate the prices utilized by the trustee to determine fair value. We perform our own valuation testing to verify the fair values of the securities. We receive audit reports of our 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, Cash and Cash Equivalents and Other Temporary Investments 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 Fuel and Other Consumables Used for Electric Generation 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 current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally deferred as current regulatory assets. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a phase-in plan or the FAC has been suspended. These deferrals are amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit our fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a fuel cost disallowance becomes probable, we adjust our FAC deferrals and record provisions for estimated refunds to recognize these probable outcomes.

Changes in fuel costs, including purchased power in Kentucky for KPCo, in Indiana and Michigan for I&M, in Ohio (beginning in 2012 through the ESP related to non-auction standard service offer load served) for OPCo, in Arkansas, Louisiana and Texas for SWEPCo, in Oklahoma for PSO and in Virginia for APCo are reflected in rates in a timely manner generally through the FAC. Changes in fuel costs, including purchased power in Ohio (beginning in 2009 through 2011) for OPCo and in West Virginia for APCo are reflected in rates through FAC phase-in plans. The FAC generally includes some sharing of off-system sales. In West Virginia for APCo, all of the profits from off-system sales are given to customers through the FAC. None of the profits from off-system sales are given to customers through the FAC in Ohio for OPCo. A portion of profits from off-system sales are given to customers through the FAC and other rate mechanisms in Oklahoma for PSO, Arkansas, Louisiana and Texas for SWEPCo, Kentucky for KPCo, Virginia for APCo and in Indiana and Michigan (all areas of Michigan beginning in December 2010) for I&M. Where the FAC or off-system sales sharing mechanism is capped, frozen or non-existent, changes in fuel costs or sharing of off-system sales impacted earnings.

Revenue Recognition

Regulatory Accounting

Our 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, we record them as assets on the balance sheets. We test 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, we write off that regulatory asset as a charge against income.

Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. For regulated and nonregulated operations, we recognize the revenues on the statements of income upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

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. We purchase power from PJM to supply our customers. Generally, these power sales and purchases are reported on a net basis as revenues on the statements of income. However, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are recorded gross as Purchased Electricity for Resale on the statements of income. Other RTOs in which we participate 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 Purchased Electricity for Resale 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 Purchased Electricity for Resale on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, we record 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 where generation/supply rates are not cost-based regulated. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

We engage in wholesale electricity, coal, natural gas and emission allowances marketing and risk management activities focused on wholesale markets where we own assets and adjacent markets. Our activities include the purchase and sale of energy under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. We engage in certain energy marketing and risk management transactions with RTOs.

We recognize revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. We use 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. We include unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM in Revenues on the statements of income on a net basis. In jurisdictions subject to cost-based regulation, we defer unrealized MTM amounts and some realized gains and losses as regulatory assets (for losses) and regulatory liabilities (for gains). We include unrealized MTM gains and losses resulting from derivative contracts on the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying wholesale marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). We initially record 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, we subsequently reclassify 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 the statements of income. Excluding those jurisdictions subject to cost-based regulation, we recognize the ineffective portion of the gain or loss in revenues or expense immediately on the statements of income, depending on the specific nature of the associated hedged risk. In regulated jurisdictions, we defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Accounting for Cash Flow Hedging Strategies" section of Note 9.

Barging Activities

AEP River Operations' revenue is recognized based on percentage of voyage completion. The proportion of freight transportation revenue to be recognized is determined by applying a percentage to the contractual charges for such services. The percentage is determined by dividing the number of miles from the loading point to the position of the barge as of the end of the accounting period by the total miles to the destination specified in the customer's freight contract. The position of the barge at accounting period end is determined by our computerized barge tracking system.

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

We expense maintenance costs as incurred. If it becomes probable that we will recover specifically-incurred costs through future rates, we establish a regulatory asset to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. In certain regulatory jurisdictions, we defer costs above the level included in base rates and amortize those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment Tax Credits

We use the liability method of accounting for income taxes. Under the liability method, we provide deferred income taxes 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), we record deferred income taxes and establish related regulatory assets and liabilities to match the regulated revenues and tax expense.

We account for investment tax credits under the flow-through method except where regulatory commissions reflect investment tax credits in the rate-making process on a deferral basis. We amortize deferred investment tax credits over the life of the plant investment.

We account for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." We classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation expense.

Excise Taxes

We act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on our customers. We do not recognize these taxes as revenue or expense.

Government Grants

For APCo's commercial scale carbon capture and sequestration facility at the Mountaineer Plant and OPCo's gridSMART® demonstration program, APCo and OPCo are reimbursed by the Department of Energy for allowable costs incurred during the billing period. In addition, AEP built a cyber security operations center that will be used to enhance the capabilities for identifying cyber risks or threats, which was also partially funded by the gridSMART® demonstration grant for OPCo's incurred costs. These reimbursements result in the reduction of Other Operation and Maintenance expenses on the statements of income or a reduction in Construction Work in Progress on the balance sheets.

Debt

We defer gains and losses from the reacquisition of debt used to finance regulated electric utility plants and amortize the deferral over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If we refinance the reacquired debt associated with the regulated business, the reacquisition costs attributable to the portions of the business subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. We report gains and losses on the reacquisition of debt for operations not subject to cost-based rate regulation in Interest Expense on the statements of income.

We defer debt discount or premium and debt issuance expenses and amortize 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. We include the net amortization expense in Interest Expense on the statements of income.

Goodwill and Intangible Assets

When we acquire businesses, we record the fair value of all assets and liabilities, including intangible assets. To the extent that consideration exceeds the fair value of identified assets, we record goodwill. We do not amortize goodwill and intangible assets with indefinite lives. We test acquired goodwill and other intangible assets with indefinite lives for impairment at least annually at their estimated fair value. We test goodwill at the reporting unit level and other intangibles at the asset level. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods. We amortize intangible assets with finite lives over their respective estimated lives to their estimated residual values. We also review the lives of the amortizable intangibles with finite lives on an annual basis.

Investments Held in Trust for Future Liabilities

We have 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 our trust funds' investments are diversified and managed in compliance with all laws and regulations. Our 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. We regularly review the actual asset allocations and periodically rebalance 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 our 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	40.0 %
Fixed Income	50.0 %
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, our investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law. Each investment manager's portfolio is compared to a diversified benchmark index.

For equity investments, the limits are as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No individual stock may be more than 10% of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, the concentration limits must not exceed:

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

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

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

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and development risk classifications and some investments in Real Estate Investment Trusts (REITs), which are publicly traded real estate securities 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. Our private equity holdings are with multiple general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investment instruments. Commingled private equity funds are used to enhance the holdings' diversity.

We participate 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. We lend 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.

We hold trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company 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 us 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 or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

We maintain trust records 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.

We record securities held in these trust funds as Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets. We record these securities at fair value. We classify 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 gain or loss due to the adjusted cost of investment. We record unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. See the "Nuclear Contingencies" section of Note 5 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 10 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss)

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

Accumulated Other Comprehensive Income (Loss) (AOCI)

AOCI is included on the balance sheets in our equity section. Our components of AOCI as of December 31, 2012 and 2011 are shown in the following table:

Components	December 31, 2012	December 31, 2011
	(in millions)	
Cash Flow Hedges, Net of Tax	$ (38)	$ (23)
Securities Available for Sale, Net of Tax	4	2
Amortization of Pension and OPEB Deferred Costs, Net of Tax	112	81
Pension and OPEB Funded Status, Net of Tax	(415)	(530)
Total	$ (337)	$ (470)

Stock-Based Compensation Plans

As of December 31, 2012, we had stock options, performance units and restricted stock units outstanding under The Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP). This plan was last approved by shareholders in April 2010.

We maintain a variety of tax qualified and nonqualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP common stock. This includes career share accounts maintained under the American Electric Power System Stock Ownership Requirement Plan, which facilitates executives in meeting minimum stock ownership requirements assigned to them by the Human Resources Committee of the Board of Directors. Career shares are derived from vested performance units granted to employees under the LTIP. Career shares are equal in value to shares of AEP common stock and do not become payable to executives until after their service ends. Dividends paid on career shares are reinvested as additional career shares.

We compensate our non-employee directors, in part, with stock units under the American Electric Power Company, Inc. Stock Unit Accumulation Plan for Non-Employee Directors. These stock units become payable in cash to directors after their service ends.

In January 2006, we adopted accounting guidance for "Compensation - Stock Compensation" which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors, including stock options, based on estimated fair values.

We recognize compensation expense for all share-based awards with service only vesting conditions granted on or after January 2006 using the straight-line single-option method. Stock-based compensation expense recognized on the statements of income for the years ended December 31, 2012, 2011 and 2010 is based on awards ultimately expected to vest. Therefore, stock-based compensation expense has been reduced to reflect estimated forfeitures. Accounting guidance for "Compensation - Stock Compensation" requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

For the years ended December 31, 2012, 2011 and 2010, compensation expense is included in Net Income for the performance units, career shares, restricted shares, restricted stock units and the non-employee director's stock units. See Note 14 for additional discussion.

Earnings Per Share (EPS)

Shown below are income statement amounts attributable to AEP common shareholders:

Amounts Attributable to AEP Common Shareholders	Years Ended December 31, 2012	2011	2010
		(in millions)	
Income Before Extraordinary Item	$ 1,259	$ 1,568	$ 1,211
Extraordinary Item, Net of Tax	-	373	-
Net Income	$ 1,259	$ 1,941	$ 1,211

Basic earnings per common share is calculated by dividing net earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

The following table presents our basic and diluted EPS calculations included on the statements of income:

	Years Ended December 31, 2012		2011		2010	
	(in millions, except per share data)					
		$/share		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 1,259		$ 1,941		$ 1,211	
Weighted Average Number of Basic Shares Outstanding	484.7	$ 2.60	482.2	$ 4.02	479.4	$ 2.53
Weighted Average Dilutive Effect of:						
Performance Share Units	-	-	-	-	0.1	-
Stock Options	-	-	0.1	-	-	-
Restricted Stock Units	0.4	-	0.2	-	0.1	-
Weighted Average Number of Diluted Shares Outstanding	485.1	$ 2.60	482.5	$ 4.02	479.6	$ 2.53

Options to purchase 136,250 shares of common stock as of December 31, 2010 were not included in the computation of diluted earnings per share attributable to AEP common shareholders. Since the options' exercise prices were greater than the average market price of the common shares, the effect would have been antidilutive. There were no antidilutive shares outstanding as of December 31, 2012 and 2011.

OPCo Revised Depreciation Rates

Effective December 1, 2011, we revised book depreciation rates for certain of OPCo's generating plants consistent with shortened depreciable lives for the generating units. This change in depreciable lives resulted in a $52 million increase in depreciation expense in 2012.

In the fourth quarter of 2012, OPCo impaired certain generating units, including those discussed above (see Note 6). As a result of this impairment of the full book value of these assets, OPCo ceased depreciation on these generating units effective December 1, 2012.

Supplementary Related Party Information

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2012, AEP's ownership and investment in OVEC were 43.47% and $4.4 million, respectively.

OVEC's owners are members to an intercompany power agreement. Participants of this agreement are entitled to receive and obligated to pay for all OVEC generating capacity, approximately 2,200 MWs, in proportion to their respective power participation ratios. The aggregate power participation ratio of certain AEP utility subsidiaries is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and provide a return on capital. In 2011, the intercompany power agreement was extended until June 2040.

AEP and other nonaffiliated owners authorized environmental investments related to their ownership interests and OVEC's Board of Directors authorized capital expenditures totaling $1.4 billion in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at OVEC's two generating plants. As of December 31, 2012, OVEC completed financing of $1.4 billion required for these environmental projects through debt issuances. As of December 31, 2012, one plant was operating with new environmental controls and the other plant is scheduled to be operational with new environmental controls during the second quarter of 2013.

The following details related party transactions for the years ended December 31, 2012, 2011 and 2010:

Related Party Transactions	Years Ended December 31, 2012	2011	2010
		(in millions)	
AEP Consolidated Revenues – Utility Operations:			
OVEC	$ -	$ -	$ (20)(a)
AEP Consolidated Revenues – Other Revenues:			
OVEC – Barging and Other Transportation Services	30	37	29
AEP Consolidated Expenses – Purchased Electricity for Resale:			
OVEC	273	383 (b)	302 (b)

(a) The parties to the Interconnection Agreement purchased power from OVEC to serve off-system sales through an agreement that began in January 2010 and ended in June 2010.
(b) The parties to the Interconnection Agreement purchased power from OVEC to serve retail sales in 2011 and 2010. The total amount reported in 2011 and 2010 includes $66 million and $10 million, respectively, related to these agreements.

Supplementary Cash Flow Information

Cash Flow Information	Years Ended December 31, 2012	2011	2010
		(in millions)	
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 931	$ 900	$ 958
Income Taxes	(82)	(118)	(268)
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	63	54	225
Construction Expenditures Included in Current Liabilities as of December 31,	439	380	267
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	35	1	-
Assumption of Liabilities Related to Acquisitions	56	-	-
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	30	-	-

2. EXTRAORDINARY ITEM

TCC Texas Restructuring

In February 2006, the PUCT issued an order that denied recovery of capacity auction true-up amounts. Based on the February 2006 PUCT order, TCC recorded the disallowance as a $421 million ($273 million, net of tax) extraordinary loss in the December 31, 2005 financial statements. In July 2011, the Supreme Court of Texas reversed the PUCT's February 2006 disallowance of capacity auction true-up amounts and remanded for reconsideration the treatment of certain tax balances under normalization rules. Based upon the Supreme Court of Texas reversal of the PUCT's capacity auction true-up disallowance, TCC recorded a pretax gain of $421 million ($273 million, net of tax) in Extraordinary Item, Net of Tax on the statements of income in 2011.

Following a remand proceeding, the PUCT allowed TCC to retain contested tax balances in full satisfaction of its true-up proceeding, including carrying charges. Based upon the PUCT order, TCC recorded the reversal of regulatory credits of $65 million ($42 million, net of tax) and the reversal of $89 million of accumulated deferred investment tax credits ($58 million, net of tax) in Extraordinary Item, Net of Tax on the statements of income in 2011.

3. RATE MATTERS

Our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. Rate matters can have a material impact on net income, cash flows and possibly financial condition. Our recent significant rate orders and pending rate filings are addressed in this note.

OPCo Rate Matters

Ohio Electric Security Plan Filing

2009 – 2011 ESP

The PUCO issued an order in March 2009 that modified and approved the ESP which established rates at the start of the April 2009 billing cycle through 2011. OPCo collected the 2009 annualized revenue increase over the last nine months of 2009. The order also provided a phase-in FAC, which was authorized to be recovered through a non-bypassable surcharge over the period 2012 through 2018. The PUCO's March 2009 order was appealed to the Supreme Court of Ohio, which issued an opinion and remanded certain issues back to the PUCO.

In October 2011, the PUCO issued an order in the remand proceeding. As a result, OPCo ceased collection of POLR billings in November 2011 and recorded a write-off in 2011 related to POLR collections for the period June 2011 through October 2011. In February 2012, the Ohio Consumers' Counsel and the IEU filed appeals of that order with the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge, which, if ordered, could reduce OPCo's net deferred fuel costs up to the total balance. As of December 31, 2012, OPCo's net deferred fuel balance was $519 million, excluding unrecognized equity carrying costs. A decision from the Supreme Court of Ohio is pending.

In January 2011, the PUCO issued an order on the 2009 SEET filing, which resulted in a write-off in 2010 and a subsequent refund to customers during 2011. The IEU and the Ohio Energy Group filed appeals with the Supreme Court of Ohio challenging the PUCO's SEET decision. In December 2012, the Supreme Court of Ohio issued an order which rejected all of the intervenors' challenges and affirmed the PUCO decision.

The 2009 SEET order gave consideration for a future commitment to invest $20 million to support the development of a large solar farm. In January 2013, the PUCO found there was not a need for the large solar farm. The PUCO noted that OPCo remains obligated to spend $20 million on this solar project or another similar project by the end of 2013.

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. Subsequent testimony and legal briefs from intervenors recommended a refund of up to $62 million of 2010 earnings, which included off-system sales in the SEET calculation. In December 2011, the PUCO staff filed testimony that recommended a $23 million refund of 2010 earnings. OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO ordered SEET refund. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. The PUCO approved OPCo's request to file the 2011 SEET one month after the PUCO issues an order on the 2010 SEET. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo and in 2012 for OPCo.

Management is unable to predict the outcome of the unresolved litigation discussed above. If these proceedings result in adverse rulings, it could reduce future net income and cash flows and impact financial condition.

January 2012 – May 2016 ESP as Rejected by the PUCO

In December 2011, the PUCO approved an ESP modified stipulation which established a SSO pricing for generation. Various parties filed for rehearing with the PUCO requesting that the PUCO reconsider adoption of the modified stipulation. In February 2012, the PUCO issued an entry on rehearing which rejected the modified stipulation and ordered a return to the 2011 ESP rates. Those rates remained in effect until the new ESP was approved in August 2012. See the "June 2012 – May 2015 ESP Including Capacity Charge" section below.

As a result of the PUCO's rejection of the modified stipulation, OPCo reversed a $35 million obligation to contribute to the Partnership with Ohio and the Ohio Growth Fund and an $8 million regulatory asset for 2011 storm damage, both originally recorded in 2011.

As directed by the February 2012 order, OPCo filed revised tariffs with the PUCO to implement the provisions of the 2011 ESP. Included in the revised tariffs was the Phase-In Recovery Rider (PIRR) to recover deferred fuel costs as authorized under the 2009 – 2011 ESP order. In March 2012, the PUCO issued an order that directed OPCo to file new revised tariffs removing the PIRR and stated that its recovery would be addressed in a future proceeding. OPCo implemented the new revised tariffs in March 2012. In March 2012, OPCo resumed recording a weighted average cost of capital return on the deferred fuel balance in accordance with the 2009 - 2011 ESP order. OPCo also filed a request for rehearing of the March 2012 order relating to the PIRR, which the PUCO denied but provided that all of the substantive concerns and issues raised would be addressed in a separate PIRR docket.

In August 2012, the PUCO ordered implementation of PIRR rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. The August 2012 order was upheld on rehearing by the PUCO in October 2012. In November 2012, OPCo filed an appeal at the Supreme Court of Ohio claiming a long-term debt rate modified the previously adjudicated ESP order, which granted a weighted average cost of capital rate. The IEU and the Ohio Consumers' Counsel also filed appeals at the Supreme Court of Ohio in November 2012 arguing that the PUCO should have reduced the deferred fuel balance to reflect the prior "improper" collection of POLR revenues and reduced carrying costs due to an accumulated deferred income tax credit. See the "2009 – 2011 ESP" section above. These appeals could reduce OPCo's net deferred fuel balance up to the total balance, which would reduce future net income and cash flows. A decision from the Supreme Court of Ohio is pending.

June 2012 – May 2015 ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that establishes base generation rates through May 2015, adopted a 12% earnings threshold for the SEET and allowed the continuation of the fuel adjustment clause. Further, the ESP established a non-bypassable Distribution Investment Rider effective September 2012 through May 2015 to recover, with certain caps, post-August 2010 distribution investment. The ESP also maintained recovery of several previous ESP riders and required OPCo to contribute $2 million per year during the ESP to the Ohio Growth Fund. In addition, the PUCO approved a storm damage recovery mechanism.

As part of the ESP decision, the PUCO ordered OPCo to conduct an energy-only auction for 10% of the SSO load with delivery beginning six months after the receipt of final orders in both the ESP and corporate separation cases and extending through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 50% of the SSO load with delivery beginning June 2014 through May 2015 and for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. OPCo will conduct energy and capacity auctions for its entire SSO load for delivery starting in June 2015.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The RPM price is approximately $20/MW day through May 2013. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio.

As part of the August 2012 PUCO ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is intended to provide approximately $500 million over the ESP period and will be collected from customers at $3.50/MWh through May 2014 and $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the deferred capacity costs. As of December 31, 2012, OPCo recorded $66 million of incurred deferred capacity costs, including debt carrying costs, in Regulatory Assets on the balance sheet. In August 2012, the IEU filed an action with the Supreme Court of Ohio stating, among other things, that OPCo's collection of its capacity costs is illegal. In September 2012, OPCo and the PUCO filed motions to dismiss the IEU's action. If OPCo is ultimately not permitted to fully collect its deferred capacity costs, it would reduce future net income and cash flows and impact financial condition. A decision from the Supreme Court of Ohio is pending.

In January 2013, the PUCO issued its Order on Rehearing for the ESP which generally upheld its August 2012 order including the implementation of the RSR. The PUCO clarified that a final reconciliation of revenues and costs would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket. If OPCo is ultimately not permitted to fully collect its ESP rates, including the RSR, it would reduce future net income and cash flows and impact financial condition.

Corporate Separation

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo's generation assets including the transfer of OPCo's generation assets at net book value to AEPGenCo. AEPGenCo will also assume the associated generation liabilities. In December 2012, the PUCO granted the IEU and Ohio Consumers' Counsel requests for rehearing for the purpose of further consideration and those requests remain pending.

Also in October 2012, filings at the FERC were submitted related to corporate separation. See the "Corporate Separation and Termination of Interconnection Agreement" section below under FERC Rate Matters. Our results of operations related to generation in Ohio will be largely determined by prevailing market conditions.

2011 Ohio Distribution Base Rate Case

In December 2011, the PUCO approved a stipulation which provided for no change in distribution rates and a new rider for a $15 million annual credit to residential ratepayers due principally to the inclusion of the rate base distribution investment in the Distribution Investment Rider (DIR) as approved in December 2011 by the modified stipulation in the ESP proceeding. However, when the February 2012 PUCO order rejected the ESP modified stipulation, collection of the DIR terminated. In August 2012, the PUCO approved a new DIR as part of the June 2012 – May 2015 ESP proceeding. The DIR is capped at $86 million in 2012, $104 million in 2013, $124 million in 2014 and $52 million for the period January through May 2015, for a total of $366 million.

Storm Damage Recovery Rider (SDRR)

In December 2012, OPCo submitted an application with the PUCO to establish initial SDRR rates. The SDRR seeks recovery of 2012 incremental storm distribution expenses over twelve months starting with the effective date of the SDRR as approved by the PUCO. If the PUCO extends recovery beyond twelve months and/or does not commence cost recovery by April 2013, OPCo requested approval of a weighted average cost of capital carrying charge, effective April 2013. As of December 31, 2012, OPCo recorded $62 million in Regulatory Assets on the balance sheet related to 2012 storm damage. If OPCo is not ultimately permitted to recover these storm costs, it would reduce future net income and cash flows and impact financial condition.

2009 Fuel Adjustment Clause Audit

The PUCO selected an outside consultant to conduct an audit of OPCo's FAC for 2009. The outside consultant provided its audit report to the PUCO. In January 2012, the PUCO ordered that the remaining $65 million in proceeds from a 2008 coal contract settlement agreement be applied against OPCo's under-recovered fuel balance. In April 2012, on rehearing, the PUCO ordered that the settlement credit only needed to reflect the Ohio retail jurisdictional share of the gain not already flowed through the FAC with carrying charges. OPCo recorded a $30 million net favorable adjustment on the statement of income in the second quarter of 2012. The January 2012 PUCO order also stated that a consultant should be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers. Management is unable to predict the outcome of any future consultant recommendation. If the PUCO ultimately determines that additional amounts should benefit ratepayers as a result of the consultant's review of the coal reserve valuation, it could reduce future net income and cash flows and impact financial condition.

In August 2012, intervenors filed with the Supreme Court of Ohio claiming the settlement credit ordered by the PUCO should have reflected the remaining gain not already flowed through the FAC with carrying charges, which, if ordered, would be $35 million plus carrying charges. If the Supreme Court of Ohio ultimately determines that additional amounts should benefit ratepayers, it could reduce future net income and cash flows and impact financial condition.

2010 and 2011 Fuel Adjustment Clause Audits

The PUCO-selected outside consultant issued its 2010 and 2011 FAC audit reports which included a recommendation that the PUCO reexamine the carrying costs on the deferred FAC balance and determine whether the carrying costs on the balance should be net of accumulated income taxes. As of December 31, 2012, the amount of OPCo's carrying costs that could potentially be reduced due to the accumulated income tax issue is estimated to be approximately $36 million, including $19 million of unrecognized equity carrying costs. These amounts include the carrying costs exposure of the 2009 FAC audit, which has been appealed by an intervenor to the Supreme Court of Ohio. Decisions from the PUCO are pending. Management is unable to predict the outcome of these proceedings. If the PUCO orders result in a reduction to the FAC deferral, it would reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

OPCo and Ormet, a large aluminum company, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. This interim arrangement was approved by the PUCO and was effective from January 2009 through September 2009. In March 2009, the PUCO approved a FAC in the ESP filing and the FAC aspect of the ESP order was upheld by the Supreme Court of Ohio. The approval of the FAC as part of the ESP, together with the PUCO approval of the interim arrangement, provided the basis to record a regulatory asset for the difference between the approved market price and the rate paid by Ormet. Through September 2009, the last month of the interim arrangement, OPCo had $64 million of deferred FAC costs related to the interim arrangement, excluding $2 million of unrecognized equity carrying costs. In November 2009, OPCo requested that the PUCO approve recovery of the deferral under the interim agreement plus a weighted average cost of capital carrying charge. The deferral amount is included in OPCo's FAC phase-in deferral balance. In the 2009 – 2011 ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related regulatory asset and requested that the PUCO prevent OPCo from collecting the Ormet-related revenues in the future. The PUCO did not take any action on this request. The intervenors raised the issue again in response to OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement. This issue remains pending before the PUCO. If OPCo is not ultimately permitted to fully recover its requested deferrals under the interim arrangement, it would reduce future net income and cash flows and impact financial condition.

Special Rate Mechanism for Ormet

In October 2012, the PUCO issued an order approving a delayed payment plan for Ormet of its October and November 2012 power billings totaling $27 million to be paid in equal monthly installment over the period January 2014 to May 2015 without interest. In the event Ormet does not pay the $27 million, the PUCO permitted OPCo to recover the unpaid balance, up to $20 million, in the economic development rider. To the extent unpaid amounts exceed $20 million, it will reduce future net income and cash flows.

Ohio IGCC Plant

In March 2005, OPCo filed an application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. As of December 31, 2012, OPCo has collected $24 million in pre-construction costs authorized in a June 2006 PUCO order. Intervenors have filed motions with the PUCO requesting all collected pre-construction costs be refunded to Ohio ratepayers with interest.

Management cannot predict the outcome of these proceedings concerning the Ohio IGCC plant or what effect, if any, these proceedings would have on future net income and cash flows. However, if OPCo is required to refund pre-construction costs collected, it could reduce future net income and cash flows and impact financial condition.

SWEPCo Rate Matters

Turk Plant

SWEPCo constructed the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which was placed into service in December 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and operates the completed facility. As of December 31, 2012, excluding costs attributable to its joint owners and a $62 million provision for a Texas capital costs cap, SWEPCo has capitalized approximately $1.7 billion of expenditures, including AFUDC and capitalized interest of $328 million and related transmission costs of $120 million.

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the 88 MW SWEPCo Arkansas jurisdictional share of the Turk Plant. Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. In June 2010, in response to the Arkansas Supreme Court's decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This portion of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the SPP market.

The PUCT approved a Certificate of Convenience and Necessity (CCN) for the Turk Plant with the following conditions: (a) a cap on the recovery of jurisdictional capital costs for the Turk Plant based on the previously estimated $1.522 billion projected construction cost, excluding AFUDC and related transmission costs, (b) a cap on recovery of annual CO_2 emission costs at $28 per ton through the year 2030 and (c) a requirement to hold Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers. SWEPCo appealed the PUCT's order contending the two cost cap restrictions are unlawful. The Texas Industrial Energy Consumers (TIEC) filed an appeal contending that the PUCT's grant of a conditional CCN for the Turk Plant should be revoked because the Turk Plant is unnecessary to serve retail customers. The Texas District Court and the Texas Court of Appeals affirmed the PUCT's order in all respects. In April 2012, SWEPCo and TIEC filed petitions for review at the Supreme Court of Texas. The Supreme Court of Texas has requested full briefing from the parties.

If SWEPCo cannot recover all of its investment and expenses related to the Turk Plant, it would reduce future net income and cash flows and impact financial condition.

2012 Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates by $83 million, primarily due to the Turk Plant, based upon an 11.25% return on common equity to be effective January 2013. The requested base rate increase included a return on and of the Texas jurisdictional share (approximately 33%) of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operation and maintenance costs. The filing also (a) increased depreciation expense due to the decrease in the average remaining life of the Welsh Plant to account for the change in the retirement date of the Welsh Plant Unit 2 from 2040 to 2016, (b) proposed increased vegetation management expenditures and (c) included a return on and of the Stall Unit as of December 2011 and associated operations and maintenance costs.

In September 2012, an Administrative Law Judge issued an order that granted the establishment of SWEPCo's existing rates as temporary rates beginning in late January 2013, subject to true-up to the final PUCT-approved rates.

In December 2012, several intervenors, including the PUCT staff, filed testimony that recommended an annual base rate increase between $16 million and $51 million based upon a return on common equity between 9.0% and 9.55%. In addition, two intervenors recommended that the Turk Plant be excluded from rate base. A decision from the PUCT is expected in the second quarter of 2013. If the PUCT does not approve full cost recovery of SWEPCo's assets, it would reduce future net income and cash flows and impact financial condition.

Louisiana 2012 Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share (approximately 29%) of the Turk Plant. In February 2013, a settlement was filed and a hearing was conducted. The settlement provided that SWEPCo would increase Louisiana total rates by approximately $2 million annually, effective March 2013, consisting of an increase in base rates of approximately $85 million annually offset by a decrease in fuel rates of approximately $83 million annually. The proposed March 2013 base rates are based on a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund based on the staff review of the cost of service and prudence review of the Turk Plant to be initiated by SWEPCo no later than May 2013. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover all non-fuel Turk Plant costs and a full weighted-average cost of capital return on the Turk Plant portion of rate base beginning January 2013. A decision from the LPSC is expected in the first quarter of 2013.

Flint Creek Plant Environmental Controls

In February 2012, SWEPCo filed a petition with the APSC seeking a declaratory order to install environmental controls at the Flint Creek Plant to comply with the standards established by the CAA. The estimated cost of the project is $408 million, excluding AFUDC and company overheads. As a joint owner of the Flint Creek Plant, SWEPCo's portion of those costs is estimated at $204 million. As of December 31, 2012, SWEPCo has incurred $11 million related to this project, including AFUDC and company overheads. The APSC staff and the Sierra Club filed testimony that recommended the APSC deny the requested declaratory order. A hearing is scheduled for March 2013. If SWEPCo is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

APCo and WPCo Rate Matters

Plant Transfers

In October 2012, the AEP East Companies submitted several filings with the FERC. See the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters. In December 2012, APCo and WPCo filed requests with the Virginia SCC and the WVPSC for approval to transfer at net book value to APCo a two-thirds interest in Amos Plant, Unit 3 and a one-half interest in the Mitchell Plant, comprising 1,647 MW of average annual generating capacity presently owned by OPCo. Hearings at the Virginia SCC and the WVPSC are scheduled for April 2013 and July 2013, respectively. If the transfers are approved, APCo and WPCo anticipate seeking cost recovery when they file their next base rate cases.

Virginia Fuel Filing

In April 2012, APCo filed an application with the Virginia SCC for an annual increase in fuel revenues of $117 million to be effective June 2012. The filing included forecasted costs for the 15-month period ended August 2013 and requested recovery of APCo's anticipated unrecovered fuel balance as of May 2012 over a two-year period commencing in June 2012. The non-incremental portion of APCo's forecasted and deferred wind purchased power costs were reflected in APCo's filing. In June 2012, the Virginia SCC approved the application as filed.

Environmental Rate Adjustment Clause (Environmental RAC)

In November 2011, the Virginia SCC issued an order which approved APCo's Environmental RAC recovery of $30 million to be collected over one year beginning in February 2012 but denied recovery of certain environmental costs. As a result, in 2011, APCo recorded a pretax write-off of $31 million on the statement of income related to environmental compliance costs incurred from January 2009 through December 2010. APCo appealed the Virginia SCC decision to the Supreme Court of Virginia. In November 2012, the Supreme Court of Virginia issued an order which allowed APCo to recover an additional $6 million of 2009 and 2010 actual Environmental RAC costs and affirmed the portion of the November 2011 order that denied recovery of certain environmental costs. The Virginia SCC issued an order in December 2012 which permitted APCo to extend the current Environmental RAC surcharge for the months of February and March 2013 in order to collect the $6 million.

Generation Rate Adjustment Clause (Generation RAC)

In January 2012, the Virginia SCC issued a Generation RAC order which allowed APCo to recover $26 million annually, effective March 2012, related to recovery of the Dresden Plant. APCo filed with the Virginia SCC to continue the current Generation RAC rate to recover costs of the Dresden Plant through February 2014. In December 2012, the Virginia SCC granted APCo's application as filed and required APCo to submit a new Generation RAC filing in March 2013.

APCo IGCC Plant

As of December 31, 2012, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to its West Virginia jurisdiction, approximately $2 million applicable to its FERC jurisdiction and approximately $9 million applicable to its Virginia jurisdiction. If the costs are not recoverable, it would reduce future net income and cash flows and impact financial condition.

APCo's and WPCo's Expanded Net Energy Charge (ENEC) Filing

In March 2012, West Virginia passed securitization legislation, which allows the WVPSC to establish a regulatory framework to securitize certain deferred ENEC balances and other ENEC related assets. Also in March 2012, APCo and WPCo filed their ENEC application with the WVPSC for the fourth year of a four-year phase-in plan which requested no change in ENEC rates if the WVPSC issues a financing order allowing securitization of the under-recovered ENEC deferral and other ENEC-related assets. If the financing order is not issued, APCo and WPCo requested that recovery of these costs be allowed in current rates.

In July 2012, the WVPSC issued an order that approved a settlement agreement which recommended no change in total ENEC rates but reflected a $24 million increase in the construction surcharge and a $24 million decrease in ENEC rates. In August 2012, APCo and WPCo filed with the WVPSC a request for a financing order to securitize a total of $422 million related to the December 2011 under-recovered ENEC deferral balance including other ENEC-related assets of $13 million and related future financing costs of $7 million. Upon completion of the securitization, APCo would offset its current ENEC rates by an amount to recover the securitized balance over the securitization period. In January 2013, intervenors filed testimony that recommended securitization of approximately $370 million. The differences between APCo's and WPCo's request and the intervenors' testimony represent previously approved ENEC-related deferred amounts being recovered in the ENEC over extended periods, various amounts deferred subsequent to the 2011 securitization period and related future securitization financing costs. As of December 31, 2012, APCo's ENEC under-recovery balance of $299 million, net of 2012 over-recovery, was recorded in Regulatory Assets on the balance sheet, excluding $4 million of unrecognized equity carrying costs and $12 million of other ENEC-related assets. APCo and WPCo are currently in settlement discussions with intervenors.

PSO Rate Matters

PSO 2008 Fuel and Purchased Power

In 2009, the OCC initiated a proceeding to review PSO's fuel and purchased power adjustment clause for the calendar year 2008 and also initiated a prudence review of the related costs. In October 2012, the OCC issued a final order that found PSO's fuel and purchased power costs were prudently incurred without any disallowance and that PSO's shareholder's portion of off-system sales margins would remain at 25%.

Oklahoma Environmental Compliance Plan

In September 2012, PSO filed an environmental compliance plan with the OCC reflecting the retirement of Northeastern Station (NES) Unit 4 in 2016 and additional environmental controls on NES Unit 3 to continue operations through 2026. The plan requested approval for (a) cost recovery through base rates by 2026 of an estimated $256 million of new environmental investment that will be incurred prior to 2016 at NES Unit 3, (b) cost recovery through 2026 of NES Units 3 and 4 net book value (combined net book value of the two units is $234 million as of December 31, 2012), (c) cost recovery through base rates of an estimated $83 million of new investment incurred through 2016 at various gas units and (d) a new 15-year purchase power agreement (PPA) with a nonaffiliated entity, effective in 2016, with cost recovery through a rider, including an annual earnings component of $3 million. Although the environmental compliance plan does not seek to put any new costs into rates at this time, PSO anticipates seeking cost recovery when filing its next base rate case, which is expected to occur no later than 2014.

In January 2013, testimony filed by the OCC staff and the Oklahoma Office of the Attorney General generally agreed with PSO's plan, although they recommended no earnings component on the PPA and to delay final decisions on parts of the plan including cost recovery of NES Unit 3 and any increases in fuel costs due to reductions in the output of energy from NES Unit 3 beginning in 2021. The testimony recommended that cost recovery could extend past 2026 on parts of the plan and recommended a $175 million cost cap on NES Unit 3 environmental investment.

Also, an intervenor representing some of PSO's large industrial users opposed virtually all of PSO's plan, including recommending no cost recovery of NES Units 3 and 4 book value amounts not recovered at the time of their retirement and no recovery of the PPA costs, including earnings on the PPA. A hearing is scheduled for April 2013.

I&M Rate Matters

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 $149 million net annual increase reflects an increase in base rates of $178 million offset by proposed corresponding reductions of $13 million to the off-system sales sharing rider, $9 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The request included an increase in depreciation rates that would result in an increase of approximately $25 million in annual depreciation expense. Included in the depreciation rates increase was a decrease in the average remaining life of Tanners Creek Plant to account for the change in the retirement date of Tanners Creek Plant, Units 1-3 from 2020 to 2014. In May 2012, I&M filed rebuttal testimony which changed the retirement date for Tanners Creek Plant, Units 1-3 to 2015 and supported an increase of $170 million in base rates, excluding reductions to certain riders.

In February 2013, the IURC issued an order that granted an $85 million annual increase in base rates based upon a return on common equity of 10.2%, effective March 2013. The $85 million annual increase in base rates will be offset by corresponding reductions of $5 million to the off-system sales sharing rider, $11 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The IURC granted the requested increase in depreciation rates, modified the shareholder's portion of off-system sales margins to 50% below and above the $27 million imbedded in base rates, established a capacity tracker and established a major storm damage restoration reserve.

Cook Plant Life Cycle Management Project

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its licensed life. The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC.

In Indiana, I&M requested recovery of certain project costs, including interest, through a new rider effective January 2013. In Michigan, I&M requested that the MPSC approve a Certificate of Need and authorize I&M to defer, on an interim basis, incremental depreciation and related property tax costs, including interest, along with study, analysis and development costs until the applicable LCM costs are included in I&M's base rates. As of December 31, 2012, I&M has incurred $176 million related to the LCM Project, including AFUDC.

In August 2012, intervenors filed testimony in Indiana. The Indiana Michigan Power Company Industrial Group recommended that I&M recover $229 million in a rider with the remaining costs to be requested in future base rate cases. The Indiana Office of Utility Consumer Counselor (OUCC) recommended a maximum of $408 million of LCM project costs be recovered in a rider, and a maximum of $299 million for projects the OUCC believes are not related to LCM to be recovered in future base rates. The IURC held a hearing in January 2013.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project with total costs of $851 million (Michigan jurisdictional share is approximately 15%) for the period 2013 through 2018. The order provided that depreciation, property taxes and a return using the overall rate of return approved in I&M's last Michigan base rate case related to the 2013 through 2018 LCM Project costs can be deferred until these costs are included in rates. The order excluded from the CON $176 million of LCM costs spent prior to 2013 as $39 million was included in the determination of Michigan base rates, effective April 2012, and the remaining $137 million in CWIP will be requested in a future base rate case. The order also excluded $142 million of future LCM costs, which if incurred, will be requested in a future base rate case. Under Michigan law, the approved CON amount is eligible for a cost increase allowance of 10%, up to $85 million, of the approved project costs in the event project costs exceed the approved level of costs.

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

Rockport Plant Environmental Controls

I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit one unit at its Rockport Plant with environmental controls estimated to cost $1.4 billion to comply with new requirements. AEGCo and I&M jointly own Unit 1 and jointly lease Unit 2 of the Rockport Plant. I&M is also evaluating options related to the maturity of the lease for Rockport Plant Unit 2 in 2022 and continues to investigate alternative compliance technologies for these units as part of its overall compliance strategy. As of December 31, 2012, we have incurred $71 million related to these environmental controls, including AFUDC. If we are not ultimately permitted to recover our incurred costs, it would reduce future net income and cash flows.

In February 2013, I&M filed a motion with the IURC to dismiss its request for approval of a CPCN for environmental controls after modification to the NSR consent decree. Under the terms of the NSR consent decree modification, the units of Rockport Plant will be equipped with dry sorbent injection systems in 2015 and have options to retrofit additional SO_2 controls, refuel, repower or retire in 2025 and 2028.

KPCo Rate Matters

Plant Transfer

In October 2012, the AEP East Companies submitted several filings with the FERC. See the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters. In December 2012, KPCo filed a request with the KPSC for approval to transfer at net book value to KPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity presently owned by OPCo. If the transfer is approved, KPCo anticipates seeking cost recovery when filing its next base rate case. In addition, KPCo announced its plan to retire Big Sandy Plant, Unit 2 in early 2015, subject to regulatory approval, and its intention to study the conversion of Big Sandy Plant, Unit 1 to burn natural gas instead of coal.

Big Sandy Plant, Unit 2 FGD System

In May 2012, KPCo withdrew its application to the KPSC seeking approval of a Certificate of Public Convenience and Necessity to retrofit Big Sandy Plant, Unit 2 with a dry FGD system. As part of the Mitchell Plant transfer filing discussed above, KPCo requested costs related to the FGD project be established as a regulatory asset and recovered in KPCo's next base rate case. As of December 31, 2012, KPCo has incurred $29 million related to the FGD project, which is recorded in Deferred Charges and Other Noncurrent Assets on the balance sheet. If KPCo is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

FERC Rate Matters

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. 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. In August 2010, the affected companies, including the AEP East Companies, filed a compliance filing with the FERC. The AEP East Companies provided reserves for net refunds for SECA settlements. The AEP East Companies settled with various parties prior to the FERC compliance filing and entered into additional settlements subsequent to the compliance filing being filed at the FERC. Based on the analysis of the May 2010 order, the compliance filing and recent settlements, management believes that the reserve is adequate to pay the refunds, including interest, and any remaining exposure beyond the reserve is immaterial.

Corporate Separation and Termination of Interconnection Agreement

In October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generation assets from its distribution and transmission operations. The filings requested approval to transfer at net book value approximately 9,200 MW of OPCo-owned generation assets to a new wholly-owned company, AEPGenCo. The AEP East Companies also requested FERC approval to transfer at net book value OPCo's current two-thirds ownership (867 MW) in Amos Plant, Unit 3 to APCo and transfer at net book value OPCo's Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each). Additionally, the AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement among APCo, I&M and KPCo. Intervenors have opposed several of these filings. The AEP East Companies have responded and continue to pursue approvals from the FERC. A decision from the FERC is expected in mid-2013.

Similar filings have been made at the KPSC, the Virginia SCC and the WVPSC. See the "Plant Transfers" section of APCo and WPCo Rate Matters and the "Plant Transfer" section of KPCo Rate Matters.

4. EFFECTS OF REGULATION

Regulatory assets are comprised of the following items:

	December 31, 2012	December 31, 2011	Remaining Recovery Period
Current Regulatory Assets	(in millions)		
Under-recovered Fuel Costs - earns a return	$ 86	$ 56	1 year
Under-recovered Fuel Costs - does not earn a return	2	9	1 year
Total Current Regulatory Assets	$ 88	$ 65	
Noncurrent Regulatory Assets			
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:			
Regulatory Assets Currently Earning a Return			
Storm Related Costs	$ 23	$ 24	
Economic Development Rider	13	13	
Other Regulatory Assets Not Yet Being Recovered	1	-	
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	172	10	
Virginia Environmental Rate Adjustment Clause	29	18	
Mountaineer Carbon Capture and Storage Product Validation Facility	14	14	
Litigation Settlement	11	11	
Deferred Wind Power Costs	5	38	
Special Rate Mechanism for Century Aluminum	-	13	
Other Regulatory Assets Not Yet Being Recovered	36	14	
Total Regulatory Assets Not Yet Being Recovered	304	155	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Ohio Fuel Adjustment Clause	519	521	6 years
West Virginia Expanded Net Energy Charge	273	327	(a)
Ohio Deferred Asset Recovery Rider	152	173	6 years
Unamortized Loss on Reacquired Debt	82	92	31 years
Ohio Capacity Deferral	66	-	6 years
Transmission Cost Recovery Rider	49	28	3 years
Meter Replacement Costs	47	39	10 years
Storm Related Costs	36	65	6 years
RTO Formation/Integration Costs	15	18	7 years
Red Rock Generating Facility	10	10	44 years
Economic Development Rider	5	12	1 year
Capacity Auction True-Up	-	692	
Other Regulatory Assets Being Recovered	10	15	various
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	1,896	2,308	12 years
Income Taxes, Net	1,353	1,237	44 years
Postemployment Benefits	45	47	5 years
Virginia Transmission Rate Adjustment Clause	33	20	2 years
Cook Nuclear Plant Refueling Outage Levelization	27	41	3 years
Storm Related Costs	27	35	6 years
West Virginia Expanded Net Energy Charge	26	32	(a)
Distribution Decoupling	16	-	2 years
Deferred Restructuring Costs	15	18	6 years
Deferred PJM Fees	14	22	2 years
Vegetation Management	13	11	1 year
Peak Demand Reduction/Energy Efficiency	12	8	1 year
Asset Retirement Obligation	9	14	8 years
Virginia Environmental Rate Adjustment Clause	8	24	1 year
Unrealized Loss on Forward Commitments	8	16	2 years
Restructuring Transition Costs	5	8	4 years
Other Regulatory Assets Being Recovered	31	38	various
Total Regulatory Assets Being Recovered	4,802	5,871	
Total Noncurrent Regulatory Assets	$ 5,106	$ 6,026	

(a) Request for securitization is pending from the WVPSC to recover $422 million as securitized transition assets from ratepayers over the securitization bond period.

Regulatory liabilities are comprised of the following items:

	December 31, 2012	December 31, 2011	Remaining Refund Period
Current Regulatory Liabilities	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 25	$ 5	1 year
Over-recovered Fuel Costs - does not pay a return	22	3	1 year
Total Current Regulatory Liabilities	$ 47	$ 8	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities not yet being paid:			
Regulatory Liabilities Currently Paying a Return			
Louisiana Refundable Construction Financing Costs	$ 96	$ 53	
Other Regulatory Liabilities Not Yet Being Paid	4	5	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Not Yet Being Paid	9	8	
Total Regulatory Liabilities Not Yet Being Paid	109	66	
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	2,511	2,270	(a)
Advanced Metering Infrastructure Surcharge	83	78	8 years
Deferred Investment Tax Credits	23	27	48 years
Excess Earnings	12	13	41 years
Other Regulatory Liabilities Being Paid	1	4	various
Regulatory Liabilities Currently Not Paying a Return			
Excess Asset Retirement Obligations for Nuclear Decommissioning Liability	436	377	(b)
Deferred Investment Tax Credits	136	144	50 years
Over-recovery of Transition Charges	57	41	15 years
Unrealized Gain on Forward Commitments	46	41	5 years
Spent Nuclear Fuel Liability	43	43	(b)
Peak Demand Reduction/Energy Efficiency	31	40	2 years
Deferred State Income Tax Coal Credits	29	29	10 years
Other Regulatory Liabilities Being Paid	27	22	various
Total Regulatory Liabilities Being Paid	3,435	3,129	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 3,544	$ 3,195	

(a) Relieved as removal costs are incurred.
(b) Relieved when plant is decommissioned.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on our financial statements.

COMMITMENTS

Construction and Commitments

The AEP System has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, we contractually commit to third-party construction vendors for certain material purchases and other construction services. We forecast approximately $3.6 billion of construction expenditures, excluding equity AFUDC and capitalized interest, for 2013. The subsidiaries purchase fuel, materials, supplies, services and property, plant and equipment under contract as part of their normal course of business. Certain supply contracts contain penalty provisions for early termination.

The following table summarizes our actual contractual commitments as of December 31, 2012:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 2,642	$ 3,928	$ 2,854	$ 2,908	$ 12,332
Energy and Capacity Purchase Contracts (b)	177	359	368	2,494	3,398
Construction Contracts for Capital Assets (c)	187	-	-	-	187
Total	$ 3,006	$ 4,287	$ 3,222	$ 5,402	$ 15,917

(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 we have signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

GUARANTEES

We record liabilities for guarantees 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

We enter into standby letters of credit with third parties. As Parent, we issue all of these letters of credit in our ordinary course of business on behalf of our subsidiaries. These letters of credit cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

We have two credit facilities totaling $3.25 billion, under which we may issue up to $1.35 billion as letters of credit. As of December 31, 2012, the maximum future payments for letters of credit issued under the credit facilities were $131 million with maturities ranging from January 2013 to April 2014. In February 2013, we increased and extended the $1.5 billion credit facility due in June 2015 to $1.75 billion due in June 2016, extended the $1.75 billion credit facility due in July 2016 to July 2017 and issued a $1 billion interim credit facility due in May 2015 to fund certain OPCo maturities.

We have $402 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $407 million. The letters of credit have maturities ranging from March 2013 to July 2014. In February 2013, we extended certain bilateral letters of credit due in March 2013 to July 2014 and March 2015.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $115 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study completed in 2010, we estimate the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately $58 million. As of December 31, 2012, SWEPCo has collected approximately $59 million through a rider for final mine closure and reclamation costs, of which $18 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $41 million is recorded in Asset Retirement Obligations on the balance sheets.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs to customers through its fuel clause.

Indemnifications and Other Guarantees

Contracts

We enter into several 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, our exposure generally does not exceed the sale price. The status of certain sale agreements is discussed in the "Dispositions" section of Note 6. As of December 31, 2012, there were no material liabilities recorded for any indemnifications.

Lease Obligations

We lease certain equipment under master lease agreements. See "Master Lease Agreements" and "Railcar Lease" sections of Note 12 for disclosure of lease residual value guarantees.

ENVIRONMENTAL CONTINGENCIES

Carbon Dioxide Public Nuisance Claims

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011. Plaintiffs refiled their complaint in federal district court. The court ordered all defendants to respond to the refiled complaints in October 2011. In March 2012, the court granted the defendants' motion for dismissal on several grounds, including the doctrine of collateral estoppel and the applicable statute of limitations. Plaintiffs appealed the decision to the Fifth Circuit Court of Appeals. We will continue to defend against the claims. We are 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. In September 2012, the Ninth Circuit Court of Appeals affirmed the trial court's decision, holding that the CAA displaced Kivalina's claims for damages. Plaintiffs' petition for rehearing by the full court was denied in November 2012, but the plaintiffs could seek further review in the U.S. Supreme Court. We believe the action is without merit and will continue to defend against the claims. We are 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, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. We currently incur 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. As of December 31, 2012, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for five sites for which alleged liability is unresolved. There are eight additional sites for which our subsidiaries have received information requests which could lead to PRP designation. Our subsidiaries have also been named potentially liable at three sites under state law including the I&M site discussed in the next paragraph. In those instances where we have been named a PRP or defendant, our disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ. I&M's reserve is approximately $10 million. As the remediation work is completed, I&M's cost may change as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation required by the MDEQ. We cannot predict the amount of additional cost, if any.

We evaluate the potential liability for each Superfund site separately, but several general statements can be made about our 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, our estimates do not anticipate material cleanup costs for any of our identified Superfund sites, except the I&M 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). We have a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generating units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the liability could be substantial.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The most recent decommissioning cost study was performed in 2012. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste ranges from $1.3 billion to $1.7 billion in 2012 nondiscounted dollars. The wide range in estimated costs is caused by variables in assumptions. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were $14 million, $14 million and $14 million for the years ended December 31, 2012, 2011 and 2010, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2012 and 2011, the total decommissioning trust fund balance was $1.4 billion and $1.3 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including interest, unrealized gains and losses and expenses of the trust funds) increase or decrease the recorded liability.

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

SNF Disposal

The Federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWh for fuel consumed after April 6, 1983 at the Cook Plant is being collected from customers and remitted to the U.S. Treasury. As of December 31, 2012 and 2011, 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 $308 million, respectively, to pay the fee are recorded as part of Spent Nuclear Fuel and Decommissioning Trusts. 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 $20 million and $14 million in 2012 and 2011, respectively, 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 costs for dry cask storage. As of December 31, 2012, I&M has deferred $32 million in Prepayments and Other Current Assets and $13 million in Deferred Charges and Other Noncurrent Assets on the balance sheet of dry cask storage and related operation and maintenance costs for recovery under this agreement.

See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 10 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 $40 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, it could reduce future net income and cash flows and impact financial condition.

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. 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. In February 2013, we signed an agreement and received payment from NEIL to settle the remaining insurance claims. The settlement did not have a material impact on net income, cash flows or financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

We maintain insurance coverage normal and customary for an integrated electric utility, subject to various deductibles. Our insurance includes coverage for all risks of physical loss or damage to our 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. Our insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of retentions absorbed by us. Coverage is generally provided by a combination of our 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 nuclear exposures and related insurance.

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

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against numerous energy companies, including AEP, alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were also filed in California and in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP (or a subsidiary) is among the companies named as defendants in some of these cases. We settled, received summary judgment or were dismissed from all of these cases. The plaintiffs appealed the dismissal of several cases involving AEP companies in Nevada to the Ninth Circuit Court of Appeals. Oral argument was held in October 2012. We will continue to defend the cases on appeal. We believe the provision we have is adequate. We believe the remaining exposure is immaterial.

6. ACQUISITIONS, DISPOSITIONS AND IMPAIRMENTS

ACQUISITIONS

2012

BlueStar Energy (Generation and Marketing segment)

In March 2012, we completed the acquisition of BlueStar Energy Holdings, Inc. (BlueStar) and its independent retail electric supplier BlueStar Energy Solutions for $70 million. This transaction also included goodwill of $15 million, intangible assets associated with sales contracts and customer accounts of $58 million and liabilities associated with supply contracts of $25 million. BlueStar has been in operation since 2002. Beginning in June 2012, BlueStar began doing business as AEP Energy. AEP Energy provides electric supply for retail customers in Ohio, Illinois and other deregulated electricity markets and also provides energy solutions throughout the United States, including demand response and energy efficiency services.

2010

Valley Electric Membership Corporation (Utility Operations segment)

In October 2010, SWEPCo purchased certain transmission and distribution assets of Valley Electric Membership Corporation (VEMCO) for approximately $102 million and began serving VEMCO's 30,000 customers in Louisiana.

Other Matters

Enron Bankruptcy

In February 2011, we reached a $425 million settlement covering all claims with BOA and Enron related to our purchase of Houston Pipeline Company (HPL) from Enron in 2001. As part of the settlement, we received title to the 55 billion cubic feet of natural gas in the Bammel storage facility and recorded this asset at fair value. Under the HPL sales agreement, we have a service obligation to the buyer for the right to use the cushion gas through May 2031. We recognized the obligation as a liability and will amortize it over the life of the agreement.

The settlement resulted in a pretax gain of $51 million and a net loss after tax of $22 million primarily due to an unrealized capital loss valuation allowance of $56 million.

DISPOSITIONS

2010

Texas Transmission Facilities (Utility Operations segment)

In 2010, TCC and TNC sold $66 million and $73 million, respectively, of transmission facilities to ETT. There were no gains or losses recorded on these sale transactions.

Intercontinental Exchange, Inc. (ICE) (All Other)

In April 2010, we sold our remaining 138,000 shares of ICE and recognized a $16 million gain. We recorded the gain in Interest and Investment Income on the statement of income for the year ended December 31, 2010.

IMPAIRMENTS

2012

Beckjord Plant Unit 6, Conesville Plant Unit 3, Kammer Plant Units 1-3, Muskingum River Plant Units 1-4, Sporn Plant Units 2 and 4 and Picway Plant Unit 5 (Utility Operations segment)

In October 2012, we filed applications with the FERC proposing to terminate the Interconnection Agreement and seeking to complete the corporate separation of OPCo's generation assets. Based on the intention to terminate the Interconnection Agreement and the FERC filing, we performed an evaluation of the recoverability of generation assets. As a result, in November 2012, we, using generating unit specific estimated future cash flows, concluded that OPCo had a material impairment of certain generation assets. Under a market-based value approach, using level 3 unobservable inputs, we determined that the fair value of these generating units was zero based on the lack of installed environmental control equipment and the nature and condition of these generating units. In the fourth quarter of 2012, OPCo recorded a pretax impairment of $287 million in Asset Impairments and Other Related Charges on the statement of income related to Beckjord Plant Unit 6, Conesville Plant Unit 3, Kammer Plant Units 1-3, Muskingum River Plant Units 1-4, Sporn Plant Units 2 and 4 and Picway Plant Unit 5 generating units which includes $13 million of related material and supplies inventory.

Turk Plant (Utility Operations segment)

In 2012, SWEPCo recorded a pretax write-off of $13 million in Asset Impairments and Other Related Charges on the statement of income related to unrecoverable construction costs subject to the Texas capital costs cap portion of the Turk Plant.

2011

Turk Plant (Utility Operations segment)

In the fourth quarter of 2011, SWEPCo recorded a pretax write-off of $49 million in Asset Impairments and Other Related Charges on the statement of income related to the Texas jurisdictional portion of the Turk Plant as a result of the November 2011 Texas Court of Appeals decision upholding the Texas capital cost cap.

Muskingum River Plant Unit 5 FGD Project (MR5) (Utility Operations segment)

In September 2011, subsequent to the stipulation agreement filed with the PUCO, we determined that OPCo was not likely to complete the previously suspended MR5 project and that the project's preliminary engineering costs were no longer probable of being recovered. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $42 million in Asset Impairments and Other Related Charges on the statement of income.

Sporn Plant Unit 5 (Utility Operations segment)

In the third quarter of 2011, we decided to no longer offer the output of Sporn Unit 5 into the PJM market. Sporn Unit 5 is not expected to operate in the future, resulting in the removal of Sporn Unit 5 from the Interconnection Agreement. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $48 million in Asset Impairments and Other Related Charges on the statement of income.

7. BENEFIT PLANS

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

We sponsor a qualified pension plan and two unfunded nonqualified pension plans. Substantially all of our employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. We sponsor OPEB plans to provide health and life insurance benefits for retired employees.

We recognize the funded status associated with our defined benefit pension and OPEB plans in the balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. We record a regulatory asset instead of other comprehensive income for qualifying benefit costs of our 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 our benefit obligations are shown in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2012**	**2011**	**2012**	**2011**
Discount Rate	3.95 %	4.55 %	3.95 %	4.75 %
Rate of Compensation Increase	4.95 % (a)	4.85 % (a)	NA	NA

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

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

For 2012, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 11.5% per year, with an average increase of 4.95%.

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans			Other Postretirement Benefit Plans		
	2012	**2011**	**2010**	**2012**	**2011**	**2010**
Discount Rate	4.55 %	5.05 %	5.60 %	4.75 %	5.25 %	5.85 %
Expected Return on Plan Assets	7.25 %	7.75 %	8.00 %	7.25 %	7.50 %	8.00 %
Rate of Compensation Increase	4.85 %	4.85 %	4.60 %	NA	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	2012	2011
Initial	7.00 %	7.50 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2020	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 millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 24	$ (19)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	118	(89)

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. We monitor the plans to control security diversification and ensure compliance with our investment policy. As of December 31, 2012, 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, 2012 and 2011

The following tables provide 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	
	2012	2011	2012	2011
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1	$ 4,991	$ 4,807	$ 2,227	$ 2,125
Service Cost	76	72	47	42
Interest Cost	223	237	103	109
Actuarial Loss	299	169	148	253
Plan Amendment Prior Service Credit	-	-	(570)	(196)
Curtailment and Settlements	(1)	-	-	1
Benefit Payments	(383)	(294)	(151)	(150)
Participant Contributions	-	-	35	34
Medicare Subsidy	-	-	10	9
Benefit Obligation as of December 31	$ 5,205	$ 4,991	$ 1,849	$ 2,227
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1	$ 4,303	$ 3,858	$ 1,410	$ 1,461
Actual Gain (Loss) on Plan Assets	560	282	178	(14)
Company Contributions	216	457	96	79
Participant Contributions	-	-	35	34
Benefit Payments	(383)	(294)	(151)	(150)
Fair Value of Plan Assets as of December 31	$ 4,696	$ 4,303	$ 1,568	$ 1,410
Underfunded Status as of December 31	$ (509)	$ (688)	$ (281)	$ (817)

Benefit Amounts Recognized on the Balance Sheets as of December 31, 2012 and 2011

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2012	2011	2012	2011
	(in millions)			
Other Current Liabilities - Accrued Short-term Benefit Liability	$ (7)	$ (8)	$ (4)	$ (4)
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	(502)	(680)	(277)	(813)
Underfunded Status	$ (509)	$ (688)	$ (281)	$ (817)

Amounts Included in AOCI and Regulatory Assets as of December 31, 2012 and 2011

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2012	2011	2012	2011
Components	(in millions)			
Net Actuarial Loss	$ 2,111	$ 2,208	$ 989	$ 979
Prior Service Cost (Credit)	11	10	(762)	(210)
Transition Obligation	-	-	-	1
Recorded as				
Regulatory Assets	$ 1,774	$ 1,818	$ 108	$ 479
Deferred Income Taxes	122	140	42	102
Net of Tax AOCI	226	260	77	189

Components of the change in amounts included in AOCI and Regulatory Assets during the years ended December 31, 2012 and 2011 are as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2012	2011	2012	2011
Components	(in millions)			
Actuarial Loss During the Year	$ 58	$ 201	$ 67	$ 370
Prior Service Credit	-	-	(570)	(191)
Amortization of Actuarial Loss	(155)	(122)	(57)	(29)
Amortization of Prior Service Credit (Cost)	1	(1)	18	1
Amortization of Transition Obligation	-	-	(1)	(2)
Change for the Year	$ (96)	$ 78	$ (543)	$ 149

Pension and Other Postretirement Plans' Assets

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

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 1,308	$ -	$ -	$ -	$ 1,308	27.9 %
International	497	-	-	-	497	10.5 %
Real Estate Investment Trusts	91	-	-	-	91	1.9 %
Common Collective Trust - International	-	4	-	-	4	0.1 %
Subtotal - Equities	1,896	4	-	-	1,900	40.4 %
Fixed Income:						
Common Collective Trust - Debt	-	32	-	-	32	0.7 %
United States Government and Agency Securities	-	715	-	-	715	15.2 %
Corporate Debt	-	1,235	-	-	1,235	26.3 %
Foreign Debt	-	199	-	-	199	4.2 %
State and Local Government	-	44	-	-	44	0.9 %
Other - Asset Backed	-	36	-	-	36	0.8 %
Subtotal - Fixed Income	-	2,261	-	-	2,261	48.1 %
Real Estate	-	-	220	-	220	4.7 %
Alternative Investments	-	-	195	-	195	4.2 %
Securities Lending	-	80	-	-	80	1.7 %
Securities Lending Collateral (a)	-	-	-	(91)	(91)	(1.9)%
Cash and Cash Equivalents	-	126	-	-	126	2.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	5	5	0.1 %
Total	$ 1,896	$ 2,471	$ 415	$ (86)	$ 4,696	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

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

	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in millions)		
Balance as of January 1, 2012	$ 6	$ 163	$ 161	$ 330
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	30	10	40
Relating to Assets Sold During the Period	(2)	-	4	2
Purchases and Sales	(4)	27	20	43
Transfers into Level 3	-	-	-	-
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2012	$ -	$ 220	$ 195	$ 415

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

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 422	$ -	$ -	$ -	$ 422	26.9 %
International	505	-	-	-	505	32.2 %
Subtotal - Equities	927	-	-	-	927	59.1 %
Fixed Income:						
Common Collective Trust - Debt	-	72	-	-	72	4.6 %
United States Government and Agency Securities	-	82	-	-	82	5.2 %
Corporate Debt	-	155	-	-	155	9.9 %
Foreign Debt	-	26	-	-	26	1.7 %
State and Local Government	-	7	-	-	7	0.5 %
Other - Asset Backed	-	10	-	-	10	0.6 %
Subtotal - Fixed Income	-	352	-	-	352	22.5 %
Trust Owned Life Insurance:						
International Equities	-	52	-	-	52	3.3 %
United States Bonds	-	163	-	-	163	10.3 %
Cash and Cash Equivalents	62	11	-	-	73	4.7 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	1	1	0.1 %
Total	$ 989	$ 578	$ -	$ 1	$ 1,568	100.0 %

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

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

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 1,455	$ -	$ -	$ -	$ 1,455	33.8 %
International	399	-	-	-	399	9.3 %
Real Estate Investment Trusts	104	-	-	-	104	2.4 %
Common Collective Trust - International	-	128	-	-	128	3.0 %
Subtotal - Equities	1,958	128	-	-	2,086	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	26	-	-	26	0.6 %
United States Government and Agency Securities	-	566	-	-	566	13.2 %
Corporate Debt	-	985	6	-	991	23.0 %
Foreign Debt	-	190	-	-	190	4.4 %
State and Local Government	-	48	-	-	48	1.1 %
Other - Asset Backed	-	26	-	-	26	0.6 %
Subtotal - Fixed Income	-	1,841	6	-	1,847	42.9 %
Real Estate	-	-	163	-	163	3.8 %
Alternative Investments	-	-	161	-	161	3.7 %
Securities Lending	-	215	-	-	215	5.0 %
Securities Lending Collateral (a)	-	-	-	(236)	(236)	(5.5)%
Cash and Cash Equivalents	-	93	-	-	93	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(26)	(26)	(0.6)%
Total	$ 1,958	$ 2,277	$ 330	$ (262)	$ 4,303	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

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

	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in millions)		
Balance as of January 1, 2011	$ -	$ 83	$ 130	$ 213
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	22	9	31
Relating to Assets Sold During the Period	-	-	3	3
Purchases and Sales	-	58	19	77
Transfers into Level 3	6	-	-	6
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2011	$ 6	$ 163	$ 161	$ 330

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

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 348	$ -	$ -	$ -	$ 348	24.7 %
International	380	-	-	-	380	27.0 %
Common Collective Trust - Global	-	99	-	-	99	7.0 %
Subtotal - Equities	728	99	-	-	827	58.7 %
Fixed Income:						
Common Collective Trust - Debt	-	69	-	-	69	4.9 %
United States Government and Agency Securities	-	81	-	-	81	5.7 %
Corporate Debt	-	152	-	-	152	10.8 %
Foreign Debt	-	32	-	-	32	2.3 %
State and Local Government	-	9	-	-	9	0.6 %
Other - Asset Backed	-	2	-	-	2	0.1 %
Subtotal - Fixed Income	-	345	-	-	345	24.4 %
Trust Owned Life Insurance:						
International Equities	-	46	-	-	46	3.3 %
United States Bonds	-	158	-	-	158	11.2 %
Cash and Cash Equivalents	17	23	-	-	40	2.9 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	(6)	(6)	(0.5)%
Total	$ 745	$ 671	$ -	$ (6)	$ 1,410	100.0 %

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

Determination of Pension Expense

We base our determination of pension expense or income 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.

Accumulated Benefit Obligation	December 31, 2012	December 31, 2011
	(in millions)	
Qualified Pension Plan	$ 5,001	$ 4,808
Nonqualified Pension Plans	82	89
Total	$ 5,083	$ 4,897

For our underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets of these plans as of December 31, 2012 and 2011 were as follows:

	Underfunded Pension Plans December 31, 2012	Underfunded Pension Plans December 31, 2011
	(in millions)	
Projected Benefit Obligation	$ 5,205	$ 4,991
Accumulated Benefit Obligation	$ 5,083	$ 4,897
Fair Value of Plan Assets	4,696	4,303
Underfunded Accumulated Benefit Obligation	$ (387)	$ (594)

Estimated Future Benefit Payments and Contributions

We expect contributions and payments for the pension plans of $108 million and the OPEB plans of $4 million during 2013. For the pension plans, this amount includes the payment of unfunded nonqualified benefits plus contributions to the qualified trust fund of at least the minimum amount required by the Employee Retirement Income Security Act. For the qualified pension plan, we may also make additional discretionary contributions to maintain the funded status of the plan. For the OPEB plans, expected payments include the payment of unfunded benefits.

The table below reflects the total benefits expected to be paid from the plan or from our assets. The payments include the participants' contributions to the plan for their share of the cost. In November 2012, we announced changes to our retiree medical coverage. Effective for retirements after December 2012, our contribution to retiree medical coverage will be capped reducing our exposure to future medical cost inflation. Effective for employees hired after December 2013, we will not provide retiree medical coverage. In December 2011, we amended the prescription drug program for certain participants. The impact of the changes is reflected in the Benefit Plan Obligation table as plan amendments. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for pension benefits and OPEB are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2013	$ 340	$ 140	$ -
2014	349	146	-
2015	356	153	-
2016	359	162	-
2017	364	171	-
Years 2018 to 2022, in Total	1,844	990	2

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the plans for the years ended December 31, 2012, 2011 and 2010:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2012	2011	2010	2012	2011	2010
	(in millions)					
Service Cost	$ 76	$ 72	$ 111	$ 47	$ 42	$ 47
Interest Cost	223	237	253	103	109	113
Expected Return on Plan Assets	(319)	(314)	(312)	(101)	(109)	(105)
Curtailment	-	-	-	-	1	-
Amortization of Transition Obligation	-	-	-	1	2	27
Amortization of Prior Service Cost (Credit)	(1)	1	-	(18)	(1)	-
Amortization of Net Actuarial Loss	155	122	89	57	29	29
Net Periodic Benefit Cost	134	118	141	89	73	111
Capitalized Portion	(42)	(37)	(44)	(28)	(22)	(35)
Net Periodic Benefit Cost Recognized as Expense	$ 92	$ 81	$ 97	$ 61	$ 51	$ 76

Estimated amounts expected to be amortized to net periodic benefit costs (credits) and the impact on the balance sheet during 2013 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 176	$ 64
Prior Service Cost (Credit)	3	(69)
Total Estimated 2013 Amortization	$ 179	$ (5)
Expected to be Recorded as		
Regulatory Asset	$ 148	$ (7)
Deferred Income Taxes	11	1
Net of Tax AOCI	20	1
Total	$ 179	$ (5)

American Electric Power System Retirement Savings Plan

We sponsor the American Electric Power System Retirement Savings Plan, a defined contribution retirement savings plan for substantially all employees who are not members of the United Mine Workers of America (UMWA). It is a qualified plan offering participants an opportunity to contribute a portion of their pay with features under Section 401(k) of the Internal Revenue Code. 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 totaled $66 million in 2012, $64 million in 2011 and $61 million in 2010.

UMWA Benefits

We provide 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. The health and welfare benefits are administered by us and benefits are paid from our 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 any 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, 2012 and 2011, without utilization of extended amortization provisions. The Plan adopted a funding improvement plan in May 2012, as required under the PPA. Contributions in 2012, 2011 and 2010 were made under a collective bargaining agreement that is scheduled to expire December 31, 2013. We contributed immaterial amounts in 2012, 2011 and 2010 that represent less than 5% of the total contributions in the plan's latest annual report for the years ended June 30, 2012, 2011 and 2010. The contributions we made did not include a surcharge. There are no minimum contributions for future years.

8. BUSINESS SEGMENTS

Our primary business is the generation, transmission and distribution of electricity. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable segments and their related business activities are outlined below:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Transmission and distribution of electricity through assets owned and operated by our ten utility operating companies.

Transmission Operations

- Development, construction and operation of transmission facilities through investments in our wholly-owned transmission subsidiaries and transmission joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

AEP River Operations

- Commercial barging operations that transport coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers.

Generation and Marketing

- Nonregulated generation in ERCOT.
- Marketing, risk management and retail activities in ERCOT, PJM and MISO.

The remainder of our activities is presented as All Other. While not considered a reportable segment, All Other includes:

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations, which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts were financial derivatives which settled and expired in the fourth quarter of 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility, which ended in the fourth quarter of 2011.

The tables below present our reportable segment information for the years ended December 31, 2012, 2011 and 2010 and balance sheet information as of December 31, 2012 and 2011. These amounts include certain estimates and allocations where necessary.

			Nonutility Operations				
	Utility Operations	Transmission Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Year Ended December 31, 2012							
Revenues from:							
External Customers	$ 13,670	$ 7	$ 647	$ 599	$ 22	$ -	$ 14,945
Other Operating Segments	108	17	20	1	8	(154)	-
Total Revenues	$ 13,778	$ 24	$ 667	$ 600	$ 30	$ (154)	$ 14,945
Asset Impairments and Other Related Charges	$ 300	$ -	$ -	$ -	$ -	$ -	$ 300
Depreciation and Amortization	1,734	3	29	28	-	(12)(b)	1,782
Interest Income	7	-	-	-	20	(19)	8
Carrying Costs Income	53	-	-	-	-	-	53
Interest Expense	882	3	17	19	102	(35)(b)	988
Income Tax Expense	560	17	7	3	17	-	604
Net Income (Loss)	1,299	43	15	7	(102)	-	1,262
Gross Property Additions	2,625	392	31	71	-	-	3,119

			Nonutility Operations				
	Utility Operations	Transmission Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Year Ended December 31, 2011							
Revenues from:							
External Customers	$ 14,088	$ 3	$ 696	$ 305	$ 24	$ -	$ 15,116
Other Operating Segments	112	5	20	1	8	(146)	-
Total Revenues	$ 14,200	$ 8	$ 716	$ 306	$ 32	$ (146)	$ 15,116
Asset Impairments and Other Related Charges	$ 139	$ -	$ -	$ -	$ -	$ -	$ 139
Depreciation and Amortization	1,613	-	28	25	2	(13)(b)	1,655
Interest Income	29	-	-	(1)	17	(18)	27
Carrying Costs Income	393	-	-	-	-	-	393
Interest Expense	886	1	18	18	43	(33)(b)	933
Income Tax Expense (Credit)	722	2	24	(18)	88	-	818
Income (Loss) Before Extraordinary Item	$ 1,549	$ 30	$ 45	$ 14	$ (62)	$ -	$ 1,576
Extraordinary Item, Net of Tax	373	-	-	-	-	-	373
Net Income (Loss)	$ 1,922	$ 30	$ 45	$ 14	$ (62)	$ -	$ 1,949
Gross Property Additions	$ 2,405	$ 263	$ 18	$ 2	$ 214	$ -	$ 2,902

	Utility Operations	Transmission Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Year Ended December 31, 2010							
Revenues from:							
External Customers	$ 13,687	$ -	$ 566	$ 173	$ 1	$ -	$ 14,427
Other Operating Segments	105	1	22	-	14	(142)	-
Total Revenues	$ 13,792	$ 1	$ 588	$ 173	$ 15	$ (142)	$ 14,427
Asset Impairments and Other Related Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Depreciation and Amortization	1,598	-	24	30	2	(13)(b)	1,641
Interest Income	8	-	-	2	31	(20)	21
Carrying Costs Income	70	-	-	-	-	-	70
Interest Expense	942	-	14	20	58	(35)(b)	999
Income Tax Expense (Credit)	651	(1)	19	(20)	(6)	-	643
Net Income (Loss)	1,192	9	37	25	(45)	-	1,218
Gross Property Additions	2,440	35	23	1	1	-	2,500

	Utility Operations	Transmission Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
December 31, 2012							
Total Property, Plant and Equipment	$ 55,707	$ 748	$ 636	$ 621	$ 8	$ (266)	$ 57,454
Accumulated Depreciation and Amortization	18,344	4	161	246	7	(71)	18,691
Total Property, Plant and Equipment - Net	$ 37,363	$ 744	$ 475	$ 375	$ 1	$ (195)	$ 38,763
Total Assets	$ 51,477	$ 1,216	$ 670	$ 1,005	$ 17,191	$ (17,192) (c)	$ 54,367
Investments in Equity Method Investees	24	393	43	-	5	-	465

	Utility Operations	Transmission Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
December 31, 2011							
Total Property, Plant and Equipment	$ 54,396	$ 323	$ 608	$ 590	$ 11	$ (258)	$ 55,670
Accumulated Depreciation and Amortization	18,393	-	136	219	10	(59)	18,699
Total Property, Plant and Equipment - Net	$ 36,003	$ 323	$ 472	$ 371	$ 1	$ (199)	$ 36,971
Total Assets	$ 50,093	$ 594	$ 659	$ 868	$ 16,751	$ (16,742) (c)	$ 52,223
Investments in Equity Method Investees	24	256	17	-	2	-	299

(a) All Other includes:
- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations, which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts were financial derivatives which settled and expired in the fourth quarter of 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility, which ended in the fourth quarter of 2011.

(b) Includes eliminations due to an intercompany capital lease.
(c) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.

9. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

We are 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 us due to changes in the underlying market prices or rates. We manage these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

We enter 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 our energy business. We enter into interest rate derivative contracts in order to manage the interest rate exposure associated with our commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as they are related to energy risk management activities. We also engage 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 our established risk management policies as approved by the Finance Committee of our Board of Directors.

The following table represents the gross notional volume of our outstanding derivative contracts as of December 31, 2012 and 2011:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume December 31, 2012	Volume December 31, 2011	Unit of Measure
	(in millions)		
Commodity:			
Power	498	609	MWhs
Coal	10	21	Tons
Natural Gas	147	100	MMBtus
Heating Oil and Gasoline	6	6	Gallons
Interest Rate	$ 235	$ 226	USD
Interest Rate and Foreign Currency	$ 1,199	$ 907	USD

Fair Value Hedging Strategies

We enter 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 our exposure to interest rate risk by converting a portion of our 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

We enter into and designate 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. We monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. We do not hedge all commodity price risk.

Our vehicle fleet and barge operations are exposed to gasoline and diesel fuel price volatility. We enter into financial heating oil and gasoline derivative contracts in order to mitigate price risk of our future fuel purchases. For disclosure purposes, these contracts are included with other hedging activities as "Commodity." We do not hedge all fuel price risk.

We enter into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our floating-rate debt to a fixed rate. We also enter into interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. Our 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. We do not hedge all interest rate exposure.

At times, we are exposed to foreign currency exchange rate risks primarily when we purchase certain fixed assets from foreign suppliers. In accordance with our risk management policy, we 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. We do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON OUR FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of our derivative instruments, we also apply 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 our 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 our risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," we reflect the fair values of our derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, we are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2012 and 2011 balance sheets, we netted $7 million and $26 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $50 million and $133 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of our derivative activity on the balance sheets as of December 31, 2012 and 2011:

Fair Value of Derivative Instruments
December 31, 2012

	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
			(in millions)			
Current Risk Management Assets	$ 589	$ 32	$ 3	$ 624	$ (433)	$ 191
Long-term Risk Management Assets	528	5	1	534	(166)	368
Total Assets	1,117	37	4	1,158	(599)	559
Current Risk Management Liabilities	546	43	35	624	(469)	155
Long-term Risk Management Liabilities	383	6	6	395	(181)	214
Total Liabilities	929	49	41	1,019	(650)	369
Total MTM Derivative Contract Net Assets (Liabilities)	$ 188	$ (12)	$ (37)	$ 139	$ 51	$ 190

Fair Value of Derivative Instruments
December 31, 2011

	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
			(in millions)			
Current Risk Management Assets	$ 852	$ 24	$ -	$ 876	$ (683)	$ 193
Long-term Risk Management Assets	641	15	-	656	(253)	403
Total Assets	1,493	39	-	1,532	(936)	596
Current Risk Management Liabilities	847	29	20	896	(746)	150
Long-term Risk Management Liabilities	483	15	22	520	(325)	195
Total Liabilities	1,330	44	42	1,416	(1,071)	345
Total MTM Derivative Contract Net Assets (Liabilities)	$ 163	$ (5)	$ (42)	$ 116	$ 135	$ 251

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

The table below presents our activity of derivative risk management contracts for the years ended December 31, 2012, 2011 and 2010:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2012	2011	2010
		(in millions)	
Utility Operations Revenues	$ 21	$ 46	$ 85
Other Revenues	39	20	9
Regulatory Assets (a)	(43)	(22)	(9)
Regulatory Liabilities (a)	8	(3)	38
Total Gain (Loss) on Risk Management Contracts	$ 25	$ 41	$ 123

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

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.

Our 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, we designate 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.

We record 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 Expense on the statements of income. During 2012, the fair value changes for both our hedging instruments and hedged long-term debt were immaterial. During 2011 and 2010, we recognized gains of $3 million and $6 million, respectively, on our hedging instruments and offsetting losses of $6 million and $6 million, respectively, on our long-term debt. For 2012, 2011 and 2010, hedge ineffectiveness was immaterial.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects Net Income. We recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale 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 2012, 2011 and 2010, we designated power, coal and natural gas derivatives as cash flow hedges.

We reclassify gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the statements of income. During 2012, 2011 and 2010, we designated heating oil and gasoline derivatives as cash flow hedges.

We reclassify gains and losses on interest rate derivative hedges related to our debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During 2012, 2011 and 2010, we designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to our foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Depreciation and Amortization expense on the statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During 2012, 2011 and 2010, we designated foreign currency derivatives as cash flow hedges.

During 2012, 2011 and 2010, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets and the reasons for changes in cash flow hedges for the years ended December 31, 2012, 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, 2012

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2011	$ (3)	$ (20)	$ (23)
Changes in Fair Value Recognized in AOCI	(15)	(14)	(29)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	-	-	-
Other Revenues	(5)	-	(5)
Purchased Electricity for Resale	13	-	13
Other Operation Expense	-	-	-
Maintenance Expense	-	-	-
Interest Expense	-	4	4
Property, Plant and Equipment	-	-	-
Regulatory Assets (a)	2	-	2
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2012	$ (8)	$ (30)	$ (38)

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

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2010	$ 7	$ 4	$ 11
Changes in Fair Value Recognized in AOCI	(5)	(28)	(33)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	3	-	3
Other Revenues	(5)	-	(5)
Purchased Electricity for Resale	(2)	-	(2)
Other Operation Expense	(1)	-	(1)
Maintenance Expense	(1)	-	(1)
Interest Expense	-	4	4
Property, Plant and Equipment	(1)	-	(1)
Regulatory Assets (a)	2	-	2
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2011	$ (3)	$ (20)	$ (23)

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

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2009	$ (2)	$ (13)	$ (15)
Changes in Fair Value Recognized in AOCI	9	13	22
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	-	-	-
Other Revenues	(7)	-	(7)
Purchased Electricity for Resale	4	-	4
Other Operation Expense	-	-	-
Maintenance Expense	-	-	-
Interest Expense	-	4	4
Property, Plant and Equipment	-	-	-
Regulatory Assets (a)	3	-	3
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2010	$ 7	$ 4	$ 11

(a) Represents realized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets as of December 31, 2012 and 2011 were:

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

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 24	$ -	$ 24
Hedging Liabilities (a)	36	37	73
AOCI Gain (Loss) Net of Tax	(8)	(30)	(38)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(8)	(4)	(12)

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

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 20	$ -	$ 20
Hedging Liabilities (a)	25	42	67
AOCI Gain (Loss) Net of Tax	(3)	(20)	(23)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(3)	(2)	(5)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the balance sheets.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of December 31, 2012, the maximum length of time that we are hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") our exposure to variability in future cash flows related to forecasted transactions is 33 months.

Credit Risk

We limit credit risk in our 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. We use 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.

We use 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 our established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with our 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 our competitive retail auction loads, we are obligated to post an additional amount of collateral if our credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and our total exposure. On an ongoing basis, our risk management organization assesses the appropriateness of these collateral triggering items in contracts. AEP and its subsidiaries have not experienced a downgrade below investment grade. The following table represents: (a) our fair value of such derivative contracts, (b) the amount of collateral we would have been required to post for all derivative and non-derivative contracts if our credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of December 31, 2012 and 2011:

	December 31, 2012	December 31, 2011
	(in millions)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 7	$ 32
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post	32	39
Amount Attributable to RTO and ISO Activities	31	38

In addition, a majority of our 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, our risk management organization assesses the appropriateness of these cross-default provisions in our contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral we have posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering our contractual netting arrangements as of December 31, 2012 and 2011:

	December 31, 2012	December 31, 2011
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 469	$ 515
Amount of Cash Collateral Posted	8	56
Additional Settlement Liability if Cross Default Provision is Triggered	328	291

10. <u>FAIR VALUE MEASUREMENTS</u>

Fair Value Measurements of Long-term Debt

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

The book values and fair values of Long-term Debt as of December 31, 2012 and 2011 are summarized in the following table:

	December 31, 2012		December 31, 2011	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 17,757	$ 20,907	$ 16,516	$ 19,259

Fair Value Measurements of Other Temporary Investments

Other Temporary Investments include funds held by trustees primarily for the payment of securitization bonds, marketable securities that we intend to hold for less than one year and investments by our protected cell of EIS. See "Other Temporary Investments" section of Note 1.

The following is a summary of Other Temporary Investments:

	December 31, 2012			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Estimated Fair Value**
		(in millions)		
Restricted Cash (a)	$ 241	$ -	$ -	$ 241
Fixed Income Securities:				
Mutual Funds	65	2	-	67
Equity Securities - Mutual Funds	10	6	-	16
Total Other Temporary Investments	$ 316	$ 8	$ -	$ 324

	December 31, 2011			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Estimated Fair Value**
		(in millions)		
Restricted Cash (a)	$ 216	$ -	$ -	$ 216
Fixed Income Securities:				
Mutual Funds	64	-	-	64
Equity Securities - Mutual Funds	11	3	-	14
Total Other Temporary Investments	$ 291	$ 3	$ -	$ 294

(a) Primarily represents amounts held for the payment of debt.

The following table provides the activity for our debt and equity securities within Other Temporary Investments for the years ended December 31, 2012, 2011 and 2010:

	Years Ended December 31,		
	2012	**2011**	**2010**
		(in millions)	
Proceeds from Investment Sales	$ -	$ 268	$ 455
Purchases of Investments	2	154	503
Gross Realized Gains on Investment Sales	-	4	16
Gross Realized Losses on Investment Sales	-	-	-

As of December 31, 2012 and 2011, we had no Other Temporary Investments with an unrealized loss position. As of December 31, 2012, fixed income securities are primarily debt based mutual funds with short and intermediate maturities. Mutual funds may be sold and do not contain maturity dates.

The following table provides details of Other Temporary Investments included in Accumulated Other Comprehensive Income (Loss) on the balance sheets and the reasons for changes for the years ended December 31, 2012 and 2011. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Other Temporary Investments
Years Ended December 31, 2012 and 2011

	(in millions)	
Balance in AOCI as of December 31, 2010	$	4
Changes in Fair Value Recognized in AOCI		1
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income:		
Interest Income		(3)
Balance in AOCI as of December 31, 2011		2
Changes in Fair Value Recognized in AOCI		2
Balance in AOCI as of December 31, 2012	$	4

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

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

The following is a summary of nuclear trust fund investments as of December 31, 2012 and December 31, 2011:

	December 31, 2012			December 31, 2011		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 17	$ -	$ -	$ 18	$ -	$ -
Fixed Income Securities:						
United States Government	648	58	(1)	544	61	(1)
Corporate Debt	35	5	(1)	54	5	(2)
State and Local Government	270	1	(1)	330	-	(2)
Subtotal Fixed Income Securities	953	64	(3)	928	66	(5)
Equity Securities - Domestic	736	285	(77)	646	215	(80)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,706	$ 349	$ (80)	$ 1,592	$ 281	$ (85)

The following table provides the securities activity within the decommissioning and SNF trusts for the years ended December 31, 2012, 2011 and 2010:

	Years Ended December 31, 2012	2011	2010
	(in millions)		
Proceeds from Investment Sales	$ 988	$ 1,111	$ 1,362
Purchases of Investments	1,045	1,167	1,415
Gross Realized Gains on Investment Sales	25	33	12
Gross Realized Losses on Investment Sales	9	22	2

The adjusted cost of debt securities was $889 million and $862 million as of December 31, 2012 and 2011, respectively. The adjusted cost of equity securities was $451 million and $431 million as of December 31, 2012 and 2011, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2012 was as follows:

	Fair Value of Debt Securities (in millions)
Within 1 year	$ 81
1 year – 5 years	373
5 years – 10 years	266
After 10 years	233
Total	$ 953

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, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2012 and 2011. 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. Our 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 our valuation techniques.

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 6	$ 1	$ -	$ 272	$ 279
Other Temporary Investments					
Restricted Cash (a)	227	5	-	9	241
Fixed Income Securities:					
Mutual Funds	67	-	-	-	67
Equity Securities - Mutual Funds (b)	16	-	-	-	16
Total Other Temporary Investments	310	5	-	9	324
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	47	938	131	(599)	517
Cash Flow Hedges:					
Commodity Hedges (c)	8	28	-	(12)	24
Fair Value Hedges	-	2	-	2	4
De-designated Risk Management Contracts (e)	-	-	-	14	14
Total Risk Management Assets	55	968	131	(595)	559
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	7	-	-	10	17
Fixed Income Securities:					
United States Government	-	648	-	-	648
Corporate Debt	-	35	-	-	35
State and Local Government	-	270	-	-	270
Subtotal Fixed Income Securities	-	953	-	-	953
Equity Securities - Domestic (b)	736	-	-	-	736
Total Spent Nuclear Fuel and Decommissioning Trusts	743	953	-	10	1,706
Total Assets	$ 1,114	$ 1,927	$ 131	$ (304)	$ 2,868
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 45	$ 838	$ 45	$ (636)	$ 292
Cash Flow Hedges:					
Commodity Hedges (c)	-	48	-	(12)	36
Interest Rate/Foreign Currency Hedges	-	37	-	-	37
Fair Value Hedges	-	2	-	2	4
Total Risk Management Liabilities	$ 45	$ 925	$ 45	$ (646)	$ 369

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 6	$ -	$ -	$ 215	$ 221
Other Temporary Investments					
Restricted Cash (a)	191	-	-	25	216
Fixed Income Securities:					
Mutual Funds	64	-	-	-	64
Equity Securities - Mutual Funds (b)	14	-	-	-	14
Total Other Temporary Investments	269	-	-	25	294
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	47	1,299	147	(945)	548
Cash Flow Hedges:					
Commodity Hedges (c)	15	23	-	(18)	20
De-designated Risk Management Contracts (e)	-	-	-	28	28
Total Risk Management Assets	62	1,322	147	(935)	596
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	-	5	-	13	18
Fixed Income Securities:					
United States Government	-	544	-	-	544
Corporate Debt	-	54	-	-	54
State and Local Government	-	330	-	-	330
Subtotal Fixed Income Securities	-	928	-	-	928
Equity Securities - Domestic (b)	646	-	-	-	646
Total Spent Nuclear Fuel and Decommissioning Trusts	646	933	-	13	1,592
Total Assets	$ 983	$ 2,255	$ 147	$ (682)	$ 2,703
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ 43	$ 1,209	$ 78	$ (1,052)	$ 278
Cash Flow Hedges:					
Commodity Hedges (c)	-	43	-	(18)	25
Interest Rate/Foreign Currency Hedges	-	42	-	-	42
Total Risk Management Liabilities	$ 43	$ 1,294	$ 78	$ (1,070)	$ 345

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.

(b) Amounts represent publicly traded equity securities and equity-based mutual funds.

(c) 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."

(d) The December 31, 2012 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $9 million in 2013, $(3) million in periods 2014-2016 and ($4) million in periods 2017-2018; Level 2 matures $16 million in 2013, $61 million in periods 2014-2016, $16 million in periods 2017-2018 and $7 million in periods 2019-2030; Level 3 matures $18 million in 2013, $31 million in periods 2014-2016, $13 million in periods 2017-2018 and $24 million in periods 2019-2030. Risk management commodity contracts are substantially comprised of power contracts.

(e) 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.

(f) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.

(g) The December 31, 2011 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $3 million in 2012, $7 million in periods 2013-2015 and ($6) million in periods 2016-2018; Level 2 matures $21 million in 2012, $50 million in periods 2013-2015, $11 million in periods 2016-2017 and $8 million in periods 2018-2030; Level 3 matures ($19) million in 2012, $44 million in periods 2013-2015, $18 million in periods 2016-2017 and $26 million in periods 2018-2030. Risk management commodity contracts are substantially comprised of power contracts.

There have been no transfers between Level 1 and Level 2 during the years ended December 31, 2012, 2011 and 2010.

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

Year Ended December 31, 2012		Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2011	$	69
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		(15)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		29
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-
Purchases, Issuances and Settlements (c)		32
Transfers into Level 3 (d) (e)		1
Transfers out of Level 3 (e) (f)		(35)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		5
Balance as of December 31, 2012	$	86

Year Ended December 31, 2011		Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2010	$	85
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		(10)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		9
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-
Purchases, Issuances and Settlements (c)		(3)
Transfers into Level 3 (d) (e)		13
Transfers out of Level 3 (e) (f)		(12)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		(13)
Balance as of December 31, 2011	$	69

Year Ended December 31, 2010		Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2009	$	62
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		5
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		63
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-
Purchases, Issuances and Settlements (c)		(25)
Transfers into Level 3 (d) (e)		18
Transfers out of Level 3 (e) (f)		(53)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		15
Balance as of December 31, 2010	$	85

(a) Included in revenues on the statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Represents existing assets or liabilities that were previously categorized as Level 3.
(g) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

The following table quantifies the significant unobservable inputs used in developing the fair value of our Level 3 positions as of December 31, 2012:

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range High
	(in millions)					
Energy Contracts	$ 124	$ 38	Discounted Cash Flow	Forward Market Price (a)	$ 9.40	$ 111.97
				Counterparty Credit Risk (b)	397	
FTRs	7	7	Discounted Cash Flow	Forward Market Price (a)	(3.21)	14.79
Total	$ 131	$ 45				

(a) Represents market prices in dollars per MWh.
(b) Represents average price of credit default swaps used to calculate counterparty credit risk, reported in basis points.

11. INCOME TAXES

The details of our consolidated income taxes before extraordinary item as reported are as follows:

	Years Ended December 31, 2012	2011	2010
		(in millions)	
Federal:			
Current	$ (52)	$ 20	$ (134)
Deferred	698	786	760
Total Federal	646	806	626
State and Local:			
Current	35	37	(20)
Deferred	(77)	(25)	38
Total State and Local	(42)	12	18
International:			
Current	-	-	(1)
Deferred	-	-	-
Total International	-	-	(1)
Income Tax Expense	$ 604	$ 818	$ 643

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

	Years Ended December 31,		
	2012	2011	2010
		(in millions)	
Net Income	$ 1,262	$ 1,949	$ 1,218
Extraordinary Item, Net of Tax of $(112) million in 2011	-	(373)	-
Income Before Extraordinary Item	1,262	1,576	1,218
Income Tax Expense	604	818	643
Pretax Income	$ 1,866	$ 2,394	$ 1,861
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 653	$ 838	$ 651
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	39	41	47
Investment Tax Credits, Net	(14)	(15)	(16)
Energy Production Credits	-	(18)	(20)
State and Local Income Taxes, Net	(33)	(22)	11
Removal Costs	(18)	(20)	(19)
AFUDC	(39)	(42)	(33)
Medicare Subsidy	3	1	12
Valuation Allowance	6	86	-
Tax Reserve Adjustments	17	2	(16)
Other	(10)	(33)	26
Income Tax Expense	$ 604	$ 818	$ 643
Effective Income Tax Rate	32.4 %	34.2 %	34.6 %

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

	December 31,	
	2012	2011
	(in millions)	
Deferred Tax Assets	$ 2,900	$ 2,855
Deferred Tax Liabilities	(12,098)	(11,185)
Net Deferred Tax Liabilities	$ (9,198)	$ (8,330)
Property Related Temporary Differences	$ (6,752)	$ (5,963)
Amounts Due from Customers for Future Federal Income Taxes	(289)	(259)
Deferred State Income Taxes	(683)	(668)
Securitized Transition Assets	(780)	(621)
Regulatory Assets	(781)	(1,208)
Postretirement Benefits	266	424
Accrued Pensions	104	149
Deferred Income Taxes on Other Comprehensive Loss	184	254
Accrued Nuclear Decommissioning	(475)	(436)
Net Operating Loss Carryforward	194	125
Tax Credit Carryforward	104	182
Valuation Allowance	(92)	(86)
All Other, Net	(198)	(223)
Net Deferred Tax Liabilities	$ (9,198)	$ (8,330)

AEP System Tax Allocation Agreement

We, along with our subsidiaries, file a consolidated federal income tax return. 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 our 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

We are no longer subject to U.S. federal examination for years before 2009. We 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 materially impact 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, we accrue interest on these uncertain tax positions. We are not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

We, along with our subsidiaries, file income tax returns in various state, local and foreign jurisdictions. These taxing authorities routinely examine our tax returns and we are currently under examination in several state and local jurisdictions. We believe that we have filed tax returns with positions that may be challenged by these tax authorities. We believe that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and the ultimate resolution of these audits will not materially impact net income. With few exceptions, we are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2008. In March 2012, we settled all outstanding franchise tax issues with the state of Ohio for the years 2000 through 2009. The settlements did not materially impact net income, cash flows or financial condition.

Net Income Tax Operating Loss Carryforward

In 2012 and 2011, we recognized federal net income tax operating losses of $366 million and $226 million, respectively, driven primarily by bonus depreciation, pension plan contributions and other book-versus-tax temporary differences. We also had state net income tax operating loss carryforwards as indicated in the table below.

State	State Net Income Tax Operating Loss Carryforward	Year of Expiration
	(in millions)	
Louisiana	$ 314	2027
Oklahoma	137	2031
Tennessee	13	2026
Virginia	329	2031
West Virginia	897	2032

As a result, we accrued deferred federal, state and local income tax benefits in 2012 and 2011. We expect to realize the federal, state and local cash flow benefits in future periods as there was insufficient capacity in prior periods to carry the net operating losses back. We anticipate future taxable income will be sufficient to realize the net income tax operating loss tax benefits before the federal carryforward expires after 2032.

Tax Credit Carryforward

Federal and state net income tax operating losses sustained in 2012, 2011 and 2009, along with lower federal and state taxable income in 2010, resulted in unused federal and state income tax credits. As of December 31, 2012, we have total federal tax credit carryforwards of $104 million and total state tax credit carryforwards of $82 million, not all of which are subject to an expiration date. If these credits are not utilized, the federal general business tax credits of $70 million will expire in the years 2028 through 2031 and the state coal tax credits of $29 million will expire in the years 2013 through 2021.

We anticipate future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused. We do not anticipate state taxable income will be sufficient in future periods to realize the tax benefits of all state income tax credits before they expire and we have provided a valuation allowance accordingly.

Valuation Allowance

We assess past results and future operations to estimate and evaluate available positive and negative evidence to evaluate whether sufficient future taxable income will be generated to use existing deferred tax assets. A significant piece of objective negative information evaluated was the net income tax operating losses sustained in 2012, 2011 and 2009. On the basis of this evaluation of available positive and negative evidence, as of December 31, 2012, a valuation allowance of $36 million for state tax credits, net of federal tax, and $56 million for an unrealized capital loss has been recorded in order to measure only the portion of the deferred tax assets that, more likely than not, will be realized. The amount of the deferred tax assets considered realizable, however, could be adjusted if estimates of future taxable income during the carryforward period are materially impacted or if objective negative evidence in the form of cumulative losses is no longer present and additional weight may be given to subjective evidence, such as our projections for growth.

For a discussion of the tax implications of the unrealized capital loss resulting from our settlement with BOA and Enron, see "Enron Bankruptcy" section of Note 6.

Uncertain Tax Positions

We recognize interest accruals related to uncertain tax positions in interest income or expense, as applicable, and penalties in Other Operation expense 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,		
	2012	**2011**	**2010**
		(in millions)	
Interest Expense	$ 11	$ 8	$ 8
Interest Income	-	22	11
Reversal of Prior Period Interest Expense	1	13	5

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

	December 31,	
	2012	**2011**
	(in millions)	
Accrual for Receipt of Interest	$ -	$ 13
Accrual for Payment of Interest and Penalties	7	6

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

	2012	**2011**	**2010**
		(in millions)	
Balance as of January 1,	$ 168	$ 219	$ 237
Increase - Tax Positions Taken During a Prior Period	23	51	40
Decrease - Tax Positions Taken During a Prior Period	(16)	(43)	(43)
Increase - Tax Positions Taken During the Current Year	121	10	-
Decrease - Tax Positions Taken During the Current Year	-	-	(6)
Decrease - Settlements with Taxing Authorities	(25)	(31)	(2)
Decrease - Lapse of the Applicable Statute of Limitations	(4)	(38)	(7)
Balance as of December 31,	$ 267	$ 168	$ 219

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $149 million, $111 million and $112 million for 2012, 2011 and 2010, respectively. We believe there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

The American Recovery and Reinvestment Tax 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 materially impact net income or financial condition. However, the bonus depreciation contributed to the 2009 federal net operating tax loss that resulted in a 2010 cash flow benefit of $419 million.

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. Due to 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 did not materially impact cash flows or financial condition. For the year ended December 31, 2010, deferred tax assets decreased $56 million, partially offset by recording net tax regulatory assets of $35 million in our jurisdictions with regulated operations, resulting in a decrease in net income of $21 million.

The Small Business Jobs Act (the 2010 Act) was enacted in September 2010. Included in the 2010 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 2010 Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2011 and 2010. The enacted provisions will not materially impact net income or financial condition but had a favorable impact on cash flows of $318 million in 2010.

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. In November 2012, the effective date was moved to tax years beginning in 2014. Further, the notice stated that the U.S. Treasury Department anticipates that the final regulations will contain changes from the temporary regulations. We will evaluate the impact of these regulations once they are issued.

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

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 8.5% Indiana corporate income tax rate will be reduced 0.5% each year beginning after June 30, 2012 with the final reduction occurring in years beginning after June 30, 2015.

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 2012, the state of West Virginia achieved certain minimum levels of shortfall reserve funds. As a result, the West Virginia corporate income tax rate will be reduced from 7.75% to 7.0% in 2013. The enacted provisions will not materially impact net income, cash flows or financial condition.

12. LEASES

Leases of property, plant and equipment are for periods up to 60 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 Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Additionally, for regulated operations with capital leases, a capital lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

	Years Ended December 31,		
Lease Rental Costs	**2012**	**2011**	**2010**
		(in millions)	
Net Lease Expense on Operating Leases	$ 346	$ 343	$ 343
Amortization of Capital Leases	73	72	97
Interest on Capital Leases	29	32	26
Total Lease Rental Costs	$ 448	$ 447	$ 466

The following table shows the property, plant and equipment under capital leases and related obligations recorded on the balance sheets. Capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on the balance sheets.

	December 31,	
Property, Plant and Equipment Under Capital Leases	**2012**	**2011**
	(in millions)	
Generation	$ 117	$ 104
Other Property, Plant and Equipment	495	485
Total Property, Plant and Equipment Under Capital Leases	612	589
Accumulated Amortization	173	137
Net Property, Plant and Equipment Under Capital Leases	$ 439	$ 452
Obligations Under Capital Leases		
Noncurrent Liability	$ 375	$ 384
Liability Due Within One Year	74	74
Total Obligations Under Capital Leases	$ 449	$ 458

Future minimum lease payments consisted of the following as of December 31, 2012:

Future Minimum Lease Payments	**Capital Leases**	**Noncancelable Operating Leases**
	(in millions)	
2013	$ 95	$ 302
2014	79	275
2015	65	257
2016	59	233
2017	63	219
Later Years	244	1,034
Total Future Minimum Lease Payments	605	$ 2,320
Less Estimated Interest Element	156	
Estimated Present Value of Future Minimum Lease Payments	$ 449	

Master Lease Agreements

We lease certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, we are committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of December 31, 2012, the maximum potential loss for these lease agreements was approximately $19 million assuming the fair value of the equipment is zero at the end of the lease term. Obligations under these master lease agreements are included in the future minimum lease payments schedule earlier in this note.

Rockport Lease

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

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it equally to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. AEP, AEGCo and I&M have no ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2012 are as follows:

Future Minimum Lease Payments	AEGCo	I&M
	(in millions)	
2013	$ 74	$ 74
2014	74	74
2015	74	74
2016	74	74
2017	74	74
Later Years	369	369
Total Future Minimum Lease Payments	$ 739	$ 739

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 operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $14 million for I&M and $15 million for SWEPCo for the remaining railcars as of December 31, 2012. These obligations are 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 and SWEPCo have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is approximately $12 million and SWEPCo's is approximately $13 million assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair value would produce a sufficient sales price to avoid any loss.

Sabine Dragline Lease

During 2009, Sabine, an entity consolidated in accordance with the accounting guidance for "Variable Interest Entities," entered into capital lease arrangements with a nonaffiliated company to finance the purchase of two electric draglines to be used for Sabine's mining operations totaling $47 million. The amounts included in the lease represented the aggregate fair value of the existing equipment and a sale-and-leaseback transaction for additional dragline rebuild costs required to keep the dragline operational. These capital lease assets are included in Other Property, Plant and Equipment on our December 31, 2012 and 2011 balance sheets. The short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on our December 31, 2012 and 2011 balance sheets. The future payment obligations are included in our future minimum lease payments schedule earlier in this note.

I&M 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 had a variable rate based on one month LIBOR and was accounted for as a capital lease with lease terms up to 60 months. This lease was terminated with the March 2012 refueling.

13. FINANCING ACTIVITIES

AEP Common Stock

Listed below is a reconciliation of common stock share activity for the years ended December 31, 2012, 2011 and 2010:

Shares of AEP Common Stock	Issued	Held in Treasury
Balance, December 31, 2009	498,333,265	20,278,858
Issued	2,781,616	-
Treasury Stock Acquired	-	28,867
Balance, December 31, 2010	501,114,881	20,307,725
Issued	2,644,579	-
Treasury Stock Acquired	-	28,867
Balance, December 31, 2011	503,759,460	20,336,592
Issued	2,245,502	-
Balance, December 31, 2012	506,004,962	20,336,592

Preferred Stock

In December 2011, AEP subsidiaries redeemed all of their outstanding preferred stock with a par value of $60 million at a premium, resulting in a $2.8 million loss, which is included in Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense on the statement of income.

Long-term Debt

The following details long-term debt outstanding as of December 31, 2012 and 2011:

Type of Debt and Maturity	Weighted Average Interest Rate as of December 31, 2012	Interest Rate Ranges as of December 31, 2012	2011		Outstanding as of December 31, 2012	2011
					(in millions)	
Senior Unsecured Notes (a)						
2012-2042	5.46%	0.685%-8.13%	0.955%-8.13%	$	12,712	$ 11,737
Pollution Control Bonds (b)						
2012-2038 (c)	3.58%	0.11%-6.30%	0.06%-6.30%		1,958	2,112
Notes Payable (d)						
2012-2032	4.35%	1.913%-8.03%	2.029%-8.03%		427	402
Securitization Bonds (e)						
2013-2024	4.21%	0.88%-6.25%	4.98%-6.25%		2,281	1,688
Junior Subordinated Debentures (a)						
2063			8.75%		-	315
Spent Nuclear Fuel Obligation (f)					265	265
Other Long-term Debt (g)						
2015-2059	2.63%	1.72%-13.718%	3.00%-13.718%		140	29
Fair Value of Interest Rate Hedges					3	7
Unamortized Discount, Net					(29)	(39)
Total Long-term Debt Outstanding					17,757	16,516
Long-term Debt Due Within One Year					2,171	1,433
Long-term Debt				$	15,586	$ 15,083

(a) In 2012, AEP issued $850 million of Senior Unsecured Notes used to retire $243 million of Senior Unsecured Notes and $315 million of Junior Subordinated Debentures.
(b) 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.
(c) Certain pollution control bonds are subject to redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year on the balance sheets.
(d) Notes payable represent outstanding promissory notes issued under term loan agreements and credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.
(e) In 2012, AEP Texas Central Transition Funding III LLC issued $800 million of Securitization Bonds (see Note 15).
(f) Spent nuclear fuel obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see "SNF Disposal" section of Note 5).
(g) In 2012, I&M issued a $110 million three-year credit facility to be used for general corporate purposes.

Long-term debt outstanding as of December 31, 2012 is payable as follows:

	2013	2014	2015	2016	2017	After 2017	Total
				(in millions)			
Principal Amount	$ 2,171	$ 1,169	$ 1,438	$ 840	$ 1,655	$ 10,513	$ 17,786
Unamortized Discount, Net							(29)
Total Long-term Debt Outstanding							$ 17,757

In January 2013 and February 2013, I&M retired $12 million and $11 million, respectively, of Notes Payable related to DCC Fuel.

In January 2013, TCC retired $105 million of its outstanding Securitization Bonds.

In February 2013, OPCo retired $250 million of 5.5% Senior Unsecured Notes due in 2013.

As of December 31, 2012, trustees held, on our behalf, $583 million of our reacquired Pollution Control Bonds.

Dividend Restrictions

Parent Restrictions

The holders of our common stock are entitled to receive the dividends declared by our Board of Directors provided funds are legally available for such dividends. Our income derives from our common stock equity in the earnings of our utility subsidiaries.

Pursuant to the leverage restrictions in our credit agreements, we must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization of the company distributing the dividend. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements. None of AEP's retained earnings were restricted for the purpose of the payment of dividends.

Utility Subsidiaries' Restrictions

Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends. Specifically, several of our public utility subsidiaries have credit agreements that contain a covenant that limits their debt to capitalization ratio to 67.5%. As of December 31, 2012, the amount of restricted net assets of AEP's subsidiaries that may not be distributed to Parent in the form of a loan, advance or dividend was approximately $6 billion.

The Federal Power Act prohibits the utility subsidiaries from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." The term "capital account" is not defined in the Federal Power Act or its regulations. Management understands "capital account" to mean the book value of the common stock. This restriction does not limit the ability of the utility subsidiaries to pay dividends out of retained earnings.

Lines of Credit and Short-term Debt

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of December 31, 2012, we had credit facilities totaling $3.25 billion to support our commercial paper program. The maximum amount of commercial paper outstanding during 2012 was $1.2 billion and the weighted average interest rate of commercial paper outstanding during 2012 was 0.44%. Our outstanding short-term debt was as follows:

	December 31, 2012		December 31, 2011	
Type of Debt	**Outstanding Amount (in millions)**	**Interest Rate (a)**	**Outstanding Amount (in millions)**	**Interest Rate (a)**
Securitized Debt for Receivables (b)	$ 657	0.26 %	$ 666	0.27 %
Commercial Paper	321	0.42 %	967	0.51 %
Line of Credit – Sabine (c)	3	1.82 %	17	1.79 %
Total Short-term Debt	$ 981		$ 1,650	

(a) Weighted average rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.
(c) This line of credit does not reduce available liquidity under AEP's credit facilities.

Credit Facilities

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

Securitized Accounts Receivable – AEP Credit

AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the receivables AEP Credit acquires from affiliated utility subsidiaries. AEP Credit continues to service the receivables. These securitized transactions allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables and accelerate AEP Credit's cash collections.

In 2012, we renewed AEP Credit's receivables securitization agreement. The agreement provides a commitment of $700 million from bank conduits to finance receivables from AEP Credit. A commitment of $385 million expires in June 2013 and the remaining commitment of $315 million expires in June 2015.

Accounts receivable information for AEP Credit is as follows:

	Years Ended December 31, 2012	2011	2010
	(dollars in millions)		
Effective Interest Rates on Securitization of Accounts Receivable	0.26 %	0.27 %	0.31 %
Net Uncollectible Accounts Receivable Written Off	$ 29	$ 37	$ 22

	December 31, 2012	2011
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 835	$ 902
Total Principal Outstanding	657	666
Delinquent Securitized Accounts Receivable	37	38
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	21	18
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	316	370

Customer accounts receivable retained and securitized for our operating companies are managed by AEP Credit. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

14. STOCK-BASED COMPENSATION

As approved by shareholder vote, the Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP) authorizes the use of 20,000,000 shares of AEP common stock for various types of stock-based compensation awards, including stock options, to employees. A maximum of 10,000,000 shares may be used under this plan for full value share awards, which includes performance units, restricted shares and restricted stock units. As of December 31, 2012, 17,907,559 shares remained available for issuance under the LTIP plan. The AEP Board of Directors and shareholders last approved the LTIP in 2010. The following sections provide further information regarding each type of stock-based compensation award granted by the Human Resources Committee of the Board of Directors (HR Committee).

Stock Options

We did not grant stock options in 2012, 2011 or 2010 but we do have outstanding stock options from grants in earlier periods that were exercised in these years. The exercise price of all outstanding stock options equaled or exceeded the market price of AEP's common stock on the date of grant. All outstanding stock options were granted with a ten-year term and generally vested, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1 of the year following the first, second and third anniversary of the grant date. We record compensation cost for stock options over the vesting period based on the fair value on the grant date. The LTIP does not specify a maximum contractual term for stock options.

The total intrinsic value of options exercised is as follows:

Stock Options	Years Ended December 31, 2012	2011	2010
	(in thousands)		
Intrinsic Value of Options Exercised (a)	$ 1,699	$ 1,202	$ 2,058

(a) Intrinsic value is calculated as market price at exercise dates less the option exercise price.

A summary of AEP stock option transactions during the years ended December 31, 2012, 2011 and 2010 is as follows:

	2012		2011		2010	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
	(in thousands)		(in thousands)		(in thousands)	
Outstanding as of January 1,	321	$ 29.35	551	$ 32.88	1,089	$ 32.78
Granted	-	NA	-	NA	-	NA
Exercised/Converted	(128)	28.21	(104)	27.39	(448)	31.53
Forfeited/Expired	(5)	27.26	(126)	46.40	(90)	38.44
Outstanding as of December 31,	188	30.17	321	29.35	551	32.88
Options Exercisable as of December 31,	188	$ 30.17	321	$ 29.35	551	$ 32.88

NA Not applicable.

The following table summarizes information about AEP stock options outstanding and exercisable as of December 31, 2012:

2012 Range of Exercise Prices	Number of Options Outstanding and Exercisable	Weighted Average Remaining Life	Weighted Average Exercise Price	Aggregate Intrinsic Value
	(in thousands)	(in years)		(in thousands)
$27.95 - $30.76	188	0.99	$ 30.17	$ 2,358

We include the proceeds received from exercised stock options in common stock and paid-in capital.

Performance Units

Our performance units have a fair value upon vesting equal to the average closing market price of AEP common stock for the last 20 trading days of the performance period. The number of performance units held is multiplied by the performance score to determine the actual number of performance units realized. The performance score can range from 0% to 200% and is determined at the end of the performance period based on performance measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the HR Committee. Performance units are paid in cash, unless they are needed to satisfy a participant's stock ownership requirement. In that case, the number of units needed to satisfy the participant's largest stock ownership requirement is mandatorily deferred as AEP Career Shares until after the end of the participant's AEP career. AEP Career Shares are a form of non-qualified deferred compensation that has a value equivalent to shares of AEP common stock. AEP Career Shares are paid in cash after the participant's termination of employment. Amounts equivalent to cash dividends on both performance units and AEP Career Shares accrue as additional units. We record compensation cost for performance units over the three-year vesting period. The liability for both the performance units and AEP Career Shares, recorded in Employee Benefits and Pension Obligations on the balance sheets, is adjusted for changes in value. The fair value of performance unit awards is based on the estimated performance score and the current 20-day average closing price of AEP common stock at the date of valuation.

The HR Committee awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the years ended December 31, 2012, 2011 and 2010 as follows:

Performance Units	Years Ended December 31, 2012	2011	2010
Awarded Units (in thousands)	546	7	736
Weighted Average Unit Fair Value at Grant Date	$ 41.38	$ 38.39	$ 35.43
Vesting Period (in years)	3	3	3

Performance Units and AEP Career Shares (Reinvested Dividends Portion)	Years Ended December 31, 2012	2011	2010
Awarded Units (in thousands)	138	198	211
Weighted Average Grant Date Fair Value	$ 40.97	$ 37.31	$ 34.70
Vesting Period (in years)	(a)	(a)	(a)

(a) The vesting period for the reinvested dividends on performance units is equal to the remaining life of the related performance units. Dividends on AEP Career Shares vest immediately upon grant but are not paid in cash until after the participant's termination of employment.

Performance scores and final awards are determined and certified by the HR Committee in accordance with the pre-established performance measures within approximately a month after the end of the performance period. The HR Committee has discretion to reduce or eliminate the number of performance units earned but may not increase the number earned. The performance scores for all open performance periods prior to those granted in 2012 are dependent on two equally-weighted performance measures: (a) three-year total shareholder return measured relative to the electric utility and multi utility sub-industry segments of the Standard and Poor's 500 Index and (b) three-year cumulative earnings per share measured relative to an AEP Board of Directors approved target. For the performance units granted in 2012, the three-year total shareholder return peer group was changed to the S&P 500 Electric Utility Index.

The certified performance scores and units earned for the three-year period ended December 31, 2012, 2011 and 2010 were as follows:

Performance Units	Years Ended December 31, 2012	2011	2010
Certified Performance Score	99.7 %	89.8 %	55.8 %
Performance Units Earned	1,096,572	1,216,926	489,013
Performance Units Mandatorily Deferred as AEP Career Shares	51,056	52,639	33,501
Performance Units Voluntarily Deferred into the Incentive Compensation Deferral Program	26,337	42,502	6,583
Performance Units to be Paid in Cash	1,019,179	1,121,785	448,929

The cash payouts for the years ended December 31, 2012, 2011 and 2010 were as follows:

Performance Units and AEP Career Shares	Years Ended December 31, 2012	2011	2010
		(in thousands)	
Cash Payouts for Performance Units	$ 44,968	$ 15,985	$ 18,683
Cash Payouts for AEP Career Share Distributions	11,027	2,777	3,594

Restricted Shares and Restricted Stock Units

In 2004, the independent members of the AEP Board of Directors granted 300,000 restricted shares to the then Chairman, President and CEO upon the commencement of his AEP employment. Of these restricted shares, 50,000 vested on January 1, 2005, 50,000 vested on January 1, 2006, 66,666 vested on November 30, 2009, 66,667 vested on November 30, 2010 and 66,667 vested on November 30, 2011. Compensation cost for restricted shares is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of shares granted by the grant date market closing price, which was $30.76. The maximum contractual term for these restricted shares was eight years and dividends on these restricted shares were paid in cash. AEP has not granted other restricted shares.

The HR Committee also grants restricted stock units (RSUs), which generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments. Additional RSUs granted as dividends vest on the same date as the underlying RSUs on which the dividends were awarded. Compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of units granted by the grant date market closing price. The maximum contractual term of outstanding RSUs is six years from the grant date.

In 2010, the HR Committee granted a total of 165,520 RSUs to four CEO succession candidates as a retention incentive for these candidates. These grants vest, subject to the candidates' continuous employment, in three approximately equal installments on August 3, 2013, August 3, 2014 and August 3, 2015.

The HR Committee awarded RSUs, including units awarded for dividends, for the years ended December 31, 2012, 2011 and 2010 as follows:

	Years Ended December 31,		
Restricted Stock Units	**2012**	**2011**	**2010**
Awarded Units (in thousands)	497	121	873
Weighted Average Grant Date Fair Value	$ 40.69	$ 37.07	$ 35.24

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the years ended December 31, 2012, 2011 and 2010 were as follows:

	Years Ended December 31,		
Restricted Shares and Restricted Stock Units	**2012**	**2011**	**2010**
		(in thousands)	
Fair Value of Restricted Shares and Restricted Stock Units Vested	$ 10,608	$ 7,164	$ 6,044
Intrinsic Value of Restricted Shares and Restricted Stock Units Vested (a)	12,157	8,017	5,993

(a) Intrinsic value is calculated as market price at exercise date.

A summary of the status of our nonvested RSUs as of December 31, 2012 and changes during the year ended December 31, 2012 are as follows:

Nonvested Restricted Stock Units	**Shares/Units**	**Weighted Average Grant Date Fair Value**
	(in thousands)	
Nonvested as of January 1, 2012	903	$ 35.46
Granted	497	40.69
Vested	(306)	34.64
Forfeited	(94)	35.95
Nonvested as of December 31, 2012	1,000	38.22

The total aggregate intrinsic value of nonvested RSUs as of December 31, 2012 was $43 million and the weighted average remaining contractual life was 2.14 years.

Other Stock-Based Plans

We also have a Stock Unit Accumulation Plan for Non-employee Directors providing each non-employee director with AEP stock units as a substantial portion of their quarterly compensation for their services as a director. The number of stock units provided is based on the closing price of AEP common stock on the last trading day of the quarter for which the stock units were earned. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The stock units granted to non-employee directors are fully vested upon grant date. Stock units are paid in cash upon termination of board service or up to 10 years later if the participant so elects. Cash payments for stock units are calculated based on the average closing price of AEP common stock for the last 20 trading days prior to the distribution date.

We record compensation cost for stock units when the units are awarded and adjust the liability for changes in value based on the current 20-day average closing price of AEP common stock on the valuation date.

We had no material cash payouts for stock unit distributions for the years ended December 31, 2012, 2011 and 2010.

The Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2012, 2011 and 2010 as follows:

	Years Ended December 31,		
Stock Unit Accumulation Plan for Non-Employee Directors	**2012**	**2011**	**2010**
Awarded Units (in thousands)	52	52	54
Weighted Average Grant Date Fair Value	$ 41.20	$ 37.72	$ 34.67

Share-based Compensation Plans

Compensation cost and the actual tax benefit realized for the tax deductions from compensation cost for share-based payment arrangements recognized in income and total compensation cost capitalized in relation to the cost of an asset for the years ended December 31, 2012, 2011 and 2010 were as follows:

	Years Ended December 31,		
Share-based Compensation Plans	**2012**	**2011**	**2010**
		(in thousands)	
Compensation Cost for Share-based Payment Arrangements (a)	$ 51,767	$ 61,807	$ 28,116
Actual Tax Benefit Realized	18,119	21,632	9,841
Total Compensation Cost Capitalized	10,707	11,608	4,689

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance expenses on the statements of income.

During the years ended December 31, 2012, 2011 and 2010, there were no significant modifications affecting any of our share-based payment arrangements.

As of December 31, 2012, there was $47 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the LTIP. Unrecognized compensation cost related to the performance units and AEP Career Shares will change as the fair value is adjusted each period and forfeitures for all award types are realized. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.53 years.

Cash received from stock options exercised and actual tax benefit realized for the tax deductions from stock options exercised during the years ended December 31, 2012, 2011 and 2010 were as follows:

	Years Ended December 31,		
Share-based Compensation Plans	**2012**	**2011**	**2010**
		(in thousands)	
Cash Received from Stock Options Exercised	$ 3,598	$ 2,855	$ 14,134
Actual Tax Benefit Realized for the Tax Deductions from Stock Options Exercised	618	411	706

Our practice is to use authorized but unissued shares to fulfill share commitments for stock option exercises and RSU vesting. Although we do not currently anticipate any changes to this practice, we are permitted to use treasury shares, shares acquired in the open market specifically for distribution under the LTIP or any combination thereof for this purpose. The number of new shares issued to fulfill vesting RSUs is generally reduced to offset our tax withholding obligation.

In February 2013, the HR Committee granted approximately $40 million in share-based awards. This amount will be allocated between 2013-2015 performance units and restricted stock units vesting over 40 months.

15. VARIABLE INTEREST ENTITIES

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether we are the primary beneficiary of a VIE, we consider factors such as equity at risk, the amount of the VIE's variability we absorb, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. We believe that significant assumptions and judgments were applied consistently.

We are the primary beneficiary of Sabine, DCC Fuel, AEP Credit, Transition Funding and a protected cell of EIS. In addition, we have not provided material financial or other support to Sabine, DCC Fuel, Transition Funding, our protected cell of EIS and AEP Credit that was not previously contractually required. We hold a significant variable interest in DHLC and Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series).

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the years ended December 31, 2012, 2011 and 2010 were $147 million, $128 million and $133 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on the balance sheets.

Our subsidiaries participate in one protected cell of EIS for approximately ten lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. Our subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on our control and the structure of the protected cell and EIS, management concluded that we are the primary beneficiary of the protected cell and are required to consolidate its assets and liabilities. Our insurance premium payments to the protected cell for the years ended December 31, 2012, 2011 and 2010 were $32 million, $48 million and $35 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on the balance sheets. The amount reported as equity is the protected cell's policy holders' surplus.

I&M has nuclear fuel lease agreements with DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, DCC Fuel IV LLC and DCC Fuel V LLC (collectively DCC Fuel). DCC Fuel was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the years ended December 31, 2012, 2011 and 2010 were $127 million, $85 million and $59 million, respectively. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the respective lease terms, which do not exceed 54 months. Based on our control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on the balance sheets.

AEP Credit is a wholly-owned subsidiary of AEP. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides a minimum of 5% equity and up to 20% of AEP Credit's short-term borrowing needs in excess of third party financings. Any third party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on our control of AEP Credit, management has concluded that we are the primary beneficiary and are required to consolidate its assets and liabilities. See the tables below for the classification of AEP Credit's assets and liabilities on the balance sheets. See "Securitized Accounts Receivables – AEP Credit" section of Note 13.

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. Management has concluded that TCC is the primary beneficiary of Transition Funding because TCC has the power to direct the most significant activities of the VIE and TCC's equity interest could potentially be significant. Therefore, TCC is required to consolidate Transition Funding. The securitized bonds totaled $2.3 billion and $1.7 billion as of December 31, 2012 and 2011, respectively, and are included in current and long-term debt on the balance sheets. Transition Funding has securitized transition assets of $2.1 billion and $1.6 billion as of December 31, 2012 and 2011, respectively, which are presented separately on the face of the balance sheets. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from TCC under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to TCC or any other AEP entity. TCC acts as the servicer for Transition Funding's securitized transition assets and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Transition Funding's assets and liabilities on the balance sheets.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2012
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	Protected Cell of EIS	AEP Credit	TCC Transition Funding
ASSETS					
Current Assets	$ 57	$ 133	$ 130	$ 843	$ 250
Net Property, Plant and Equipment	170	176	-	-	-
Other Noncurrent Assets	55	92	4	1	2,167 (a)
Total Assets	$ 282	$ 401	$ 134	$ 844	$ 2,417
LIABILITIES AND EQUITY					
Current Liabilities	$ 32	$ 121	$ 43	$ 800	$ 304
Noncurrent Liabilities	250	280	66	1	2,095
Equity	-	-	25	43	18
Total Liabilities and Equity	$ 282	$ 401	$ 134	$ 844	$ 2,417

(a) Includes an intercompany item eliminated in consolidation of $89 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2011
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	Protected Cell of EIS	AEP Credit	TCC Transition Funding
ASSETS					
Current Assets	$ 48	$ 118	$ 121	$ 910	$ 220
Net Property, Plant and Equipment	154	188	-	-	-
Other Noncurrent Assets	42	118	6	1	1,580
Total Assets	$ 244	$ 424	$ 127	$ 911	$ 1,800
LIABILITIES AND EQUITY					
Current Liabilities	$ 68	$ 103	$ 40	$ 864	$ 229
Noncurrent Liabilities	176	321	71	1	1,557
Equity	-	-	16	46	14
Total Liabilities and Equity	$ 244	$ 424	$ 127	$ 911	$ 1,800

DHLC is a mining operator that sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and voting rights equally. Each entity guarantees 50% of DHLC's debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. SWEPCo's total billings from DHLC for the years ended December 31, 2012, 2011 and 2010 were $77 million, $62 million and $56 million, respectively. We are not required to consolidate DHLC as we are not the primary beneficiary, although we hold a significant variable interest in DHLC. Our equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on the balance sheets.

Our investment in DHLC was:

	December 31, 2012 As Reported on the Balance Sheet	2012 Maximum Exposure	2011 As Reported on the Balance Sheet	2011 Maximum Exposure
	(in millions)			
Capital Contribution from SWEPCo	$ 8	$ 8	$ 8	$ 8
Retained Earnings	1	1	1	1
SWEPCo's Guarantee of Debt	-	49	-	52
Total Investment in DHLC	$ 9	$ 58	$ 9	$ 61

We and FirstEnergy Corp. (FirstEnergy) have a joint venture in Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct, through its operating companies, a high-voltage transmission line project in the PJM region. PATH consists of the "West Virginia Series (PATH-WV)," owned equally by subsidiaries of FirstEnergy and AEP, and the "Allegheny Series" which is 100% owned by a subsidiary of FirstEnergy. Provisions exist within the PATH-WV agreement that make it a VIE. The "Allegheny Series" is not considered a VIE. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant variable interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the balance sheets. We and FirstEnergy share the returns and losses equally in PATH-WV. Our subsidiaries and FirstEnergy's subsidiaries provide services to the PATH companies through service agreements. The entities recover costs through regulated rates.

In August 2012, the PJM board cancelled the PATH Project, our transmission joint venture with FirstEnergy, and removed it from the 2012 Regional Transmission Expansion Plan. In November 2012, the FERC issued an order accepting AEP's and FirstEnergy's abandonment cost recovery filing which requested authority to recover prudently-incurred costs associated with the PATH Project. The FERC also set the issue of prudency of costs for settlement proceedings.

Our investment in PATH-WV was:

	December 31, 2012 As Reported on the Balance Sheet	2012 Maximum Exposure	2011 As Reported on the Balance Sheet	2011 Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$ 19	$ 19	$ 19	$ 19
Retained Earnings	12	12	10	10
Total Investment in PATH-WV	$ 31	$ 31	$ 29	$ 29

16. PROPERTY, PLANT AND EQUIPMENT

Depreciation, Depletion and Amortization

We provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following tables provide the annual property information:

2012	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(in millions)			(in years)	(in millions)			(in years)
Generation	$ 16,973	$ 6,962	1.7 - 3.8 %	31 - 132	$ 9,306	$ 3,526	2.6 - 3.3 %	35 - 66
Transmission	9,846	2,720	1.2 - 2.8 %	25 - 87	-	-	NA	NA
Distribution	15,565	3,837	2.4 - 3.9 %	11 - 75	-	-	NA	NA
CWIP	1,600	(27)	NM	NM	219	1	NM	NM
Other	2,644	1,238	1.8 - 9.6 %	5 - 75	1,301	434	NM	NM
Total	$ 46,628	$ 14,730			$ 10,826	$ 3,961		

2011	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(in millions)			(in years)	(in millions)			(in years)
Generation	$ 14,804	$ 6,692	1.6 - 3.8 %	9 - 132	$ 10,134	$ 3,904	2.6 - 3.5 %	20 - 66
Transmission	9,048	2,600	1.3 - 2.7 %	25 - 87	-	-	NA	NA
Distribution	14,783	3,828	2.4 - 4.0 %	11 - 75	-	-	NA	NA
CWIP	2,913 (a)	36	NM	NM	208	1	NM	NM
Other	2,587	1,246	1.7 - 9.3 %	5 - 55	1,193	392	NM	NM
Total	$ 44,135	$ 14,402			$ 11,535	$ 4,297		

2010	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
		(in years)		(in years)
Generation	1.6 - 3.8 %	9 - 132	2.2 - 5.1 %	20 - 70
Transmission	1.4 - 3.0 %	25 - 87	NA	NA
Distribution	2.4 - 3.9 %	11 - 75	NA	NA
CWIP	NM	NM	NM	NM
Other	3.0 - 12.5 %	5 - 55	NM	NM

(a) Includes CWIP related to SWEPCo's Arkansas jurisdictional share of the Turk Plant.
NA Not applicable.
NM Not meaningful.

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense.

For rate-regulated operations, the composite depreciation rate generally includes a component for non-asset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

Asset Retirement Obligations (ARO)

We record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for our legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, closure and monitoring of underground carbon storage facilities at Mountaineer Plant, wind farms and certain coal mining facilities, as well as for nuclear decommissioning of our Cook Plant. We have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. We do not estimate the retirement for such easements because we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements, which is not expected.

The following is a reconciliation of the 2012 and 2011 aggregate carrying amounts of ARO:

	Carrying Amount of ARO
	(in millions)
ARO as of December 31, 2010	$ 1,398
Accretion Expense	82
Liabilities Incurred	7
Liabilities Settled	(26)
Revisions in Cash Flow Estimates	13
ARO as of December 31, 2011 (a)	1,474
Accretion Expense	85
Liabilities Incurred	17
Liabilities Settled	(24)
Revisions in Cash Flow Estimates	144
ARO as of December 31, 2012	$ 1,696

(a) The current portion of our ARO, totaling $2 million, is included in Other Current Liabilities on our 2011 balance sheet.

As of December 31, 2012 and 2011, our ARO liability was $1.7 billion and $1.5 billion, respectively, and included $1.2 billion and $979 million, respectively, for nuclear decommissioning of the Cook Plant. As of December 31, 2012 and 2011, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $1.4 billion and $1.3 billion, respectively, and are recorded in Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

Our amounts of allowance for borrowed, including interest capitalized, and equity funds used during construction is summarized in the following table:

	Years Ended December 31,		
	2012	2011	2010
		(in millions)	
Allowance for Equity Funds Used During Construction	$ 93	$ 98	$ 77
Allowance for Borrowed Funds Used During Construction	69	63	53

Jointly-owned Electric Facilities

We have electric facilities that are jointly-owned with nonaffiliated companies. Using our own financing, we are obligated to pay a share of the costs of these jointly-owned facilities in the same proportion as our ownership interest. Our proportionate share of the operating costs associated with such facilities is included on the statements of income and the investments and accumulated depreciation are reflected on the balance sheets under Property, Plant and Equipment as follows:

	Fuel Type	Percent of Ownership	Company's Share as of December 31, 2012 Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	$ -	$ -	$ -
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5 %	310	26	59
J.M. Stuart Generating Station (c)	Coal	26.0 %	542	11	181
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	807	2	387
Dolet Hills Generating Station (Unit No. 1) (d)	Lignite	40.2 %	263	8	195
Flint Creek Generating Station (Unit No. 1) (e)	Coal	50.0 %	121	14	64
Pirkey Generating Station (Unit No. 1) (e)	Lignite	85.9 %	514	16	371
Oklaunion Generating Station (Unit No. 1) (f)	Coal	70.3 %	403	4	216
Turk Generating Plant (g)	Coal	73.33 %	1,613	(3)	-
Transmission	NA	(h)	69	4	50
Total			$ 4,642	$ 82	$ 1,523

	Fuel Type	Percent of Ownership	Company's Share as of December 31, 2011 Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	$ 19	$ -	$ 8
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5 %	310	12	54
J.M. Stuart Generating Station (c)	Coal	26.0 %	529	13	172
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	771	20	377
Dolet Hills Generating Station (Unit No. 1) (d)	Lignite	40.2 %	264	-	193
Flint Creek Generating Station (Unit No. 1) (e)	Coal	50.0 %	118	6	63
Pirkey Generating Station (Unit No. 1) (e)	Lignite	85.9 %	513	1	362
Oklaunion Generating Station (Unit No. 1) (f)	Coal	70.3 %	401	2	208
Turk Generating Plant (g)	Coal	73.33 %	-	1,326	-
Transmission	NA	(h)	63	6	50
Total			$ 2,988	$ 1,386	$ 1,487

(a) Operated by Duke Energy Corporation, a nonaffiliated company. AEP's portion of this unit was impaired in the fourth quarter of 2012. See "Impairments" section of Note 6.
(b) Operated by OPCo.
(c) Operated by The Dayton Power & Light Company, a nonaffiliated company.
(d) Operated by CLECO, a nonaffiliated company.
(e) Operated by SWEPCo.
(f) Operated by PSO and also jointly-owned (54.7%) by TNC.
(g) Turk Generating Plant was placed in service in December 2012. SWEPCo jointly owns the plant with Arkansas Electric Cooperative Corporation (11.67%), East Texas Electric Cooperative (8.33%) and Oklahoma Municipal Power Authority (6.67%). Through December 2012, construction costs totaling $457 million have been billed to the other owners.
(h) Varying percentages of ownership.
NA Not applicable.

17. COST REDUCTION PROGRAMS

2012 Sustainable Cost Reductions

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

We recorded a charge to expense during 2012 related to the sustainable cost reductions initiative.

	Total
	(in millions)
Incurred	$ 47
Settled	(22)
Balance as of December 31, 2012	**$ 25**

These expenses relate primarily to severance benefits. They are included primarily in Other Operation expense on the statement of income and Other Current Liabilities on the balance sheet. Approximately 95% of the expense was within the Utility Operations segment.

2010 Cost Reduction Initiatives

In April 2010, we 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. Many of these eliminated positions resulted from employees that elected retirement through voluntary severance. Most of the affected employees terminated employment as of May 31, 2010. The severance program provided two weeks of base pay for every year of service along with other severance benefits.

We recorded a charge of $293 million to Other Operation expense during 2010 primarily related to severance benefits as the result of headcount reduction initiatives.

18. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In our opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of our results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. Our unaudited quarterly financial information is as follows:

	2012 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions - except per share amounts)			
Total Revenues	$ 3,625	$ 3,551	$ 4,156	$ 3,613
Operating Income	754	741	912	249 (a)(b)
Net Income	390	363	488	21 (a)(b)
Amounts Attributable to AEP Common Shareholders:				
Net Income	389	362	487	21 (a)(b)
Basic Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (f)	0.80	0.75	1.00	0.05
Diluted Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (f)	0.80	0.75	1.00	0.05

	2011 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions - except per share amounts)			
Total Revenues	$ 3,730	$ 3,609	$ 4,333	$ 3,444
Operating Income	832	717	890 (c)	343 (e)
Income Before Extraordinary Item	355	353	657 (c) (d)	211 (d) (e)
Extraordinary Item, Net of Tax	-	-	273 (d)	100 (d)
Net Income	355	353	930 (c) (d)	311 (d) (e)
Amounts Attributable to AEP Common Shareholders:				
Income Before Extraordinary Item	353	352	655 (c) (d)	208 (d) (e)
Extraordinary Item, Net of Tax	-	-	273 (d)	100 (d)
Net Income	353	352	928 (c) (d)	308 (d) (e)
Basic Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share Before Extraordinary Item (f)	0.73	0.73	1.35	0.43
Extraordinary Item per Share	-	-	0.57	0.20
Earnings per Share (f)	0.73	0.73	1.92	0.63
Diluted Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share Before Extraordinary Item (f)	0.73	0.73	1.35	0.43
Extraordinary Item per Share	-	-	0.57	0.20
Earnings per Share (f)	0.73	0.73	1.92	0.63

(a) Includes pretax impairments for certain Ohio generation plants (see Note 6).
(b) See Note 17 for discussion of cost reduction programs in 2012.
(c) Includes pretax plant impairments (see Note 6) and a provision for refund of POLR charges in Ohio.
(d) See "TCC Texas Restructuring" section of Note 2 for discussion of gains recorded in the third and fourth quarters of 2011.
(e) Includes a refund of POLR charges in Ohio and OPCo adjustments for fuel disallowances, the 2010 SEET and the obligation to contribute to Partnership with Ohio and Ohio Growth Fund. Also includes a pretax plant impairment for SWEPCo's Turk Plant (see Note 6).
(f) Quarterly Earnings per Share amounts are meant to be stand-alone calculations and are not always additive to full-year amount due to rounding.

19. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2012 and 2011 by operating segment are as follows:

	Utility Operations	AEP River Operations	Generation and Marketing	AEP Consolidated
		(in millions)		
Balance as of December 31, 2010	$ 37	$ 39	$ -	$ 76
Impairment Losses	-	-	-	-
Balance as of December 31, 2011	37	39	-	76
Acquired Goodwill	-	-	15	15
Impairment Losses	-	-	-	-
Balance as of December 31, 2012	$ 37	$ 39	$ 15	$ 91

In the fourth quarters of 2012 and 2011, we performed our annual impairment tests. The fair values of the operations with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses. We do not have any accumulated impairment on existing goodwill.

During 2012, the increase in goodwill of $15 million was due to the acquisition of BlueStar.

Other Intangible Assets

Acquired intangible assets subject to amortization were $24 million as of December 31, 2012, net of accumulated amortization and are included in Deferred Charges and Other Noncurrent Assets on the balance sheets. As of December 31, 2011, all acquired intangible assets had been fully amortized. During 2012, as a result of the acquisition of BlueStar, we acquired intangible assets associated with sales contracts and customer accounts of $58 million. The amortization life, gross carrying amount and accumulated amortization by major asset class are as follows:

		December 31,			
		2012		2011	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)		(in millions)		
Easements	10	$ -	$ -	$ 2	$ 2
Purchased Technology	10	-	-	11	11
Acquired Customer Contracts	5	58	34	-	-
Total		$ 58	$ 34	$ 13	$ 13

Amortization of intangible assets was $34 million, $1 million and $1 million for the years ended December 31, 2012, 2011 and 2010, respectively. Our estimated total amortization is $13 million, $6 million, $3 million and $2 million for 2013, 2014, 2015 and 2016, respectively.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Company Overview

As a public utility, APCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 960,000 retail customers in its service territory in southwestern Virginia and southern West Virginia. APCo consolidates Cedar Coal Company, Central Appalachian Coal Company and Southern Appalachian Coal Company, its wholly-owned subsidiaries. APCo sells power at wholesale to municipalities.

The Interconnection Agreement 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. Members of the Interconnection Agreement are compensated for their costs of energy delivered and charged for energy received. The capacity reserve relationship of the Interconnection Agreement members changes as generating assets are added, retired or sold and relative peak demand changes. The Interconnection Agreement 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. The addition of the Dresden Plant in January 2012 and removal of OPCo's Sporn Plant, Unit 5 in September 2011 changed the capacity reserve relationship of the 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 2010. The new Transmission Agreement will be phased in for retail rates, added KGPCo and WPCo as parties to the agreement and changed the allocation method.

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 APCo's behalf. APCo 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 Interconnection Agreement and the SIA. APCo 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.

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

Regulatory Activity

Plant Transfers and Termination of Interconnection Agreement

Based upon the PUCO's approval of OPCo's corporate separation plan in October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generation assets from its distribution and transmission operations. The AEP East Companies also requested FERC approval to transfer at net book value OPCo's current two-thirds ownership (867 MW) in Amos Plant, Unit 3 to APCo and transfer at net book value OPCo's Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each). Additionally, the AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate their respective power supply resources. Under the PCA, APCo, I&M and KPCo would be individually responsible for planning their respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo, I&M and KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities. Intervenors have opposed several of these filings. The AEP East Companies have responded and continue to pursue approvals from the FERC. A decision from the FERC is expected in mid-2013.

In December 2012, APCo filed requests with the Virginia SCC and the WVPSC for approval of the Amos Plant and Mitchell Plant transfers discussed above. Hearings at the Virginia SCC and the WVPSC are scheduled for April 2013 and July 2013, respectively. If the transfers are approved, APCo anticipates seeking cost recovery when it filed its next base rate case.

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

Securitization of Regulatory Asset

In March 2012, West Virginia passed securitization legislation which allows the WVPSC to establish a regulatory framework to securitize certain deferred ENEC balances and other ENEC related assets. In August 2012, APCo and WPCo filed with the WVPSC a request for a financing order to securitize $422 million related to APCo's December 2011 under-recovered ENEC deferral balance, other ENEC-related assets and related financing costs. In January 2013, intervenors filed testimony that recommended securitization of approximately $370 million. The differences between APCo's and WPCo's request and the intervenors' testimony represent previously approved ENEC-related deferred amounts being recovered in the ENEC over extended periods, various amounts deferred subsequent to the 2011 securitization period and related securitization financing costs. APCo and WPCo are currently in settlement discussions with intervenors.

WPCo Merger with APCo

In December 2011, APCo and WPCo filed an application with the WVPSC requesting approval to merge WPCo into APCo. In December 2012, APCo and WPCo filed merger applications with the Virginia SCC and the FERC. A hearing at the Virginia SCC is scheduled for April 2013.

Litigation and Environmental Issues

In the ordinary course of business, APCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 2 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 353 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2012	**2011**	**2010**
	(in millions of KWhs)		
Retail:			
Residential	11,395	12,011	13,127
Commercial	6,794	6,915	7,208
Industrial	10,778	10,811	10,774
Miscellaneous	820	828	869
Total Retail	29,787	30,565	31,978
Wholesale	8,153	8,376	6,578
Total KWhs	37,940	38,941	38,556

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2012	**2011**	**2010**
	(in degree days)		
Actual - Heating (a)	1,783	1,996	2,636
Normal - Heating (b)	2,265	2,267	2,272
Actual - Cooling (c)	1,354	1,432	1,530
Normal - Cooling (b)	1,201	1,186	1,170

(a) Eastern Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.

2012 Compared to 2011

Reconciliation of Year Ended December 31, 2011 to Year Ended December 31, 2012
Net Income
(in millions)

Year Ended December 31, 2011	$	163
Changes in Gross Margin:		
Retail Margins		279
Off-system Sales		(9)
Transmission Revenues		13
Other Revenues		(15)
Total Change in Gross Margin		268
Changes in Expenses and Other:		
Other Operation and Maintenance		(31)
Depreciation and Amortization		(74)
Taxes Other Than Income Taxes		5
Carrying Costs Income		11
Other Income		(11)
Interest Expense		3
Total Change in Expenses and Other		(97)
Income Tax Expense		(76)
Year Ended December 31, 2012	$	258

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** increased $279 million primarily due to the following:
  - A $130 million increase due to lower capacity settlement expenses under the Interconnection Agreement, net of recovery in West Virginia and environmental deferrals in Virginia. This increase was primarily as a result of a mild winter in 2012 and its impact on APCo's winter peak, APCo's completion of the Dresden Plant in January 2012 and the removal of Sporn Plant Unit 5 from the Interconnection Agreement in September 2011.
  - An $87 million increase due to higher rates in Virginia and West Virginia. Of this increase, $59 million have corresponding increases in Depreciation and Amortization expenses below.
  - A $24 million decrease in other variable electric generation expenses.
  - A $24 million write-off in 2011 related to the disallowance of certain Virginia environmental costs incurred in 2009 and 2010 as a result of the November 2011 Virginia SCC order.
  - A $9 million deferral of additional wind purchase costs as a result of the June 2012 Virginia SCC fuel factor order.
  - A $9 million increase due to adjustments for previously disallowed environmental costs by the November 2011 Virginia SCC order subsequently determined in 2012 to be appropriate for recovery by the Supreme Court of Virginia.
  - A $6 million decrease in PJM expenses.

  These increases were partially offset by:
  - A $24 million decrease in weather-related usage primarily due to an 11% decrease in heating degree days.
  - A $15 million decrease in residential margins primarily due to lower non-weather related usage.
- **Margins from Off-system Sales** decreased $9 million primarily due to lower market prices, lower PJM capacity payments and reduced trading and marketing margins.
- **Transmission Revenues** increased $13 million primarily due to increased Network Integration Transmission Service (NITS) revenue requirements beginning in July 2011. These NITS revenues are offset in Other Operation and Maintenance expenses below.
- **Other Revenues** decreased $15 million primarily due to decreased gains on affiliated emission allowances.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses increased $31 million primarily due to the following:
  - A $32 million increase due to the 2011 deferral of 2009 storm costs and the 2010 cost reduction initiatives as allowed by the WVPSC.
  - A $27 million increase due to the favorable 2011 asset retirement obligation adjustment related to the early closure and previous write-off of the Mountaineer Carbon Capture and Storage Product Validation Facility.
  - A $16 million increase in transmission expenses due to higher NITS expenses. These expenses are offset in Transmission Revenues above.
  - A $10 million increase in provisions for uncollectible accounts.
  - An $8 million increase due to expenses related to the 2012 sustainable cost reductions.

  These increases were partially offset by:
  - A $41 million decrease due to the 2011 write-off of a portion of the West Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the WVPSC.
  - A $13 million decrease due to the deferral of transmission costs for the Virginia Transmission Rate Adjustment Clause as allowed by the Virginia SCC recovered dollar-for-dollar within Gross Margin.
  - A $10 million decrease in generation plant maintenance expenses in 2012.
- **Depreciation and Amortization** expenses increased $74 million primarily due to:
  - A $35 million increase as a result of increased depreciation rates in Virginia effective February 2012. The majority of this increase in depreciation is offset within Gross Margin.
  - An $18 million increase in amortization primarily as a result of the Virginia Environmental Rate Adjustment Clause and the Virginia E&R surcharge, both effective February 2012. This increase in amortization is offset within Gross Margin.
  - A $9 million increase in depreciation due to adjustments for disallowed environmental costs as approved in the November 2011 Virginia SCC order and 2012 adjustments for certain costs subsequently determined by the Supreme Court of Virginia to be appropriate for recovery.
  - A $7 million increase in depreciation as a result of Dresden Plant being placed in service in January 2012.
- **Taxes Other Than Income Taxes** expenses decreased $5 million primarily due to an $8 million decrease in the Virginia Minimum Tax, partially offset by a $3 million increase in real and personal property taxes.
- **Carrying Costs Income** increased $11 million primarily due to adjustments for disallowed environmental costs as approved in the November 2011 Virginia SCC order and 2012 adjustments for certain costs subsequently determined by the Supreme Court of Virginia to be appropriate for recovery.
- **Other Income** decreased $11 million primarily due to:
  - An $8 million decrease in the equity component of AFUDC as a result of the completion of the Dresden Plant in January 2012.
  - A $3 million decrease due to interest income recorded in 2011 for favorable adjustments related to the 2001-2006 federal income tax audit.
- **Interest Expense** decreased $3 million primarily due to lower outstanding long-term debt balances and lower long-term interest rates.
- **Income Tax Expense** increased $76 million primarily due to an increase in pretax book income and by the recording of state income tax adjustments.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 353 for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and pension and other postretirement benefits.

See the "Accounting Pronouncements" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 353 for a discussion of accounting pronouncements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Appalachian Power Company:

We have audited the accompanying consolidated balance sheets of Appalachian Power Company and subsidiaries (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income (loss), changes in common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Appalachian Power Company and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 26, 2013

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Appalachian Power Company and subsidiaries (APCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. APCo's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of APCo's internal control over financial reporting as of December 31, 2012. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management's assessment, APCo's internal control over financial reporting was effective as of December 31, 2012.

This annual report does not include an attestation report of APCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit APCo to provide only management's report in this annual report.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	Years Ended December 31,		
	2012	**2011**	**2010**
REVENUES			
Electric Generation, Transmission and Distribution	$ 2,948,762	$ 2,835,481	$ 2,950,183
Sales to AEP Affiliates	318,199	359,802	316,207
Other Revenues	9,970	9,942	8,713
TOTAL REVENUES	3,276,931	3,205,225	3,275,103
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	815,979	759,684	663,422
Purchased Electricity for Resale	211,133	305,647	257,349
Purchased Electricity from AEP Affiliates	661,238	819,182	917,616
Other Operation	332,936	316,995	429,107
Maintenance	211,702	197,002	211,486
Depreciation and Amortization	344,293	270,529	304,192
Taxes Other Than Income Taxes	102,190	106,606	110,908
TOTAL EXPENSES	2,679,471	2,775,645	2,894,080
OPERATING INCOME	597,460	429,580	381,023
Other Income (Expense):			
Interest Income	1,358	5,016	1,477
Carrying Costs Income	24,602	13,433	33,080
Allowance for Equity Funds Used During Construction	1,684	9,212	2,967
Interest Expense	(202,074)	(204,623)	(207,649)
INCOME BEFORE INCOME TAX EXPENSE	423,030	252,618	210,898
Income Tax Expense	165,527	89,860	74,230
NET INCOME	257,503	162,758	136,668
Preferred Stock Dividend Requirements Including Capital Stock Expense	-	1,745	900
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$ 257,503	$ 161,013	$ 135,768

The common stock of APCo is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	Years Ended December 31, 2012	2011	2010
Net Income	$ 257,503	$ 162,758	$ 136,668
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $925, $123 and $3,843 in 2012, 2011 and 2010, Respectively	1,718	(229)	7,137
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1,937, $1,674 and $2,247 in 2012, 2011 and 2010, Respectively	3,597	3,109	4,172
Pension and OPEB Funded Status, Net of Tax of $12,562, $7,215 and $4,888 in 2012, 2011 and 2010, Respectively	23,330	(13,400)	(9,078)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	28,645	(10,520)	2,231
TOTAL COMPREHENSIVE INCOME	$ 286,148	$ 152,238	$ 138,899

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$ 260,458	$ 1,475,393	$ 1,085,980	$ (50,254)	$ 2,771,577
Common Stock Dividends			(88,000)		(88,000)
Preferred Stock Dividends			(799)		(799)
Capital Stock Expense		103	(101)		2
Subtotal – Common Shareholder's Equity					2,682,780
Net Income			136,668		136,668
Other Comprehensive Income				2,231	2,231
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	260,458	1,475,496	1,133,748	(48,023)	2,821,679
Capital Contribution from Parent		100,000			100,000
Common Stock Dividends			(135,000)		(135,000)
Preferred Stock Dividends			(732)		(732)
Loss on Reacquired Preferred Stock		(1,770)			(1,770)
Capital Stock Expense		26	(27)		(1)
Subtotal – Common Shareholder's Equity					2,784,176
Net Income			162,758		162,758
Other Comprehensive Loss				(10,520)	(10,520)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	260,458	1,573,752	1,160,747	(58,543)	2,936,414
Common Stock Dividends			(170,000)		(170,000)
Subtotal – Common Shareholder's Equity					2,766,414
Net Income			257,503		257,503
Other Comprehensive Income				28,645	28,645
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2012	$ 260,458	$ 1,573,752	$ 1,248,250	$ (29,898)	$ 3,052,562

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2012 and 2011
(in thousands)

	December 31, 2012	December 31, 2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3,576	$ 2,317
Advances to Affiliates	23,024	22,008
Accounts Receivable:		
Customers	158,380	158,382
Affiliated Companies	96,213	136,194
Accrued Unbilled Revenues	70,825	68,427
Miscellaneous	1,344	5,505
Allowance for Uncollectible Accounts	(6,087)	(5,289)
Total Accounts Receivable	320,675	363,219
Fuel	185,813	143,931
Materials and Supplies	105,208	101,724
Risk Management Assets	30,960	39,645
Accrued Tax Benefits	50,032	7,715
Regulatory Asset for Under-Recovered Fuel Costs	74,906	41,105
Prepayments and Other Current Assets	18,690	21,745
TOTAL CURRENT ASSETS	812,884	743,409
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,632,665	5,194,967
Transmission	2,042,144	1,943,969
Distribution	2,991,898	2,845,405
Other Property, Plant and Equipment	373,327	357,326
Construction Work in Progress	266,247	565,841
Total Property, Plant and Equipment	11,306,281	10,907,508
Accumulated Depreciation and Amortization	3,196,639	2,994,016
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	8,109,642	7,913,492
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,435,704	1,481,193
Long-term Risk Management Assets	34,360	39,226
Deferred Charges and Other Noncurrent Assets	115,078	122,187
TOTAL OTHER NONCURRENT ASSETS	1,585,142	1,642,606
TOTAL ASSETS	$ 10,507,668	$ 10,299,507

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2012 and 2011

	December 31, 2012	December 31, 2011
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 173,965	$ 198,248
Accounts Payable:		
General	195,203	186,612
Affiliated Companies	137,088	137,376
Long-term Debt Due Within One Year – Nonaffiliated	574,679	594,525
Risk Management Liabilities	16,698	26,606
Customer Deposits	67,339	61,690
Deferred Income Taxes	11,715	14,255
Accrued Taxes	74,967	63,422
Accrued Interest	51,442	57,230
Other Current Liabilities	110,657	105,646
TOTAL CURRENT LIABILITIES	1,413,753	1,445,610
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,127,763	3,131,726
Long-term Risk Management Liabilities	18,476	12,923
Deferred Income Taxes	1,928,683	1,736,180
Regulatory Liabilities and Deferred Investment Tax Credits	607,680	576,792
Employee Benefits and Pension Obligations	204,207	302,182
Deferred Credits and Other Noncurrent Liabilities	154,544	157,680
TOTAL NONCURRENT LIABILITIES	6,041,353	5,917,483
TOTAL LIABILITIES	7,455,106	7,363,093
Rate Matters (Note 2)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260,458	260,458
Paid-in Capital	1,573,752	1,573,752
Retained Earnings	1,248,250	1,160,747
Accumulated Other Comprehensive Income (Loss)	(29,898)	(58,543)
TOTAL COMMON SHAREHOLDER'S EQUITY	3,052,562	2,936,414
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 10,507,668	$ 10,299,507

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	Years Ended December 31, 2012	2011	2010
OPERATING ACTIVITIES			
Net Income	$ 257,503	$ 162,758	$ 136,668
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	344,293	270,529	304,192
Deferred Income Taxes	138,460	107,565	144,413
Carrying Costs Income	(24,602)	(13,433)	(33,080)
Deferral of Storm Costs	(87,992)	(16,324)	(25,225)
Allowance for Equity Funds Used During Construction	(1,684)	(9,212)	(2,967)
Mark-to-Market of Risk Management Contracts	10,130	(26)	29,182
Pension Contributions to Qualified Plan Trust	(25,199)	(60,312)	(36,784)
Fuel Over/Under-Recovery, Net	96,774	(9,589)	(13,356)
Change in Regulatory Assets	(31,104)	(3,031)	63,700
Change in Other Noncurrent Assets	(21,724)	(2,402)	(15,668)
Change in Other Noncurrent Liabilities	24,206	10,392	1,757
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	42,161	59,352	(63,426)
Fuel, Materials and Supplies	(40,268)	80,191	116,530
Accounts Payable	12,547	(60,843)	(16,823)
Accrued Taxes, Net	(14,396)	71,610	76,881
Other Current Assets	3,706	15,570	1,287
Other Current Liabilities	7,234	3,933	(11,717)
Net Cash Flows from Operating Activities	690,045	606,728	655,564
INVESTING ACTIVITIES			
Construction Expenditures	(469,052)	(463,077)	(534,334)
Change in Advances to Affiliates, Net	(1,016)	(22,008)	-
Acquisitions of Assets	(1,183)	(302,512)	(2,485)
Other Investing Activities	8,392	15,096	12,871
Net Cash Flows Used for Investing Activities	(462,859)	(772,501)	(523,948)
FINANCING ACTIVITIES			
Capital Contribution from Parent	-	100,000	-
Issuance of Long-term Debt – Nonaffiliated	339,374	739,393	363,726
Change in Advances from Affiliates, Net	(24,283)	69,917	(101,215)
Retirement of Long-term Debt – Nonaffiliated	(364,875)	(579,672)	(200,019)
Retirement of Long-term Debt – Affiliated	-	-	(100,000)
Retirement of Cumulative Preferred Stock	-	(19,517)	(4)
Principal Payments for Capital Lease Obligations	(6,496)	(7,447)	(7,001)
Dividends Paid on Common Stock	(170,000)	(135,000)	(88,000)
Dividends Paid on Cumulative Preferred Stock	-	(732)	(799)
Other Financing Activities	353	197	641
Net Cash Flows from (Used for) Financing Activities	(225,927)	167,139	(132,671)
Net Increase (Decrease) in Cash and Cash Equivalents	1,259	1,366	(1,055)
Cash and Cash Equivalents at Beginning of Period	2,317	951	2,006
Cash and Cash Equivalents at End of Period	$ 3,576	$ 2,317	$ 951
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 200,383	$ 198,465	$ 202,884
Net Cash Paid (Received) for Income Taxes	31,418	(66,520)	(153,205)
Noncash Acquisitions Under Capital Leases	3,366	2,692	22,772
Government Grants Included in Accounts Receivable as of December 31,	-	1,048	1,049
Construction Expenditures Included in Current Liabilities as of December 31,	62,177	65,308	66,048

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to APCo's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to APCo. The footnotes begin on page 217.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Company Overview

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 584,000 retail customers in its service territory in northern and eastern Indiana and a portion of southwestern Michigan. I&M consolidates Blackhawk Coal Company and Price River Coal Company, its wholly-owned subsidiaries. I&M also consolidates DCC Fuel. I&M sells power at wholesale to municipalities and electric cooperatives. I&M's River Transportation Division provides barging services to affiliates and nonaffiliated companies. The revenues from barging represent the majority of other revenues.

The Interconnection Agreement 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. Members of the Interconnection Agreement are compensated for their costs of energy delivered and charged for energy received. The capacity reserve relationship of the Interconnection Agreement members changes as generating assets are added, retired or sold and relative peak demand changes. The Interconnection Agreement 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. The addition of APCo's Dresden Plant in January 2012 and removal of OPCo's Sporn Plant, Unit 5 in September 2011 changed the capacity reserve relationship of the 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 2010. The new Transmission Agreement will be phased in for retail rates over periods of up to four years, added KGPCo and WPCo as parties to the agreement and changed 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 a unit power agreement, 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 Interconnection Agreement. Another unit power agreement between AEGCo and KPCo provides for the sale of 390 MW of AEGCo's Rockport Plant capacity to KPCo through 2022. Under these agreements, I&M purchases 910 MW of AEGCo's 50% share of Rockport Plant capacity.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and 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 Interconnection 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 power purchase and sale activity pursuant to the SIA.

Regulatory Activity

Termination of Interconnection Agreement

Based upon the PUCO's approval of OPCo's corporate separation plan in October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generation assets from its distribution and transmission operations and transfer at net book value certain plants to APCo and KPCo. Additionally, the AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate their respective power supply resources. Under the PCA, APCo, I&M and KPCo would be individually responsible for planning their respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo, I&M and KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities. Intervenors have opposed several of these filings. The AEP East Companies have responded and continue to pursue approvals from the FERC. A decision from the FERC is expected in mid-2013.

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

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 $149 million net annual increase reflects an increase in base rates of $178 million offset by proposed corresponding reductions of $13 million to the off-system sales sharing rider, $9 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The request included an increase in depreciation rates that would result in an increase of approximately $25 million in annual depreciation expense. Included in the depreciation rates increase was a decrease in the average remaining life of Tanners Creek Plant to account for the acceleration of the retirement date of Tanners Creek Plant, Units 1-3. I&M filed rebuttal testimony in May 2012 which supported an increase of $170 million in base rates, excluding reductions to certain riders.

In February 2013, the IURC issued an order that granted an $85 million annual increase in base rates based upon a return on common equity of 10.2%, effective March 2013. The $85 million annual increase in base rates will be offset by corresponding reductions of $5 million to the off-system sales sharing rider, $11 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The IURC granted the requested increase in depreciation rates, modified the shareholder's portion of off-system sales margins to 50% below and above the $27 million imbedded in base rates, established a capacity tracker and established a major storm damage restoration reserve. See "2011 Indiana Base Rate Case" section of Note 2.

Michigan Capacity Rate

In April 2012, the FERC issued an order, effective October 2012, which sets I&M's capacity cost to be charged to alternative electric suppliers (AES) serving switching customers in I&M's Michigan service territory at $394/MW day unless a state compensation mechanism is approved by the MPSC. In May 2012, the MPSC issued an order to initiate a proceeding to establish a cost of service state compensation mechanism for the capacity rate to be charged to AES. In September 2012, the MPSC approved I&M's filed cost of service proposal with a minor adjustment recommended by the MPSC staff. Under Michigan law, switching is limited to 10% of I&M's Michigan load, which was achieved in June 2012, the second month of customer switching.

Rockport Plant Environmental Controls

I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit one unit at its Rockport Plant with environmental controls estimated to cost $1.4 billion to comply with new requirements. AEGCo and I&M jointly own Unit 1 and jointly lease Unit 2 of the Rockport Plant. I&M is also evaluating options related to the maturity of the lease for Rockport Plant, Unit 2 in 2022 and continues to investigate alternative compliance technologies for these units as part of its overall compliance strategy. As of December 31, 2012, I&M has incurred $36 million related to these environmental controls, including AFUDC. If I&M is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows. In February 2013, I&M filed a motion with the IURC to dismiss its request for approval of a CPCN for environmental controls after modification to the NSR consent decree. See the "Modification of the NSR Litigation Consent Decree" section of the Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries and the "Rockport Plant Environmental Controls" section of Note 2.

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 a fire on the electric generator. Repair of the property damage and replacement of the turbine rotors and other equipment cost approximately $400 million. In February 2013, management signed an agreement and received payment from NEIL, the insurer, to settle the remaining claims. The settlement did not have a material impact on net income, cash flows or financial condition. See "Cook Plant, Unit 1 Fire and Shutdown" section of Note 4.

Cook Plant Life Cycle Management Project

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its licensed life. The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. In Indiana, I&M requested recovery of certain project costs, including interest, through a new rider effective January 2013. In Michigan, I&M requested that the MPSC approve a Certificate of Need and authorize I&M to defer, on an interim basis, incremental depreciation and related property tax costs, including interest, along with study, analysis and development costs until the applicable LCM costs are included in I&M's base rates. As of December 31, 2012, I&M has incurred $176 million related to the LCM Project, including AFUDC. Several intervenors filed testimony in Indiana with various recommendations including caps on expenditures. The IURC held a hearing in January 2013.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project with total costs of $851 million (Michigan jurisdictional share is approximately 15%) for the period 2013 through 2018. The order provided that depreciation, property taxes and a return using the overall rate of return approved in I&M's last Michigan base rate case related to the 2013 through 2018 LCM Project costs can be deferred until these costs are included in rates. The order excluded from the CON $176 million of LCM costs spent prior to 2013 as $39 million was included in the determination of Michigan base rates, effective April 2012, and the remaining $137 million in CWIP will be requested in a future base rate case. The order also excluded $142 million of future LCM costs, which if incurred, will be requested in a future base rate case. Under Michigan law, the approved CON amount is eligible for a cost increase allowance of 10%, up to $85 million, of the approved project costs in the event project costs exceed the approved level of costs.

If I&M is not ultimately permitted to recover its LCM Project costs, it would reduce future net income and cash flows and impact financial condition. See "Cook Plant Life Cycle Management Project" section of Note 2.

Litigation and Environmental Issues

In the ordinary course of business, I&M is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 2 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 353 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2012	2011	2010
	(in millions of KWhs)		
Retail:			
Residential	5,771	5,997	6,083
Commercial	5,001	5,045	5,121
Industrial	7,556	7,523	7,445
Miscellaneous	75	73	72
Total Retail	18,403	18,638	18,721
Wholesale	9,782	9,249	7,839
Total KWhs	28,185	27,887	26,560

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2012	2011	2010
	(in degree days)		
Actual - Heating (a)	3,042	3,659	3,759
Normal - Heating (b)	3,772	3,766	3,774
Actual - Cooling (c)	1,098	1,075	1,165
Normal - Cooling (b)	861	848	832

(a) Eastern Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.

2012 Compared to 2011

Reconciliation of Year Ended December 31, 2011 to Year Ended December 31, 2012
Net Income
(in millions)

Year Ended December 31, 2011	$	150
Changes in Gross Margin:		
Retail Margins		(23)
FERC Municipals and Cooperatives		(8)
Off-system Sales		(12)
Transmission Revenues		1
Other Revenues		6
Total Change in Gross Margin		(36)
Changes in Expenses and Other:		
Other Operation and Maintenance		14
Depreciation and Amortization		(13)
Taxes Other Than Income Taxes		1
Other Income		(5)
Interest Expense		(5)
Total Change in Expenses and Other		(8)
Income Tax Expense		12
Year Ended December 31, 2012	$	118

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** decreased $23 million primarily due to the following:
  - A $54 million decrease in capacity settlements under the Interconnection Agreement, net of sharing with customers in Michigan. The decrease was primarily a result of a mild winter in 2012 and its impact on APCo's winter peak.
  - An $8 million decrease in weather-related usage primarily due to a 17% decrease in heating degree days.

  These decreases were partially offset by:
  - A $24 million increase in rate relief primarily due to higher PJM revenue, Michigan base rate increases and higher Indiana demand side management revenue.
  - A $14 million increase due to customer credits issued in 2011 for a settlement relating to the Cook Plant Unit 1 fire outage. This increase was offset by an increase in Other Operation and Maintenance expenses as discussed below.
- **Margins from FERC Municipals and Cooperatives** decreased $8 million primarily due to the following:
  - A $14 million decrease due to an annual rate adjustment to actual costs.

  This decrease was offset by:
  - A $6 million increase due to favorable fuel adjustments.
- **Margins from Off-system Sales** decreased $12 million primarily due to lower market prices, lower PJM capacity payments and reduced trading and marketing margins.
- **Other Revenues** increased $6 million primarily due to an unfavorable 2011 provision for refund of outage insurance proceeds.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $14 million primarily due to the following:
  - A $19 million decrease in nuclear generation maintenance expenses performed during the 2011 refueling outage.
  - A $17 million decrease due to an agreement reached to settle an insurance claim.
  - An $11 million decrease primarily due to maintenance outages at the Tanners Creek and Rockport plants during 2011.
  - A $7 million decrease in overhead line expenses.

  These decreases were partially offset by:
  - A $14 million increase in steam power expenses related to credits issued in 2011 associated with the Cook Plant Unit 1 fire outage. This increase was offset by a corresponding increase in Retail Margins as discussed above.
  - A $9 million increase due to an agreement to modify the NSR consent decree.
  - An $8 million increase associated with the favorable resolution of a contingency in 2011.
  - A $6 million increase due to expenses related to the 2012 sustainable cost reductions.
  - A $6 million increase due to the write off of an investment for possible storage of SNF.
- **Depreciation and Amortization** increased $13 million primarily due to higher depreciable base and higher depreciation rates reflecting a change in Tanners Creek Plant's estimated life as approved in the Michigan base case settlement effective April 2012. The majority of the increase in depreciation for Tanners Creek Plant's life is offset within Gross Margin.
- **Other Income** decreased $5 million primarily due to lower equity AFUDC related to nuclear fuel preparation for usage.
- **Interest Expense** increased $5 million primarily due to lower credits for AFUDC on borrowed funds related to nuclear fuel and higher tax-related interest.
- **Income Tax Expense** decreased $12 million primarily due to a decrease in pretax book income.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 353 for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and pension and other postretirement benefits.

See the "Accounting Pronouncements" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 353 for a discussion of accounting pronouncements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Indiana Michigan Power Company:

We have audited the accompanying consolidated balance sheets of Indiana Michigan Power Company and subsidiaries (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income (loss), changes in common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Indiana Michigan Power Company and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 26, 2013

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Indiana Michigan Power Company and subsidiaries (I&M) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. I&M's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of I&M's internal control over financial reporting as of December 31, 2012. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management's assessment, I&M's internal control over financial reporting was effective as of December 31, 2012.

This annual report does not include an attestation report of I&M's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit I&M to provide only management's report in this annual report.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	Years Ended December 31,		
	2012	**2011**	**2010**
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,810,069	$ 1,770,447	$ 1,735,338
Sales to AEP Affiliates	268,408	320,184	330,951
Other Revenues - Affiliated	117,052	109,053	114,070
Other Revenues - Nonaffiliated	4,582	15,086	15,368
TOTAL REVENUES	2,200,111	2,214,770	2,195,727
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	464,420	472,080	465,482
Purchased Electricity for Resale	117,860	121,375	128,369
Purchased Electricity from AEP Affiliates	386,404	353,484	327,335
Other Operation	583,865	540,595	560,346
Maintenance	172,562	229,883	222,406
Depreciation and Amortization	146,619	133,394	136,443
Taxes Other Than Income Taxes	80,687	82,303	80,431
TOTAL EXPENSES	1,952,417	1,933,114	1,920,812
OPERATING INCOME	247,694	281,656	274,915
Other Income (Expense):			
Interest Income	3,122	2,048	3,389
Allowance for Equity Funds Used During Construction	9,724	15,395	15,678
Interest Expense	(102,739)	(97,665)	(104,465)
INCOME BEFORE INCOME TAX EXPENSE	157,801	201,434	189,517
Income Tax Expense	39,344	51,760	63,426
NET INCOME	118,457	149,674	126,091
Preferred Stock Dividend Requirements Including Capital Stock Expense	-	626	339
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$ 118,457	$ 149,048	$ 125,752

The common stock of I&M is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	Years Ended December 31, 2012	2011	2010
Net Income	$ 118,457	$ 149,674	$ 126,091
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $2,590, $3,553 and $652 in 2012, 2011 and 2010, Respectively	(4,809)	(6,599)	1,211
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $598, $510 and $470 in 2012, 2011 and 2010, Respectively	1,113	948	873
Pension and OPEB Funded Status, Net of Tax of $1,634, $906 and $685 in 2012, 2011 and 2010, Respectively	3,034	(1,681)	(1,272)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(662)	(7,332)	812
TOTAL COMPREHENSIVE INCOME	$ 117,795	$ 142,342	$ 126,903

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$ 56,584	$ 981,292	$ 656,608	$ (21,701)	$ 1,672,783
Common Stock Dividends			(105,000)		(105,000)
Preferred Stock Dividends			(339)		(339)
Gain on Reacquired Preferred Stock		2			2
Subtotal – Common Shareholder's Equity					1,567,446
Net Income			126,091		126,091
Other Comprehensive Income				812	812
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	56,584	981,294	677,360	(20,889)	1,694,349
Common Stock Dividends			(75,000)		(75,000)
Preferred Stock Dividends			(313)		(313)
Loss on Reacquired Preferred Stock		(398)			(398)
Subtotal – Common Shareholder's Equity					1,618,638
Net Income			149,674		149,674
Other Comprehensive Loss				(7,332)	(7,332)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	56,584	980,896	751,721	(28,221)	1,760,980
Common Stock Dividends			(75,000)		(75,000)
Subtotal – Common Shareholder's Equity					1,685,980
Net Income			118,457		118,457
Other Comprehensive Loss				(662)	(662)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2012	$ 56,584	$ 980,896	$ 795,178	$ (28,883)	$ 1,803,775

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2012 and 2011
(in thousands)

	December 31, 2012	December 31, 2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,562	$ 1,020
Advances to Affiliates	116,977	95,714
Accounts Receivable:		
Customers	61,776	72,461
Affiliated Companies	79,886	90,980
Accrued Unbilled Revenues	11,218	14,780
Miscellaneous	12,260	22,685
Allowance for Uncollectible Accounts	(229)	(1,750)
Total Accounts Receivable	164,911	199,156
Fuel	53,406	52,979
Materials and Supplies	195,147	175,924
Risk Management Assets	26,974	32,152
Accrued Tax Benefits	20,547	38,425
Deferred Cook Plant Fire Costs	80,000	63,809
Prepayments and Other Current Assets	62,723	35,395
TOTAL CURRENT ASSETS	722,247	694,574
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,062,733	3,932,472
Transmission	1,278,236	1,224,786
Distribution	1,553,358	1,481,608
Other Property, Plant and Equipment (Including Nuclear Fuel and Coal Mining)	725,313	709,558
Construction Work in Progress	341,063	236,096
Total Property, Plant and Equipment	7,960,703	7,584,520
Accumulated Depreciation, Depletion and Amortization	3,232,135	3,179,920
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,728,568	4,404,600
OTHER NONCURRENT ASSETS		
Regulatory Assets	540,019	602,979
Spent Nuclear Fuel and Decommissioning Trusts	1,705,772	1,591,732
Long-term Risk Management Assets	23,569	29,362
Deferred Charges and Other Noncurrent Assets	111,364	69,309
TOTAL OTHER NONCURRENT ASSETS	2,380,724	2,293,382
TOTAL ASSETS	$ 7,831,539	$ 7,392,556

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2012 and 2011
(dollars in thousands)

	December 31, 2012	December 31, 2011
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 208,701	$ 113,063
Affiliated Companies	104,631	81,102
Long-term Debt Due Within One Year – Nonaffiliated (December 31, 2012 and 2011 Amounts Include $119,890 and $101,620, Respectively, Related to DCC Fuel)	203,953	279,075
Risk Management Liabilities	31,517	16,980
Customer Deposits	31,142	30,696
Accrued Taxes	67,675	65,233
Accrued Interest	26,859	27,798
Other Current Liabilities	122,053	117,879
TOTAL CURRENT LIABILITIES	796,531	731,826
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,853,713	1,778,600
Long-term Risk Management Liabilities	13,898	18,871
Deferred Income Taxes	1,019,160	925,712
Regulatory Liabilities and Deferred Investment Tax Credits	948,292	875,202
Asset Retirement Obligations	1,192,313	1,013,122
Deferred Credits and Other Noncurrent Liabilities	203,857	288,243
TOTAL NONCURRENT LIABILITIES	5,231,233	4,899,750
TOTAL LIABILITIES	6,027,764	5,631,576
Rate Matters (Note 2)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56,584	56,584
Paid-in Capital	980,896	980,896
Retained Earnings	795,178	751,721
Accumulated Other Comprehensive Income (Loss)	(28,883)	(28,221)
TOTAL COMMON SHAREHOLDER'S EQUITY	1,803,775	1,760,980
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 7,831,539	$ 7,392,556

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	Years Ended December 31, 2012	2011	2010
OPERATING ACTIVITIES			
Net Income	$ 118,457	$ 149,674	$ 126,091
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	146,619	133,394	136,443
Accretion of Asset Retirement Obligations	11,712	11,668	11,905
Deferred Income Taxes	53,067	141,015	63,947
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	13,899	13,244	(31,939)
Allowance for Equity Funds Used During Construction	(9,724)	(15,395)	(15,678)
Mark-to-Market of Risk Management Contracts	12,164	(1,590)	4,592
Amortization of Nuclear Fuel	135,905	136,707	139,438
Pension Contributions to Qualified Plan Trust	(22,285)	(52,588)	(71,681)
Fuel Over/Under-Recovery, Net	4,175	(13,885)	(12,589)
Change in Other Noncurrent Assets	(2,347)	(22,977)	(12,597)
Change in Other Noncurrent Liabilities	47,097	50,371	56,592
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	34,431	57,661	(85,072)
Fuel, Materials and Supplies	(19,321)	40,239	(16,564)
Accounts Payable	15,959	(52,175)	46,579
Accrued Taxes, Net	16,897	15,508	77,075
Cook Plant Fire Costs, Net	(8,465)	18,282	87,347
Other Current Assets	(2,039)	6,409	5,056
Other Current Liabilities	11,717	6,167	4,149
Net Cash Flows from Operating Activities	557,918	621,729	513,094
INVESTING ACTIVITIES			
Construction Expenditures	(317,284)	(301,242)	(333,238)
Change in Advances to Affiliates, Net	(21,263)	(95,714)	114,012
Purchases of Investment Securities	(1,045,422)	(1,166,690)	(1,414,473)
Sales of Investment Securities	987,550	1,110,909	1,361,813
Acquisitions of Nuclear Fuel	(106,714)	(105,703)	(90,903)
Other Investing Activities	29,324	47,169	17,105
Net Cash Flows Used for Investing Activities	(473,809)	(511,271)	(345,684)
FINANCING ACTIVITIES			
Issuance of Long-term Debt - Nonaffiliated	217,900	185,972	152,464
Change in Advances from Affiliates, Net	-	(42,769)	42,769
Retirement of Long-term Debt - Nonaffiliated	(220,212)	(160,645)	(202,011)
Retirement of Long-term Debt - Affiliated	-	-	(25,000)
Retirement of Cumulative Preferred Stock	-	(8,470)	(3)
Principal Payments for Capital Lease Obligations	(6,536)	(8,652)	(31,180)
Dividends Paid on Common Stock	(75,000)	(75,000)	(105,000)
Dividends Paid on Cumulative Preferred Stock	-	(313)	(339)
Other Financing Activities	281	78	472
Net Cash Flows Used for Financing Activities	(83,567)	(109,799)	(167,828)
Net Increase (Decrease) in Cash and Cash Equivalents	542	659	(418)
Cash and Cash Equivalents at Beginning of Period	1,020	361	779
Cash and Cash Equivalents at End of Period	$ 1,562	$ 1,020	$ 361
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 98,130	$ 95,124	$ 100,617
Net Cash Paid (Received) for Income Taxes	(21,196)	(96,452)	(71,268)
Noncash Acquisitions Under Capital Leases	6,243	3,454	10,000
Construction Expenditures Included in Current Liabilities as of December 31,	112,622	42,992	21,757
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	35,493	715	308
Noncash Increase in Long-term Debt Through the Fort Wayne Lease Settlement	-	26,802	-
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	30,332	-	-

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to I&M's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to I&M. The footnotes begin on page 217.

OHIO POWER COMPANY AND SUBSIDIARY

OHIO POWER COMPANY AND SUBSIDIARY
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Company Overview

As a public utility, OPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 1,459,000 retail customers in the northwestern, central, eastern and southern sections of Ohio. OPCo consolidates Conesville Coal Preparation Company, its wholly-owned subsidiary.

The Interconnection Agreement 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. Members of the Interconnection Agreement are compensated for their costs of energy delivered and charged for energy received. The capacity reserve relationship of the Interconnection Agreement members changes as generating assets are added, retired or sold and relative peak demand changes. The Interconnection Agreement 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. The addition of APCo's Dresden Plant in January 2012 and removal of OPCo's Sporn Plant, Unit 5 in September 2011 changed the capacity reserve relationship of the 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 2010. The new Transmission Agreement will be phased in for retail rates, added KGPCo and WPCo as parties to the agreement and changed the allocation method.

In 2007, OPCo and AEGCo entered into a 10-year unit power agreement for the entire output from the Lawrenceburg Plant with an option for an additional 2-year period. OPCo pays AEGCo for the capacity, depreciation, fuel, operation, maintenance and tax expenses. These payments are due regardless of whether the plant operates.

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 OPCo's behalf. OPCo 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 Interconnection Agreement and the SIA. OPCo 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 of 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.

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

Ohio Plant Impairments

In October 2012, management filed applications with the FERC proposing to terminate the Interconnection Agreement and complete the corporate separation of OPCo's generation assets. Based on the intention to terminate the Interconnection Agreement, management performed an evaluation of the recoverability of generation assets using generating unit specific estimated future cash flows and concluded that OPCo had a material impairment of certain generation assets. In the fourth quarter of 2012, OPCo recorded a pretax impairment of $287 million ($185 million, net of tax) in Asset Impairments and Other Related Charges on the statement of income related to Beckjord Plant Unit 6, Conesville Plant Unit 3, Kammer Plant Units 1-3, Muskingum River Plant Units 1-4, Sporn Plant Units 2 and 4 and Picway Plant Unit 5 generating units and related material and supplies inventory.

Ohio Customer Choice

In OPCo's service territory, various CRES providers are targeting retail customers by offering alternative generation service. As a result, OPCo lost approximately $235 million of gross margin in 2012 as compared to 2011. This reduction in gross margin is partially offset by (a) collection of capacity revenues from CRES providers, (b) off-system sales, (c) deferral of unrecovered capacity costs and (d) Retail Stability Rider collections. As of December 31, 2012, based upon an average annual load, approximately 51% of OPCo's load had switched to CRES providers.

Regulatory Activity

June 2012 – May 2015 Ohio ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP through May 2015. The ESP allowed the continuation of the fuel adjustment clause, adopted a 12% earnings threshold for the SEET and established a non-bypassable Distribution Investment Rider (DIR) effective September 2012 through May 2015 to recover, with certain caps, post-August 2010 distribution investment. The DIR is capped at $86 million in 2012, $104 million in 2013, $124 million in 2014 and $52 million for the period January through May 2015, for a total of $366 million. The ESP also maintained recovery of several previous ESP riders and required OPCo to contribute $2 million per year during the ESP to the Ohio Growth Fund. In addition, the PUCO approved a storm damage recovery mechanism.

As part of the ESP decision, the PUCO ordered OPCo to conduct an energy-only auction for 10% of the SSO load with delivery beginning six months after the receipt of final orders in both the ESP and corporate separation cases and extending through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 50% of the SSO load with delivery beginning June 2014 through May 2015 and for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. OPCo will conduct energy and capacity auctions for its entire SSO load for delivery starting in June 2015.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The RPM price is approximately $20/MW day through May 2013. As part of the August 2012 PUCO ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is intended to provide approximately $500 million over the ESP period and will be collected from customers at $3.50/MWh through May 2014 and $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the deferred capacity costs. As of December 31, 2012, OPCo recorded $66 million of incurred deferred capacity costs, including debt carrying costs, in Regulatory Assets on the balance sheet. The capacity order, including collection of capacity costs, has been appealed to the Supreme Court of Ohio.

In January 2013, the PUCO issued its Order on Rehearing for the ESP which generally upheld its August 2012 order including the implementation of the RSR. The PUCO clarified that a final reconciliation of revenues and costs would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket. If OPCo is ultimately not permitted to fully collect its deferred capacity costs and ESP rates, including the RSR, it would reduce future net income and cash flows and impact financial condition. See "Ohio Electric Security Plan Filing" section of Note 2.

Corporate Separation, Plant Transfers and Termination of Interconnection Agreement

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo's generation assets including the transfer of OPCo's generation assets at net book value to AEPGenCo. AEPGenCo will also assume the associated generation liabilities. In December 2012, the PUCO granted the IEU and the Ohio Consumers' Counsel requests for rehearing for the purpose of further consideration and those requests remain pending.

Also in October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generation assets from its distribution and transmission operations. The filings requested approval to transfer at net book value approximately 9,200 MW of OPCo-owned generation assets to AEPGenCo. The AEP East Companies also requested FERC approval to transfer at net book value OPCo's current two-thirds ownership (867 MW) in Amos Plant, Unit 3 to APCo and transfer at net book value OPCo's Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each). Additionally, the AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate their respective power supply resources. Under the PCA, APCo, I&M and KPCo would be individually responsible for planning their respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo, I&M and KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities. Intervenors have opposed several of these filings. The AEP East Companies have responded and continue to pursue approvals from the FERC. A decision from the FERC is expected in mid-2013.

Significantly Excessive Earnings Test

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. In the fourth quarter of 2012, the Supreme Court of Ohio upheld the PUCO decision on the 2009 SEET filing. Subsequent testimony and legal briefs from intervenors recommended refunds of a portion of 2010 earnings. OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO ordered SEET refund. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo and in 2012 for OPCo. See "Ohio Electric Security Plan Filing" section of Note 2.

Securitization of Regulatory Asset

In August 2012, OPCo filed an application with the PUCO requesting securitization of the Deferred Asset Recovery Rider (DARR) balance. As of December 31, 2012, OPCo's DARR balance was $287 million, including $135 million of unrecognized equity carrying costs. Currently, the DARR is being recovered through 2018 by a non-bypassable rider. If the application is approved and the securitization bonds are issued, the DARR will cease and will be replaced by the Deferred Asset Phase-in Rider, which will recover the securitized asset over seven years.

Litigation and Environmental Issues

In the ordinary course of business, OPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 2 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 353 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2012	**2011**	**2010**
	(in millions of KWhs)		
Retail:			
Residential	14,485	15,082	15,386
Commercial	14,176	14,269	14,454
Industrial	18,122	18,946	17,455
Miscellaneous	120	123	129
Total Retail	46,903	48,420	47,424
Wholesale	13,221	12,229	8,466
Total KWhs	60,124	60,649	55,890

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2012	**2011**	**2010**
	(in degree days)		
Actual - Heating (a)	2,610	3,107	3,488
Normal - Heating (b)	3,276	3,266	3,267
Actual - Cooling (c)	1,248	1,112	1,189
Normal - Cooling (b)	948	936	921

(a) Eastern Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.

2012 Compared to 2011

Reconciliation of Year Ended December 31, 2011 to Year Ended December 31, 2012
Net Income
(in millions)

Year Ended December 31, 2011	$ 465
Changes in Gross Margin:	
Retail Margins	(201)
Off-system Sales	5
Transmission Revenues	43
Other Revenues	6
Total Change in Gross Margin	(147)
Changes in Expenses and Other:	
Other Operation and Maintenance	159
Asset Impairments and Other Related Charges	(197)
Depreciation and Amortization	34
Taxes Other Than Income Taxes	(6)
Carrying Costs Income	(36)
Other Income	(6)
Interest Expense	9
Total Change in Expenses and Other	(43)
Income Tax Expense	69
Year Ended December 31, 2012	$ 344

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** decreased $201 million primarily due to the following:
  - A $289 million decrease attributable to customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.
  - A $165 million decrease in capacity settlement revenues under the Interconnection Agreement. This decrease was primarily as a result of a mild winter in 2012 and its impact on APCo's winter peak, APCo's completion of the Dresden Plant in January 2012 and the removal of Sporn Plant Unit 5 from the Interconnection Agreement in September 2011.
  - An $85 million net decrease in regulated revenue due to the elimination of POLR charges, effective June 2011, partially offset by the 2011 provision for refund of POLR charges. The refund provision was recorded as a result of the October 2011 PUCO remand order.

  These decreases were partially offset by:
  - A $177 million increase in revenues associated with the Retail Stability Rider, Deferred Asset Recovery Rider and Distribution Investment Recovery Rider. A portion of these increases have corresponding increases in other expense items below.
  - A $35 million increase due to a decrease in consumable and allowance expenses not recovered in the FAC.
  - A $35 million increase due to the 2012 partial reversal of a 2011 fuel provision based on an April 2012 PUCO order related to the 2009 FAC audit.
  - A $33 million decrease in recoverable PJM expenses.
- **Margins from Off-system Sales** increased $5 million primarily due to higher CRES capacity revenues, partially offset by lower market prices, lower PJM capacity payments and reduced trading and marketing margins.
- **Transmission Revenues** increased $43 million primarily due to increased transmission revenues related to customers who have switched to alternative CRES providers. The increase in transmission revenues related to CRES providers offsets the lost transmission revenues included in Retail Margins above.

- **Other Revenues** increased $6 million primarily due to increased revenues for coal transit from OPCo's Cook Coal Terminal. This increase in revenues was offset by a corresponding increase in Other Operation and Maintenance as discussed below.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $159 million primarily due to:
  - An $88 million decrease in plant maintenance expenses at various plants.
  - A $70 million decrease related to the 2011 recording and subsequent 2012 reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of the Ohio modified stipulation.
  - An $11 million decrease in transmission expenses related to the Transmission Agreement as a result of decreased load and customer switching.
  - A $10 million decrease due to the deferral of capacity-related costs as a result of the PUCO's July 2012 approval of the capacity deferral mechanism.
  - A $9 million decrease due to the 2011 asset retirement obligation write-offs for fully depreciated units at the Sporn, Conesville and Tidd plants.
  - A $6 million decrease due to the 2011 write-off of allocated Front-End Engineering and Design study costs related to the Mountaineer Carbon Capture Project.
  - A $3 million decrease as a result of a legal proceeding in 2011.

  These decreases were partially offset by:
  - A $13 million increase due to expenses related to the 2012 sustainable cost reductions.
  - An $11 million gain from the sale of land in January 2011.
  - An $8 million increase in advertising expenses.
  - An $8 million increase in expenses related to Cook Coal Terminal. This increase in expenses was offset by a corresponding increase in Other Revenues as discussed above.
- **Asset Impairments and Other Related Charges** increased $197 million due to the following:
  - A 2012 impairment of $287 million for certain Ohio generation plants which includes $13 million of related materials and supplies inventory.

  This increase was offset by:
  - A 2011 plant impairment of $48 million for Sporn Plant Unit 5.
  - A 2011 plant impairment of $42 million for the FGD project at Muskingum River Plant Unit 5.
- **Depreciation and Amortization** decreased $34 million primarily due to:
  - A $39 million decrease due to an amortization adjustment approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012.
  - A $28 million decrease due to the deferral of capacity-related depreciation costs as a result of the PUCO's July 2012 approval of the capacity rate.
  - A $23 million decrease due to the amortization of carrying costs on deferred fuel as a result of the October 2011 PUCO remand order which allowed the POLR refund to be applied against any deferred fuel balances. The equity amortization was offset by amounts recognized in Carrying Costs Income as discussed below.
  - A $13 million decrease in depreciation due to the 2011 plant impairment of Sporn Plant Unit 5.

  These decreases were partially offset by:
  - A $58 million increase due to shortened depreciable lives for certain generating plants effective December 2011. The book value of these plants was fully impaired in November 2012.
  - An $11 million increase in amortization of the Deferred Asset Recovery Rider assets as approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012. This increase in amortization is offset within Gross Margin.
- **Taxes Other Than Income Taxes** increased $6 million primarily due to increased property taxes as a result of increased capital investments and increased tax rates.
- **Carrying Costs Income** decreased $36 million primarily due to the following:
  - A $12 million decrease due to the recognition of carrying costs income on deferred fuel as a result of the October 2011 PUCO remand order which allowed the POLR refund to be applied against any deferred fuel balances. The carrying costs income was offset by amounts in Depreciation and Amortization discussed above.

  - An $11 million decrease in FAC deferrals due to the implementation of the Phase-In Recovery Rider in 2012. A portion of the deferred charges are recorded in Retail Margins above.
  - A $6 million decrease due to line extension carrying charges recorded in 2011.
  - A $5 million reduction in debt carrying charges associated with the 2008 coal contract settlement for the period January 2009 through March 2012 as ordered by the PUCO in April 2012 related to the 2009 FAC audit.
- **Interest Expense** decreased $9 million primarily as a result of a net increase in capitalized interest.
- **Income Tax Expense** decreased $69 million primarily due to a decrease in pretax book income.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 353 for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and pension and other postretirement benefits.

See the "Accounting Pronouncements" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 353 for a discussion of accounting pronouncements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Ohio Power Company:

We have audited the accompanying consolidated balance sheets of Ohio Power Company and subsidiary (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income (loss), changes in common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Ohio Power Company and subsidiary as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 26, 2013

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Ohio Power Company and Subsidiary (OPCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. OPCo's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of OPCo's internal control over financial reporting as of December 31, 2012. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management's assessment, OPCo's internal control over financial reporting was effective as of December 31, 2012.

This annual report does not include an attestation report of OPCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit OPCo to provide only management's report in this annual report.

OHIO POWER COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	Years Ended December 31,		
	2012	**2011**	**2010**
REVENUES			
Electric Generation, Transmission and Distribution	$ 4,022,116	$ 4,406,814	$ 4,222,461
Sales to AEP Affiliates	847,294	977,999	991,285
Other Revenues - Affiliated	39,401	27,903	21,069
Other Revenues - Nonaffiliated	19,385	18,395	20,301
TOTAL REVENUES	4,928,196	5,431,111	5,255,116
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	1,471,316	1,597,410	1,488,474
Purchased Electricity for Resale	205,845	300,653	286,835
Purchased Electricity from AEP Affiliates	380,706	515,613	386,618
Other Operation	669,981	754,109	795,129
Maintenance	319,324	393,943	346,745
Asset Impairments and Other Related Charges	287,031	89,824	-
Depreciation and Amortization	511,070	545,376	513,168
Taxes Other Than Income Taxes	405,976	399,479	393,537
TOTAL EXPENSES	4,251,249	4,596,407	4,210,506
OPERATING INCOME	676,947	834,704	1,044,610
Other Income (Expense):			
Interest Income	3,536	7,069	2,567
Carrying Costs Income	16,942	53,345	31,796
Allowance for Equity Funds Used During Construction	3,492	5,549	5,949
Interest Expense	(213,100)	(221,977)	(242,000)
INCOME BEFORE INCOME TAX EXPENSE	487,817	678,690	842,922
Income Tax Expense	144,283	213,697	301,306
NET INCOME	343,534	464,993	541,616
Preferred Stock Dividend Requirements Including Capital Stock Expense	-	1,259	881
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$ 343,534	$ 463,734	$ 540,735

The common stock of OPCo is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

OHIO POWER COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	Years Ended December 31,		
	2012	2011	2010
Net Income	$ 343,534	$ 464,993	$ 541,616
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $282, $1,477 and $529 in 2012, 2011 and 2010, Respectively	(523)	(2,743)	(981)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $6,979, $5,894 and $5,128 in 2012, 2011 and 2010, Respectively	12,961	10,946	9,522
Pension and OPEB Funded Status, Net of Tax of $10,533, $13,876 and $10,901 in 2012, 2011 and 2010, Respectively	19,559	(25,770)	(20,245)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	31,997	(17,567)	(11,704)
TOTAL COMPREHENSIVE INCOME	$ 375,531	$ 447,426	$ 529,912

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

OHIO POWER COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$ 321,201	$ 1,744,838	$ 2,696,942	$ (168,451)	$ 4,594,530
Common Stock Dividends			(469,075)		(469,075)
Preferred Stock Dividends			(732)		(732)
Gain on Reacquired Preferred Stock		4			4
Capital Stock Expense		149	(149)		-
Subtotal – Common Shareholder's Equity					4,124,727
Net Income			541,616		541,616
Other Comprehensive Loss				(11,704)	(11,704)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	321,201	1,744,991	2,768,602	(180,155)	4,654,639
Common Stock Dividends			(650,000)		(650,000)
Preferred Stock Dividends			(671)		(671)
Loss on Reacquired Preferred Stock		(1,216)			(1,216)
Capital Stock Expense		324	(324)		-
Subtotal – Common Shareholder's Equity					4,002,752
Net Income			464,993		464,993
Other Comprehensive Loss				(17,567)	(17,567)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	321,201	1,744,099	2,582,600	(197,722)	4,450,178
Common Stock Dividends			(300,000)		(300,000)
Subtotal – Common Shareholder's Equity					4,150,178
Net Income			343,534		343,534
Other Comprehensive Income				31,997	31,997
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2012	$ 321,201	$ 1,744,099	$ 2,626,134	$ (165,725)	$ 4,525,709

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

OHIO POWER COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2012 and 2011
(in thousands)

	December 31, 2012	December 31, 2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3,640	$ 2,095
Advances to Affiliates	116,422	219,458
Accounts Receivable:		
Customers	135,954	146,432
Affiliated Companies	176,590	162,830
Accrued Unbilled Revenues	57,887	19,012
Miscellaneous	9,327	16,994
Allowance for Uncollectible Accounts	(129)	(3,563)
Total Accounts Receivable	379,629	341,705
Fuel	328,840	262,886
Materials and Supplies	186,269	201,325
Risk Management Assets	44,313	54,293
Accrued Tax Benefits	17,785	11,975
Prepayments and Other Current Assets	26,807	41,560
TOTAL CURRENT ASSETS	1,103,705	1,135,297
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	8,673,296	9,502,614
Transmission	2,013,737	1,948,329
Distribution	3,722,745	3,545,574
Other Property, Plant and Equipment	571,154	546,642
Construction Work in Progress	354,497	354,465
Total Property, Plant and Equipment	15,335,429	15,897,624
Accumulated Depreciation and Amortization	5,242,805	5,742,561
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	10,092,624	10,155,063
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,420,966	1,370,504
Long-term Risk Management Assets	48,288	53,614
Deferred Charges and Other Noncurrent Assets	320,026	309,775
TOTAL OTHER NONCURRENT ASSETS	1,789,280	1,733,893
TOTAL ASSETS	$ 12,985,609	$ 13,024,253

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

OHIO POWER COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2012 and 2011

	December 31, 2012	December 31, 2011
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 276,220	$ 293,730
Affiliated Companies	153,222	183,898
Long-term Debt Due Within One Year – Nonaffiliated	856,000	244,500
Risk Management Liabilities	24,155	36,561
Accrued Taxes	467,309	450,570
Accrued Interest	63,560	66,441
Other Current Liabilities	263,638	238,275
TOTAL CURRENT LIABILITIES	2,104,104	1,513,975
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,804,440	3,609,648
Long-term Debt – Affiliated	200,000	200,000
Long-term Risk Management Liabilities	25,965	17,890
Deferred Income Taxes	2,345,850	2,245,380
Regulatory Liabilities and Deferred Investment Tax Credits	451,071	301,124
Employee Benefits and Pension Obligations	178,620	335,029
Deferred Credits and Other Noncurrent Liabilities	349,850	351,029
TOTAL NONCURRENT LIABILITIES	6,355,796	7,060,100
TOTAL LIABILITIES	8,459,900	8,574,075
Rate Matters (Note 2)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321,201	321,201
Paid-in Capital	1,744,099	1,744,099
Retained Earnings	2,626,134	2,582,600
Accumulated Other Comprehensive Income (Loss)	(165,725)	(197,722)
TOTAL COMMON SHAREHOLDER'S EQUITY	4,525,709	4,450,178
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 12,985,609	$ 13,024,253

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

OHIO POWER COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	Years Ended December 31, 2012	2011	2010
OPERATING ACTIVITIES			
Net Income	$ 343,534	$ 464,993	$ 541,616
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	511,070	545,376	513,168
Deferred Income Taxes	45,685	119,184	292,831
Asset Impairments and Other Related Charges	287,031	89,824	-
Carrying Costs Income	(16,942)	(53,345)	(31,796)
Deferral of Storm Costs	(53,453)	(8,375)	-
Allowance for Equity Funds Used During Construction	(3,492)	(5,549)	(5,949)
Mark-to-Market of Risk Management Contracts	12,143	(3,695)	25,251
Pension Contributions to Qualified Plan Trust	(43,189)	(127,884)	(58,639)
Property Taxes	(3,849)	(5,722)	(19,324)
Fuel Over/Under-Recovery, Net	10,598	(727)	(131,850)
Change in Other Noncurrent Assets	(68,924)	(64,867)	3,797
Change in Other Noncurrent Liabilities	(27,039)	85,173	(17,079)
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(37,787)	116,197	(126,071)
Fuel, Materials and Supplies	(54,945)	79,787	66,700
Accounts Payable	(63,450)	(17,059)	72,694
Accrued Taxes, Net	41,475	36,466	131,441
Other Current Assets	9,977	7,789	924
Other Current Liabilities	17,669	(15,821)	53,985
Net Cash Flows from Operating Activities	906,112	1,241,745	1,311,699
INVESTING ACTIVITIES			
Construction Expenditures	(517,744)	(454,873)	(504,702)
Change in Advances to Affiliates, Net	103,036	(64,756)	283,650
Acquisitions of Assets	(2,915)	(2,229)	(5,801)
Proceeds from Sales of Assets	7,320	47,463	14,382
Other Investing Activities	10,014	29,014	26,400
Net Cash Flows Used for Investing Activities	(400,289)	(445,381)	(186,071)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	-	49,748	351,824
Change in Advances from Affiliates, Net	-	-	(24,202)
Retirement of Long-term Debt – Nonaffiliated	(194,500)	(165,000)	(868,580)
Retirement of Long-term Debt – Affiliated	-	-	(100,000)
Retirement of Cumulative Preferred Stock	-	(17,831)	(7)
Principal Payments for Capital Lease Obligations	(10,072)	(11,854)	(11,617)
Dividends Paid on Common Stock	(300,000)	(650,000)	(469,075)
Dividends Paid on Cumulative Preferred Stock	-	(671)	(732)
Other Financing Activities	294	390	(5,370)
Net Cash Flows Used for Financing Activities	(504,278)	(795,218)	(1,127,759)
Net Increase (Decrease) in Cash and Cash Equivalents	1,545	1,146	(2,131)
Cash and Cash Equivalents at Beginning of Period	2,095	949	3,080
Cash and Cash Equivalents at End of Period	$ 3,640	$ 2,095	$ 949
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 212,753	$ 226,711	$ 239,984
Net Cash Paid (Received) for Income Taxes	69,771	81,740	(78,268)
Noncash Acquisitions Under Capital Leases	8,602	5,766	33,369
Government Grants Included in Accounts Receivable as of December 31,	660	1,383	9,260
Construction Expenditures Included in Current Liabilities as of December 31,	84,321	61,428	31,939

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

OHIO POWER COMPANY AND SUBSIDIARY
INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to OPCo's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to OPCo. The footnotes begin on page 217.

PUBLIC SERVICE COMPANY OF OKLAHOMA

PUBLIC SERVICE COMPANY OF OKLAHOMA
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Company Overview

As a public utility, PSO engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 535,000 retail customers in its service territory in eastern and southwestern Oklahoma. PSO sells electric power at wholesale to other utilities, municipalities and electric cooperatives.

PSO, as a party to the CSW Operating Agreement, is compensated for energy delivered to the other member based upon the delivering member's incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. PSO and SWEPCo share the revenues and costs of sales to neighboring utilities and power marketers made by AEPSC on their behalf based upon the relative magnitude of the energy each company provides to make such sales. PSO shares off-system sales margins, if positive on an annual basis, with its customers.

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 PSO's behalf. PSO shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the AEP East Companies and SWEPCo. Power and gas risk management activities are allocated based on the CSW Operating Agreement and the SIA. PSO 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.

PSO is jointly and severally liable for activity conducted by AEPSC on behalf of PSO and SWEPCo related to power purchase and sale activity pursuant to the SIA.

Regulatory Activity

Oklahoma Environmental Compliance Plan

In September 2012, PSO filed an environmental compliance plan with the OCC reflecting the retirement of Northeastern Station (NES) Unit 4 in 2016 and additional environmental controls on NES Unit 3 to continue operations through 2026. The plan requested approval for (a) cost recovery through base rates by 2026 of an estimated $256 million of new environmental investment that will be incurred prior to 2016 at NES Unit 3, (b) cost recovery through 2026 of NES Units 3 and 4 net book value (combined net book value of the two units is $234 million as of December 31, 2012), (c) cost recovery through base rates of an estimated $83 million of new investment incurred through 2016 at various gas units and (d) a new 15-year purchase power agreement (PPA) with Calpine Oneta Power, effective in 2016, with cost recovery through a rider, including an annual earnings component of $3 million. Although the environmental compliance plan does not seek to put any new costs into rates at this time, PSO anticipates seeking cost recovery when filing its next base rate case, which is expected to occur no later than 2014. In January 2013, several parties filed testimony with various recommendations. A hearing is scheduled for April 2013. See "Oklahoma Environmental Compliance Plan" section of Note 2.

Litigation and Environmental Issues

In the ordinary course of business, PSO is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 2 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 353 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2012	**2011**	**2010**
	(in millions of KWhs)		
Retail:			
Residential	6,393	6,741	6,595
Commercial	5,178	5,190	5,136
Industrial	5,066	4,956	4,921
Miscellaneous	1,326	1,310	1,265
Total Retail	17,963	18,197	17,917
Wholesale	1,492	1,113	1,190
Total KWhs	19,455	19,310	19,107

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2012	**2011**	**2010**
	(in degree days)		
Actual - Heating (a)	1,271	1,879	1,993
Normal - Heating (b)	1,803	1,796	1,784
Actual - Cooling (c)	2,663	2,788	2,380
Normal - Cooling (b)	2,119	2,102	2,095

(a) Western Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Western Region cooling degree days are calculated on a 65 degree temperature base.

2012 Compared to 2011

Reconciliation of Year Ended December 31, 2011 to Year Ended December 31, 2012
Net Income
(in millions)

Year Ended December 31, 2011	$	125
Changes in Gross Margin:		
Retail Margins (a)		7
Off-system Sales		(1)
Transmission Revenues		(1)
Total Change in Gross Margin		5
Changes in Expenses and Other:		
Other Operation and Maintenance		(14)
Depreciation and Amortization		1
Taxes Other Than Income Taxes		(2)
Other Income		(1)
Interest Expense		(1)
Total Change in Expenses and Other		(17)
Income Tax Expense		1
Year Ended December 31, 2012	$	114

(a) Includes firm wholesale sales to municipals and cooperatives.

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** increased $7 million primarily due to the following:
  - A $13 million increase primarily due to revenue increases from rate riders. This increase in retail margins has corresponding increases to riders/trackers recognized in other expense items below.
  - A $7 million increase primarily due to higher commercial non-weather related usage.

  These increases were partially offset by:
  - A $12 million decrease in weather-related usage primarily due to a 4% decrease in cooling degree days and a 32% decrease in heating degree days.

Expenses and Other changed between years as follows:

- **Other Operation and Maintenance** expenses increased $14 million primarily due to the following:
  - A $16 million increase in transmission expenses primarily due to increased SPP transmission services.
  - A $4 million increase due to expenses related to the 2012 sustainable cost reductions.
  - A $4 million increase in plant maintenance expenses due to the deferral of generation maintenance expenses in 2011 as a result of PSO's base rate case.

  These increases were partially offset by:
  - A $6 million decrease in general and administrative expenses.
  - A $3 million decrease in demand side management programs.
  - A $2 million decrease in distribution expenses primarily due to decreased overhead line expenses.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 353 for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and pension and other postretirement benefits.

See the "Accounting Pronouncements" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 353 for a discussion of accounting pronouncements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Public Service Company of Oklahoma:

We have audited the accompanying balance sheets of Public Service Company of Oklahoma (the "Company") as of December 31, 2012 and 2011, and the related statements of income, comprehensive income (loss), changes in common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Public Service Company of Oklahoma as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 26, 2013

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Public Service Company of Oklahoma (PSO) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. PSO's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of PSO's internal control over financial reporting as of December 31, 2012. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management's assessment, PSO's internal control over financial reporting was effective as of December 31, 2012.

This annual report does not include an attestation report of PSO's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit PSO to provide only management's report in this annual report.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	Years Ended December 31,		
	2012	2011	2010
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,206,583	$ 1,345,551	$ 1,246,916
Sales to AEP Affiliates	22,603	14,192	23,528
Other Revenues	3,752	3,645	3,218
TOTAL REVENUES	1,232,938	1,363,388	1,273,662
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	310,296	465,546	373,317
Purchased Electricity for Resale	208,676	163,550	187,106
Purchased Electricity from AEP Affiliates	24,378	50,092	46,013
Other Operation	213,195	201,247	222,396
Maintenance	106,835	104,732	115,788
Depreciation and Amortization	95,180	95,915	104,929
Taxes Other Than Income Taxes	43,428	41,295	42,121
TOTAL EXPENSES	1,001,988	1,122,377	1,091,670
OPERATING INCOME	230,950	241,011	181,992
Other Income (Expense):			
Interest Income	1,308	596	308
Carrying Costs Income	1,856	4,033	3,145
Allowance for Equity Funds Used During Construction	2,007	1,317	804
Interest Expense	(55,286)	(54,700)	(63,362)
INCOME BEFORE INCOME TAX EXPENSE	180,835	192,257	122,887
Income Tax Expense	66,694	67,629	50,100
NET INCOME	114,141	124,628	72,787
Preferred Stock Dividend Requirements Including Capital Stock Expense	-	434	200
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$ 114,141	$ 124,194	$ 72,587

The common stock of PSO is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	Years Ended December 31,		
	2012	**2011**	**2010**
Net Income	$ 114,141	$ 124,628	$ 72,787
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $360, $724 and $4,896 in 2012, 2011 and 2010, Respectively	(668)	(1,345)	9,093
TOTAL COMPREHENSIVE INCOME	$ 113,473	$ 123,283	$ 81,880

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$ 157,230	$ 364,231	$ 290,880	$ (599)	$ 811,742
Common Stock Dividends			(51,026)		(51,026)
Preferred Stock Dividends			(200)		(200)
Gain on Reacquired Preferred Stock		76			76
Subtotal – Common Shareholder's Equity					760,592
Net Income			72,787		72,787
Other Comprehensive Income				9,093	9,093
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	157,230	364,307	312,441	8,494	842,472
Common Stock Dividends			(72,500)		(72,500)
Preferred Stock Dividends			(180)		(180)
Loss on Reacquired Preferred Stock		(270)			(270)
Subtotal – Common Shareholder's Equity					769,522
Net Income			124,628		124,628
Other Comprehensive Loss				(1,345)	(1,345)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	157,230	364,037	364,389	7,149	892,805
Common Stock Dividends			(90,000)		(90,000)
Subtotal – Common Shareholder's Equity					802,805
Net Income			114,141		114,141
Other Comprehensive Loss				(668)	(668)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2012	$ 157,230	$ 364,037	$ 388,530	$ 6,481	$ 916,278

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
ASSETS
December 31, 2012 and 2011
(in thousands)

	December 31, 2012	December 31, 2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,367	$ 1,413
Advances to Affiliates	10,558	39,876
Accounts Receivable:		
Customers	31,047	39,977
Affiliated Companies	24,751	23,079
Miscellaneous	6,216	8,993
Allowance for Uncollectible Accounts	(872)	(777)
Total Accounts Receivable	61,142	71,272
Fuel	22,085	20,854
Materials and Supplies	52,183	50,347
Risk Management Assets	509	565
Deferred Income Tax Benefits	7,183	7,013
Accrued Tax Benefits	11,812	6,733
Regulatory Asset for Under-Recovered Fuel Costs	-	4,313
Prepayments and Other Current Assets	7,633	6,440
TOTAL CURRENT ASSETS	174,472	208,826
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,346,530	1,317,948
Transmission	706,917	692,644
Distribution	1,859,557	1,762,110
Other Property, Plant and Equipment	210,549	214,626
Construction Work in Progress	95,170	70,371
Total Property, Plant and Equipment	4,218,723	4,057,699
Accumulated Depreciation and Amortization	1,278,941	1,266,816
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	2,939,782	2,790,883
OTHER NONCURRENT ASSETS		
Regulatory Assets	202,328	266,545
Long-term Risk Management Assets	31	314
Deferred Charges and Other Noncurrent Assets	8,560	13,536
TOTAL OTHER NONCURRENT ASSETS	210,919	280,395
TOTAL ASSETS	$ 3,325,173	$ 3,280,104

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2012 and 2011

	December 31, 2012	December 31, 2011
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 87,050	$ 76,607
Affiliated Companies	36,189	45,029
Long-term Debt Due Within One Year – Nonaffiliated	764	311
Risk Management Liabilities	5,848	1,280
Customer Deposits	46,533	47,493
Accrued Taxes	28,024	21,660
Accrued Interest	12,654	12,637
Regulatory Liability for Over-Recovered Fuel Costs	7,945	-
Other Current Liabilities	50,684	43,586
TOTAL CURRENT LIABILITIES	275,691	248,603
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	949,107	947,053
Long-term Risk Management Liabilities	31	1,330
Deferred Income Taxes	740,676	726,463
Regulatory Liabilities and Deferred Investment Tax Credits	344,817	334,812
Employee Benefits and Pension Obligations	34,906	84,548
Deferred Credits and Other Noncurrent Liabilities	63,667	44,490
TOTAL NONCURRENT LIABILITIES	2,133,204	2,138,696
TOTAL LIABILITIES	2,408,895	2,387,299
Rate Matters (Note 2)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $15 Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157,230	157,230
Paid-in Capital	364,037	364,037
Retained Earnings	388,530	364,389
Accumulated Other Comprehensive Income (Loss)	6,481	7,149
TOTAL COMMON SHAREHOLDER'S EQUITY	916,278	892,805
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 3,325,173	$ 3,280,104

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	Years Ended December 31,		
	2012	2011	2010
OPERATING ACTIVITIES			
Net Income	$ 114,141	$ 124,628	$ 72,787
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	95,180	95,915	104,929
Deferred Income Taxes	48,916	61,581	92,695
Carrying Costs Income	(1,856)	(4,033)	(3,145)
Allowance for Equity Funds Used During Construction	(2,007)	(1,317)	(804)
Mark-to-Market of Risk Management Contracts	3,740	1,290	160
Pension Contributions to Qualified Plan Trust	(12,306)	(33,189)	(12,848)
Fuel Over/Under-Recovery, Net	12,258	32,949	(88,349)
Change in Other Noncurrent Assets	7,436	14,883	(19,279)
Change in Other Noncurrent Liabilities	4,762	32,196	16,612
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	4,422	44,414	(10,094)
Fuel, Materials and Supplies	(3,067)	(4,778)	(617)
Accounts Payable	3,158	(20,068)	(20,601)
Accrued Taxes, Net	5,006	19,535	(23,605)
Other Current Assets	(970)	4,855	4,446
Other Current Liabilities	5,538	10,628	(18,341)
Net Cash Flows from Operating Activities	284,351	379,489	93,946
INVESTING ACTIVITIES			
Construction Expenditures	(224,295)	(140,327)	(194,896)
Change in Advances to Affiliates, Net	29,318	(39,876)	62,695
Other Investing Activities	1,723	1,126	(368)
Net Cash Flows Used for Investing Activities	(193,254)	(179,077)	(132,569)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	2,395	248,909	2,240
Change in Advances from Affiliates, Net	-	(91,382)	91,382
Retirement of Long-term Debt – Nonaffiliated	(229)	(275,000)	-
Retirement of Cumulative Preferred Stock	-	(5,152)	(300)
Principal Payments for Capital Lease Obligations	(3,481)	(4,189)	(3,991)
Dividends Paid on Common Stock	(90,000)	(72,500)	(51,026)
Dividends Paid on Cumulative Preferred Stock	-	(180)	(200)
Other Financing Activities	172	25	192
Net Cash Flows from (Used for) Financing Activities	(91,143)	(199,469)	38,297
Net Increase (Decrease) in Cash and Cash Equivalents	(46)	943	(326)
Cash and Cash Equivalents at Beginning of Period	1,413	470	796
Cash and Cash Equivalents at End of Period	$ 1,367	$ 1,413	$ 470
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 52,403	$ 37,573	$ 57,970
Net Cash Paid (Received) for Income Taxes	27,229	(16,043)	(16,770)
Noncash Acquisitions Under Capital Leases	1,542	1,078	13,794
Construction Expenditures Included in Current Liabilities as of December 31,	27,118	28,427	6,842

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to PSO's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to PSO. The footnotes begin on page 217.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Company Overview

As a public utility, SWEPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 524,000 retail customers in its service territory in northeastern and panhandle of Texas, northwestern Louisiana and western Arkansas. SWEPCo consolidates its wholly-owned subsidiary, Southwest Arkansas Utilities Corporation. SWEPCo also consolidates Sabine Mining Company, a variable interest entity. SWEPCo sells electric power at wholesale to other utilities, municipalities and electric cooperatives.

SWEPCo, as a party to the CSW Operating Agreement, is compensated for energy delivered to the other member based upon the delivering member's incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. PSO and SWEPCo share the revenues and costs for sales to neighboring utilities and power marketers made by AEPSC on their behalf based upon the relative magnitude of the energy each company provides to make such sales. SWEPCo shares these margins with its customers.

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 SWEPCo's behalf. SWEPCo shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the AEP East Companies and PSO. Power and gas risk management activities are allocated based on the CSW Operating Agreement and the SIA. SWEPCo 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.

SWEPCo is jointly and severally liable for activity conducted by AEPSC on the behalf of PSO and SWEPCo related to power purchase and sale activity pursuant to the SIA.

Regulatory Activity

Turk Plant

SWEPCo constructed the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which was placed into service in December 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and operates the completed facility. See the "Turk Plant" section of Note 2.

Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates by $83 million, primarily due to the Turk Plant, based upon an 11.25% return on common equity to be effective January 2013. The requested base rate increase included a return on and of the Texas jurisdictional share (approximately 33%) of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operation and maintenance costs. In September 2012, an Administrative Law Judge issued an order that granted the establishment of SWEPCo's existing rates as temporary rates beginning in late January 2013, subject to true-up to the final PUCT-approved rates. In December 2012, several intervenors filed opposing testimony with various recommendations. A decision from the PUCT is expected in the second quarter of 2013. See "2012 Texas Base Rate Case" section of Note 2.

Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share (approximately 29%) of the Turk Plant. In February 2013, a settlement was filed and a hearing was conducted. The settlement provided that SWEPCo would increase Louisiana total rates by approximately $2 million annually, effective March 2013, consisting of an increase in base rates of approximately $85 million annually offset by a decrease in fuel rates of approximately $83 million annually. The proposed March 2013 base rates are based on a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund based on the staff review of the cost of service and prudence review of the Turk Plant to be initiated by SWEPCo no later than May 2013. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover all non-fuel Turk Plant costs and a full weighted-average cost of capital return on the Turk Plant portion of rate base beginning January 2013. A decision from the LPSC is expected in the first quarter of 2013.

Flint Creek Plant Environmental Controls

In February 2012, SWEPCo filed a petition with the APSC seeking a declaratory order to install environmental controls at the Flint Creek Plant to comply with the standards established by the CAA. The estimated cost of the project is $408 million, excluding AFUDC and company overheads. As a joint owner of the Flint Creek Plant, SWEPCo's portion of those costs is estimated at $204 million. As of December 31, 2012, SWEPCo has incurred $11 million related to this project, including AFUDC and company overheads. The APSC staff and the Sierra Club filed testimony that recommended the APSC deny the requested declaratory order. A hearing is scheduled for March 2013. If SWEPCo is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

Litigation and Environmental Issues

In the ordinary course of business, SWEPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 2 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 353 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2012	2011	2010
	(in millions of KWhs)		
Retail:			
Residential	6,301	6,908	6,361
Commercial	6,103	6,280	6,117
Industrial	5,661	5,408	5,254
Miscellaneous	81	82	81
Total Retail	18,146	18,678	17,813
Wholesale	7,762	7,947	7,333
Total KWhs	25,908	26,625	25,146

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2012	2011	2010
	(in degree days)		
Actual - Heating (a)	860	1,271	1,543
Normal - Heating (b)	1,259	1,260	1,253
Actual - Cooling (c)	2,605	2,874	2,592
Normal - Cooling (b)	2,256	2,231	2,213

(a) Western Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Western Region cooling degree days are calculated on a 65 degree temperature base.

2012 Compared to 2011

Reconciliation of Year Ended December 31, 2011 to Year Ended December 31, 2012
Net Income
(in millions)

Year Ended December 31, 2011	$	165
Changes in Gross Margin:		
Retail Margins (a)		(18)
Off-system Sales		1
Transmission Revenues		4
Other Revenues		(2)
Total Change in Gross Margin		(15)
Changes in Expenses and Other:		
Other Operation and Maintenance		18
Asset Impairment and Other Related Charges		36
Depreciation and Amortization		(5)
Taxes Other Than Income Taxes		(7)
Interest Income		(1)
Allowance for Equity Funds Used During Construction		8
Interest Expense		(7)
Total Change in Expenses and Other		42
Income Tax Expense		11
Year Ended December 31, 2012	$	203

(a) Includes firm wholesale sales to municipals and cooperatives.

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** decreased $18 million primarily due to the following:
  - A $23 million decrease in weather-related usage primarily due to a 9% decrease in cooling degree days and a 32% decrease in heating degree days.
  - A $14 million decrease primarily due to fuel expense adjustments.

  These decreases were partially offset by:
  - An $18 million increase in municipal and cooperative revenues due to higher rates and formula rate adjustments.
- **Transmission Revenues** increased $4 million due to higher rates in the SPP region.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $18 million primarily due to the following:
  - A $12 million decrease in generation maintenance expenses primarily due to higher 2011 planned and unplanned plant outages.
  - An $11 million decrease in distribution maintenance expenses primarily due to decreased vegetation management expenses.
  - A $5 million decrease related to 2011 litigation expenses.

  These decreases were partially offset by:
  - A $6 million increase due to expenses related to the 2012 sustainable cost reductions.
  - A $5 million increase in employee-related expenses.
- **Asset Impairment and Other Related Charges** decreased $36 million due to the 2011 write-off of $49 million related to the expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap as a result of the November 2011 Texas Court of Appeals decision. This was partially offset by the 2012 write-off of an additional $13 million related to the Texas capital cost cap.

- **Depreciation and Amortization** expenses increased $5 million primarily due to a greater depreciable base.
- **Taxes Other Than Income Taxes** increased $7 million primarily due to favorable property tax adjustments made in 2011.
- **Allowance for Equity Funds Used During Construction** increased $8 million primarily due to construction of the Turk Plant.
- **Interest Expense** increased $7 million primarily due to the issuance of Senior Unsecured Notes, partially offset by an increase in the debt component of AFUDC due to construction of the Turk Plant.
- **Income Tax Expense** decreased $11 million primarily due to state book/tax differences which are accounted for on a flow-through basis, partially offset by an increase in pretax book income.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 353 for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and pension and other postretirement benefits.

See the "Accounting Pronouncements" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 353 for a discussion of accounting pronouncements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Southwestern Electric Power Company:

We have audited the accompanying consolidated balance sheets of Southwestern Electric Power Company Consolidated (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Southwestern Electric Power Company Consolidated as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 26, 2013

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Southwestern Electric Power Company Consolidated (SWEPCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. SWEPCo's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of SWEPCo's internal control over financial reporting as of December 31, 2012. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management's assessment, SWEPCo's internal control over financial reporting was effective as of December 31, 2012.

This annual report does not include an attestation report of SWEPCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit SWEPCo to provide only management's report in this annual report.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	Years Ended December 31, 2012	2011	2010
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,538,533	$ 1,594,192	$ 1,469,514
Sales to AEP Affiliates	37,441	57,615	51,870
Other Revenues	1,860	2,019	2,150
TOTAL REVENUES	1,577,834	1,653,826	1,523,534
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	579,721	626,599	587,058
Purchased Electricity for Resale	131,706	152,645	125,064
Purchased Electricity from AEP Affiliates	19,229	11,808	23,707
Other Operation	230,078	224,068	245,504
Maintenance	117,415	140,981	103,352
Asset Impairment and Other Related Charges	13,000	49,000	-
Depreciation and Amortization	138,778	133,229	126,901
Taxes Other Than Income Taxes	72,011	65,239	63,151
TOTAL EXPENSES	1,301,938	1,403,569	1,274,737
OPERATING INCOME	275,896	250,257	248,797
Other Income (Expense):			
Interest Income	1,230	2,076	579
Allowance for Equity Funds Used During Construction	57,054	48,731	45,646
Interest Expense	(88,318)	(81,781)	(86,538)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	245,862	219,283	208,484
Income Tax Expense	45,858	56,903	64,214
Equity Earnings of Unconsolidated Subsidiary	2,509	2,746	2,414
NET INCOME	202,513	165,126	146,684
Net Income Attributable to Noncontrolling Interest	3,622	3,841	4,093
NET INCOME ATTRIBUTABLE TO SWEPCo SHAREHOLDERS	198,891	161,285	142,591
Preferred Stock Dividend Requirements Including Capital Stock Expense	-	579	229
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 198,891	$ 160,706	$ 142,362

The common stock of SWEPCo is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	Years Ended December 31,		
	2012	**2011**	**2010**
Net Income	$ 202,513	$ 165,126	$ 146,684
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $13, $6,103 and $401 in 2012, 2011 and 2010, Respectively	(25)	(11,334)	745
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $358, $275 and $505 in 2012, 2011 and 2010, Respectively	665	511	937
Pension and OPEB Funded Status, Net of Tax of $4,477, $1,885 and $636 in 2012, 2011 and 2010, Respectively	8,315	(3,501)	(1,182)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	8,955	(14,324)	500
TOTAL COMPREHENSIVE INCOME	211,468	150,802	147,184
Total Comprehensive Income Attributable to Noncontrolling Interest	3,622	3,841	4,093
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo SHAREHOLDERS	$ 207,846	$ 146,961	$ 143,091

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2009	$ 135,660	$ 674,979	$ 726,478	$ (12,991)	$ 31	$ 1,524,157
Common Stock Dividends – Nonaffiliated					(3,763)	(3,763)
Preferred Stock Dividends			(229)			(229)
Subtotal – Equity						1,520,165
Net Income			142,591		4,093	146,684
Other Comprehensive Income				500		500
TOTAL EQUITY – DECEMBER 31, 2010	135,660	674,979	868,840	(12,491)	361	1,667,349
Common Stock Dividends – Nonaffiliated					(3,811)	(3,811)
Preferred Stock Dividends			(210)			(210)
Loss on Reacquired Preferred Stock		(373)				(373)
Subtotal – Equity						1,662,955
Net Income			161,285		3,841	165,126
Other Comprehensive Loss				(14,324)		(14,324)
TOTAL EQUITY – DECEMBER 31, 2011	135,660	674,606	1,029,915	(26,815)	391	1,813,757
Common Stock Dividends – Nonaffiliated					(3,752)	(3,752)
Subtotal – Equity						1,810,005
Net Income			198,891		3,622	202,513
Other Comprehensive Income				8,955		8,955
TOTAL EQUITY – DECEMBER 31, 2012	$ 135,660	$ 674,606	$ 1,228,806	$ (17,860)	$ 261	$ 2,021,473

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2012 and 2011
(in thousands)

	December 31, 2012	December 31, 2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2,036	$ 801
Advances to Affiliates	153,829	-
Accounts Receivable:		
Customers	39,349	35,054
Affiliated Companies	26,288	23,730
Miscellaneous	35,514	19,370
Allowance for Uncollectible Accounts	(2,041)	(989)
Total Accounts Receivable	99,110	77,165
Fuel (December 31, 2012 and 2011 Amounts Include $42,084 and $32,651, Respectively, Related to Sabine)	134,234	102,015
Materials and Supplies	69,212	55,325
Risk Management Assets	695	445
Deferred Income Tax Benefits	101,403	8,195
Accrued Tax Benefits	9,616	1,541
Regulatory Asset for Under-Recovered Fuel Costs	8,527	10,843
Prepayments and Other Current Assets	16,489	16,827
TOTAL CURRENT ASSETS	595,151	273,157
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	3,888,230	2,326,102
Transmission	1,115,795	988,534
Distribution	1,758,988	1,675,764
Other Property, Plant and Equipment (December 31, 2012 and 2011 Amounts include $287,032 and $232,948, Respectively, Related to Sabine)	688,254	637,019
Construction Work in Progress	99,783	1,443,569
Total Property, Plant and Equipment	7,551,050	7,070,988
Accumulated Depreciation and Amortization (December 31, 2012 and 2011 Amounts Include $116,597 and $103,586, Respectively, Related to Sabine)	2,284,258	2,211,912
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,266,792	4,859,076
OTHER NONCURRENT ASSETS		
Regulatory Assets	403,278	394,276
Long-term Risk Management Assets	-	282
Deferred Charges and Other Noncurrent Assets	76,432	74,992
TOTAL OTHER NONCURRENT ASSETS	479,710	469,550
TOTAL ASSETS	$ 6,341,653	$ 5,601,783

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2012 and 2011

	December 31, 2012	December 31, 2011
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 132,473
Accounts Payable:		
General	126,768	181,268
Affiliated Companies	62,835	59,201
Short-term Debt – Nonaffiliated	2,603	17,016
Long-term Debt Due Within One Year – Nonaffiliated	3,250	20,000
Risk Management Liabilities	1,128	24,359
Customer Deposits	69,393	52,095
Accrued Taxes	31,532	44,404
Accrued Interest	43,950	39,629
Obligations Under Capital Leases	17,599	15,058
Regulatory Liability for Over-Recovered Fuel Costs	16,761	5,032
Other Current Liabilities	64,997	64,413
TOTAL CURRENT LIABILITIES	440,816	654,948
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,042,978	1,708,637
Long-term Risk Management Liabilities	-	221
Deferred Income Taxes	1,075,551	665,668
Regulatory Liabilities and Deferred Investment Tax Credits	476,471	428,571
Asset Retirement Obligations	78,017	65,673
Employee Benefits and Pension Obligations	38,240	87,159
Obligations Under Capital Leases	114,161	112,802
Deferred Credits and Other Noncurrent Liabilities	53,946	64,347
TOTAL NONCURRENT LIABILITIES	3,879,364	3,133,078
TOTAL LIABILITIES	4,320,180	3,788,026
Rate Matters (Note 2)		
Commitments and Contingencies (Note 4)		
EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 7,600,000 Shares		
Outstanding – 7,536,640 Shares	135,660	135,660
Paid-in Capital	674,606	674,606
Retained Earnings	1,228,806	1,029,915
Accumulated Other Comprehensive Income (Loss)	(17,860)	(26,815)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,021,212	1,813,366
Noncontrolling Interest	261	391
TOTAL EQUITY	2,021,473	1,813,757
TOTAL LIABILITIES AND EQUITY	$ 6,341,653	$ 5,601,783

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011 and 2010
(in thousands)

	Years Ended December 31, 2012	2011	2010
OPERATING ACTIVITIES			
Net Income	$ 202,513	$ 165,126	$ 146,684
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	138,778	133,229	126,901
Deferred Income Taxes	260,761	16,726	81,764
Asset Impairment and Other Related Charges	13,000	49,000	-
Allowance for Equity Funds Used During Construction	(57,054)	(48,731)	(45,646)
Mark-to-Market of Risk Management Contracts	(4,159)	1,732	4,826
Pension Contributions to Qualified Plan Trust	(13,192)	(31,263)	(29,065)
Fuel Over/Under-Recovery, Net	14,045	(21,485)	(6,089)
Change in Regulatory Liabilities	37,955	28,031	26,671
Change in Other Noncurrent Assets	21,309	24,519	(15,207)
Change in Other Noncurrent Liabilities	14,594	20,904	21,958
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(21,919)	20,751	(21,507)
Fuel, Materials and Supplies	(46,106)	(15,168)	21,498
Accounts Payable	3,813	1,168	(23,004)
Accrued Taxes, Net	(16,057)	40,189	(18,788)
Accrued Interest	4,294	(910)	6,570
Other Current Assets	(387)	2,983	(3,182)
Other Current Liabilities	(7,905)	340	(1,433)
Net Cash Flows from Operating Activities	544,283	387,141	272,951
INVESTING ACTIVITIES			
Construction Expenditures	(542,427)	(551,163)	(420,485)
Change in Advances to Affiliates, Net	(153,829)	86,222	(34,405)
Acquisitions of Assets	(1,091)	(8,045)	(103,225)
Other Investing Activities	2,696	2,102	4,945
Net Cash Flows Used for Investing Activities	(694,651)	(470,884)	(553,170)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	336,418	-	399,394
Credit Facility Borrowings	25,123	58,435	99,688
Change in Advances from Affiliates, Net	(132,473)	132,473	-
Retirement of Long-term Debt – Nonaffiliated	(21,625)	(41,135)	(53,500)
Retirement of Long-term Debt – Affiliated	-	-	(50,000)
Retirement of Cumulative Preferred Stock	-	(5,069)	(1)
Credit Facility Repayments	(39,536)	(47,636)	(100,361)
Principal Payments for Capital Lease Obligations	(16,537)	(13,675)	(12,183)
Dividends Paid on Common Stock – Nonaffiliated	(3,752)	(3,811)	(3,763)
Dividends Paid on Cumulative Preferred Stock	-	(210)	(229)
Other Financing Activities	3,985	3,658	1,027
Net Cash Flows from Financing Activities	151,603	83,030	280,072
Net Increase (Decrease) in Cash and Cash Equivalents	1,235	(713)	(147)
Cash and Cash Equivalents at Beginning of Period	801	1,514	1,661
Cash and Cash Equivalents at End of Period	$ 2,036	$ 801	$ 1,514
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 68,918	$ 71,713	$ 70,729
Net Cash Paid (Received) for Income Taxes	(191,638)	(336)	8,350
Noncash Acquisitions Under Capital Leases	20,547	13,334	1,593
Construction Expenditures Included in Current Liabilities as of December 31,	55,767	109,600	94,836
Noncash Assumption of Liabilities Related to Acquisitions	-	-	8,400

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 217.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to SWEPCo's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to SWEPCo. The footnotes begin on page 217.

INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to financial statements that follow are a combined presentation for the Registrant Subsidiaries. The following list indicates the registrants to which the footnotes apply:

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by the Registrant Subsidiaries is the generation, transmission and distribution of electric power. These companies are subject to regulation by the FERC under the Federal Power Act and the Energy Policy Act of 2005 and maintain accounts in accordance with the FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

The Registrant Subsidiaries also engage in wholesale electricity marketing and risk management activities in the United States. I&M provides barging services to both affiliated and nonaffiliated companies. SWEPCo, through consolidated and nonconsolidated affiliates, conducts lignite mining operations to fuel certain of its generation facilities.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

The Registrant Subsidiaries' rates are regulated by the FERC and state regulatory commissions in the nine state operating territories in which they operate. The FERC also regulates the Registrant Subsidiaries' affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires 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. The Registrant Subsidiaries' wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when the Registrant Subsidiaries negotiate and file a cost-based contract with the FERC or the FERC determines that the Registrant Subsidiaries have "market power" in the region where the transaction occurs. The Registrant Subsidiaries have 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. PSO's and SWEPCo's wholesale power transactions in the SPP region are cost-based due to the FERC's finding that PSO and SWEPCo have market power in the SPP region.

The state regulatory commissions regulate all of the retail distribution operations and rates of the Registrant Subsidiaries on a cost basis. The state regulatory commissions also regulate the retail generation/power supply operations and rates except in Ohio. The ESP rates in Ohio continue the process of aligning generation/power supply rates over time with market rates.

The FERC also regulates the Registrant Subsidiaries' wholesale transmission operations and rates. The FERC claims jurisdiction over retail transmission rates when retail rates are unbundled in connection with restructuring. OPCo's retail transmission rates in Ohio, APCo's retail transmission rates in Virginia and I&M's retail transmission rates in Michigan are unbundled and are based on formula rates included in the PJM OATT that are cost-based. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions.

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 Registrant Subsidiaries that are parties to each agreement. In October 2012, the AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and the AEP System Interim Allowance Agreement and approve a new Power Coordination Agreement among APCo, I&M and KPCo. A decision is expected from the FERC in mid-2013.

Principles of Consolidation

The consolidated financial statements for APCo include the Registrant Subsidiary and its wholly-owned subsidiaries. The consolidated financial statements for I&M include the Registrant Subsidiary, its wholly-owned subsidiaries and DCC Fuel (substantially-controlled VIEs). The consolidated financial statements for OPCo include the Registrant Subsidiary and a wholly-owned subsidiary. The consolidated financial statements for SWEPCo include the Registrant Subsidiary, a wholly-owned subsidiary and Sabine (a substantially-controlled VIE). Intercompany items are eliminated in consolidation. The Registrant Subsidiaries use the equity method of accounting for equity investments where they exercise significant influence but do not hold a controlling financial interest. Such investments are recorded as Deferred Charges and Other Noncurrent Assets on the balance sheets; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on the statements of income. OPCo, PSO and SWEPCo have ownership interests in generating units that are jointly-owned with nonaffiliated companies. The proportionate share of the operating costs associated with such facilities is included in the income statements and the assets and liabilities are reflected in the balance sheets. See Note 14 – Variable Interest Entities.

Accounting for the Effects of Cost-Based Regulation

As rate-regulated electric public utility companies, the Registrant Subsidiaries' 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," the Registrant Subsidiaries record regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates. Due to the passage of legislation requiring restructuring and a transition to customer choice and market-based rates, OPCo applies "Regulated Operations" accounting treatment only to specifically approved portions of its generation business consisting of fuel and capacity costs.

Use of Estimates

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

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Inventory

Fossil fuel inventories are 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, the Registrant Subsidiaries accrue and recognize, as Accrued Unbilled Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, through purchase agreements with I&M, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. See "Sale of Receivables – AEP Credit" section of Note 12 for additional information.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense related to receivables purchased from the Registrant Subsidiaries under a sale of receivables agreement. For receivables related to APCo's West Virginia operations, the bad debt reserve is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable. 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

The Registrant Subsidiaries do not have any significant customers that comprise 10% or more of their operating revenues as of December 31, 2012.

The Registrant Subsidiaries monitor credit levels and the financial condition of their customers on a continuing basis to minimize credit risk. The regulatory commissions allow recovery in rates for a reasonable level of bad debt costs. Management believes adequate provisions for credit loss have been made in the accompanying Registrant Subsidiary financial statements.

Emission Allowances

The Registrant Subsidiaries in regulated jurisdictions including Ohio through December 31, 2014, record emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. OPCo records allowances expected to be consumed subsequent to December 31, 2014 at the lower of cost or market when allowances are no longer included in the FAC due to energy auctions of SSO load. The Registrant Subsidiaries follow the inventory model for these allowances. Allowances expected to be consumed within one year are reported in Materials and Supplies. Allowances with expected consumption beyond one year are included in Deferred Charges and Other Noncurrent Assets. These allowances are consumed in the production of energy and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost. Allowances held for speculation are included in Prepayments and Other Current Assets. The purchases and sales of allowances are reported in the Operating Activities section of the statements of cash flows. The net margin on sales of emission allowances is included in Electric Generation, Transmission and Distribution Revenues for nonaffiliated transactions and in Sales to AEP Affiliates Revenues for affiliated transactions because of its integral nature to the production process of energy and the Registrant Subsidiaries' revenue optimization strategy for their operations. The net margin on sales of emission allowances affects the determination of deferred fuel or deferred emission allowance costs and the amortization of regulatory assets for certain jurisdictions.

Property, Plant and Equipment and Equity Investments

Regulated

Electric utility property, plant and equipment for rate-regulated operations are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities. 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 held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense. Equity investments are required to be tested for impairment when it is determined there may be an other-than-temporary loss in value.

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.

Nonregulated

The generation operations of OPCo and the mining operations of SWEPCo generally follow the policies of rate-regulated operations listed above but with the following exceptions. Property, plant and equipment of nonregulated operations and equity investments (included in Deferred Charges and Other Noncurrent Assets) are stated at fair value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for most nonregulated operations under the group composite method of depreciation. A gain or loss would be recorded if the retirement is not considered an interim routine replacement. Removal costs are charged to expense.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

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. For nonregulated operations, including generating assets owned by OPCo and mining operations at SWEPCo, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest." The Registrant Subsidiaries record the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense.

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Advances to/from Affiliates, Accounts Receivable, Accounts Payable and Short-term Debt 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 for I&M approximates the best estimate of its fair value.

Fair Value Measurements of Assets and Liabilities

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

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

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

Assets in the benefits and nuclear trusts and Other Cash Deposits are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities 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 Fuel and Other Consumables Used for Electric Generation 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 current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally deferred as current regulatory assets. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a phase-in plan or the FAC has been suspended. These deferrals are amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit the Registrant Subsidiaries' fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a fuel cost disallowance becomes probable, the Registrant Subsidiaries adjust their FAC deferrals and record provisions for estimated refunds to recognize these probable outcomes.

Changes in fuel costs, including purchased power in Indiana and Michigan for I&M, in Ohio (beginning in 2012 through the ESP related to non-auction standard service offer load served) for OPCo, in Arkansas, Louisiana and Texas for SWEPCo, in Oklahoma for PSO and in Virginia for APCo are reflected in rates in a timely manner generally through the FAC. Changes in fuel costs, including purchased power in Ohio (beginning in 2009 through 2011) for OPCo and in West Virginia for APCo are reflected in rates through FAC phase-in plans. The FAC generally includes some sharing of off-system sales. In West Virginia for APCo, all of the profits from off-system sales are given to customers through the FAC. None of the profits from off-system sales are given to customers through the FAC in Ohio for OPCo. A portion of profits from off-system sales are given to customers through the FAC and other rate mechanisms in Oklahoma for PSO, Arkansas, Louisiana and Texas for SWEPCo, Virginia for APCo and in Indiana and Michigan (all areas of Michigan beginning in December 2010) for I&M. Where the FAC or off-system sales sharing mechanism is capped, frozen or non-existent, changes in fuel costs or sharing of off-system sales impacted earnings.

Revenue Recognition

Regulatory Accounting

The financial statements of the Registrant Subsidiaries 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, the Registrant Subsidiaries record them as assets on the balance sheets. The Registrant Subsidiaries test for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, the Registrant Subsidiaries write off that regulatory asset as a charge against income.

Electricity Supply and Delivery Activities

The Registrant Subsidiaries recognize revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. The Registrant Subsidiaries recognize the revenues on the statements of income upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

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. Generally, these power sales and purchases are reported on a net basis as revenues on the statements of income. However, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are recorded gross as Purchased Electricity for Resale on the statements of income. Other RTOs in which the Registrant Subsidiaries participate 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 Purchased Electricity for Resale 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 Purchased Electricity for Resale on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, the Registrant Subsidiaries record expenses when purchased electricity is received and when expenses are incurred. For certain power purchase contracts that are derivatives and accounted for using MTM accounting, OPCo records these contracts on a net basis in revenues. In other jurisdictions where the generation/supply business is subject to cost-based regulation, 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 the Registrant Subsidiaries, 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. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. Certain energy marketing and risk management transactions are with RTOs.

The Registrant Subsidiaries recognize revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. The Registrant Subsidiaries use 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. The Registrant Subsidiaries include realized gains and losses on wholesale marketing and risk management transactions in revenues on a net basis. For OPCo, unrealized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM are included in revenues on a net basis. For APCo, I&M, PSO and SWEPCo, who are subject to cost-based regulation, unrealized MTM amounts and some realized gains and losses are deferred as regulatory assets (for losses) and regulatory liabilities (for gains). Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities as appropriate.

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). The Registrant Subsidiaries initially record 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, the Registrant Subsidiaries subsequently reclassify the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on their statements of income. For OPCo, the ineffective portion of the gain or loss is recognized in revenues or expense on the income statements immediately. APCo, I&M, PSO and SWEPCo, who are subject to cost-based regulation, defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Accounting for Cash Flow Hedging Strategies" section of Note 8.

Levelization of Nuclear Refueling Outage Costs

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

Maintenance

The Registrant Subsidiaries expense maintenance costs as incurred. If it becomes probable that the Registrant Subsidiaries will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. In certain regulatory jurisdictions, the Registrant Subsidiaries defer costs above the level included in base rates and amortize those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment Tax Credits

The Registrant Subsidiaries use 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.

The Registrant Subsidiaries account for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." The Registrant Subsidiaries classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation expense.

Excise Taxes

As agents for some state and local governments, the Registrant Subsidiaries collect from customers certain excise taxes levied by those state or local governments on customers. The Registrant Subsidiaries do not record these taxes as revenue or expense.

Government Grants

For APCo's commercial scale carbon capture and sequestration facility at the Mountaineer Plant and OPCo's gridSMART® demonstration program, APCo and OPCo are reimbursed by the Department of Energy for allowable costs incurred during the billing period. In addition, AEP built a cyber security operations center that will be used to enhance the capabilities for identifying cyber risks or threats, which was also partially funded by the gridSMART® demonstration grant for OPCo's incurred costs. These reimbursements result in the reduction of Other Operation and Maintenance expenses on the statements of income or a reduction in Construction Work in Progress on the balance sheets.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. The Registrant Subsidiaries report gains and losses on the reacquisition of debt for operations that are not subject to cost-based rate regulation in Interest Expense.

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. The net amortization expense is included in Interest Expense.

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	40.0 %
Fixed Income	50.0 %
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 any single issuer
- 5% for private placements
- 5% for convertible securities
- 60% for bonds rated AA+ or lower
- 50% for bonds rated A+ or lower
- 10% for bonds rated BBB- or lower

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

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

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and development risk classifications and some investments in Real Estate Investment Trusts (REITs), which are publicly traded real estate securities 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 multiple general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investment instruments. Commingled private equity funds are used to enhance the holdings' diversity.

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for cash collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the cash collateral is invested. The difference between the rebate owed to the borrower and the cash collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is providing modest incremental income with a limited increase in risk.

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

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

Nuclear Trust Funds

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

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

I&M maintains trust funds for each regulatory jurisdiction. The trust assets may not be used for another jurisdiction's liabilities. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

I&M records securities held in these trust funds in Spent Nuclear Fuel and Decommissioning Trusts on its balance sheets. I&M records these securities at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments for investments in both debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the 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 gain or loss due to the adjusted cost of investment. I&M records unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. See the "Nuclear Contingencies" section of Note 4 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 9 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss)

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

Accumulated Other Comprehensive Income (Loss) (AOCI)

AOCI is included on the balance sheets in the equity section. Components of AOCI for the Registrant Subsidiaries as of December 31, 2012 and 2011 are shown in the following table:

	December 31, 2012	December 31, 2011
	(in thousands)	
Cash Flow Hedges, Net of Tax		
APCo	$ 1,433	$ (285)
I&M	(20,093)	(15,284)
OPCo	7,183	7,706
PSO	6,481	7,149
SWEPCo	(15,549)	(15,524)
Amortization of Pension and OPEB Deferred Costs, Net of Tax		
APCo	$ 19,118	$ 15,521
I&M	4,201	3,088
OPCo	45,938	32,977
SWEPCo	4,778	4,113
Pension and OPEB Funded Status, Net of Tax		
APCo	$ (50,449)	$ (73,779)
I&M	(12,991)	(16,025)
OPCo	(218,846)	(238,405)
SWEPCo	(7,089)	(15,404)

Earnings Per Share (EPS)

The Registrant Subsidiaries are wholly-owned subsidiaries of AEP. Therefore, none are required to report EPS.

OPCo Revised Depreciation Rates

Effective December 1, 2011, OPCo revised book depreciation rates for certain of OPCo's generating plants consistent with shortened depreciable lives for the generating units. This change in depreciable lives resulted in a $52 million increase in depreciation expense in 2012.

In the fourth quarter of 2012, OPCo impaired the generating units discussed above (see Note 6). As a result of this impairment of the full book value of these assets, OPCo ceased depreciation on these generating units effective December 1, 2012.

2. RATE MATTERS

The Registrant Subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. Rate matters can have a material impact on net income, cash flows and possibly financial condition. The Registrant Subsidiaries' recent significant rate orders and pending rate filings are addressed in this note.

OPCo Rate Matters

Ohio Electric Security Plan Filing

2009 – 2011 ESP

The PUCO issued an order in March 2009 that modified and approved the ESP which established rates at the start of the April 2009 billing cycle through 2011. OPCo collected the 2009 annualized revenue increase over the last nine months of 2009. The order also provided a phase-in FAC, which was authorized to be recovered through a non-bypassable surcharge over the period 2012 through 2018. The PUCO's March 2009 order was appealed to the Supreme Court of Ohio, which issued an opinion and remanded certain issues back to the PUCO.

In October 2011, the PUCO issued an order in the remand proceeding. As a result, OPCo ceased collection of POLR billings in November 2011 and recorded a write-off in 2011 related to POLR collections for the period June 2011 through October 2011. In February 2012, the Ohio Consumers' Counsel and the IEU filed appeals of that order with the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge, which, if ordered, could reduce OPCo's net deferred fuel costs up to the total balance. As of December 31, 2012, OPCo's net deferred fuel balance was $519 million, excluding unrecognized equity carrying costs. A decision from the Supreme Court of Ohio is pending.

In January 2011, the PUCO issued an order on the 2009 SEET filing, which resulted in a write-off in 2010 and a subsequent refund to customers during 2011. The IEU and the Ohio Energy Group filed appeals with the Supreme Court of Ohio challenging the PUCO's SEET decision. In December 2012, the Supreme Court of Ohio issued an order which rejected all of the intervenors' challenges and affirmed the PUCO decision.

The 2009 SEET order gave consideration for a future commitment to invest $20 million to support the development of a large solar farm. In January 2013, the PUCO found there was not a need for the large solar farm. The PUCO noted that OPCo remains obligated to spend $20 million on this solar project or another similar project by the end of 2013.

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. Subsequent testimony and legal briefs from intervenors recommended a refund of up to $62 million of 2010 earnings, which included off-system sales in the SEET calculation. In December 2011, the PUCO staff filed testimony that recommended a $23 million refund of 2010 earnings. OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO ordered SEET refund. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. The PUCO approved OPCo's request to file the 2011 SEET one month after the PUCO issues an order on the 2010 SEET. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo and in 2012 for OPCo.

Management is unable to predict the outcome of the unresolved litigation discussed above. If these proceedings result in adverse rulings, it could reduce future net income and cash flows and impact financial condition.

January 2012 – May 2016 ESP as Rejected by the PUCO

In December 2011, the PUCO approved an ESP modified stipulation which established a SSO pricing for generation. Various parties filed for rehearing with the PUCO requesting that the PUCO reconsider adoption of the modified stipulation. In February 2012, the PUCO issued an entry on rehearing which rejected the modified stipulation and ordered a return to the 2011 ESP rates. Those rates remained in effect until the new ESP was approved in August 2012. See the "June 2012 – May 2015 ESP Including Capacity Charge" section below.

As a result of the PUCO's rejection of the modified stipulation, OPCo reversed a $35 million obligation to contribute to the Partnership with Ohio and the Ohio Growth Fund and an $8 million regulatory asset for 2011 storm damage, both originally recorded in 2011.

As directed by the February 2012 order, OPCo filed revised tariffs with the PUCO to implement the provisions of the 2011 ESP. Included in the revised tariffs was the Phase-In Recovery Rider (PIRR) to recover deferred fuel costs as authorized under the 2009 – 2011 ESP order. In March 2012, the PUCO issued an order that directed OPCo to file new revised tariffs removing the PIRR and stated that its recovery would be addressed in a future proceeding. OPCo implemented the new revised tariffs in March 2012. In March 2012, OPCo resumed recording a weighted average cost of capital return on the deferred fuel balance in accordance with the 2009 - 2011 ESP order. OPCo also filed a request for rehearing of the March 2012 order relating to the PIRR, which the PUCO denied but provided that all of the substantive concerns and issues raised would be addressed in a separate PIRR docket.

In August 2012, the PUCO ordered implementation of PIRR rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. The August 2012 order was upheld on rehearing by the PUCO in October 2012. In November 2012, OPCo filed an appeal at the Supreme Court of Ohio claiming a long-term debt rate modified the previously adjudicated ESP order, which granted a weighted average cost of capital rate. The IEU and the Ohio Consumers' Counsel also filed appeals at the Supreme Court of Ohio in November 2012 arguing that the PUCO should have reduced the deferred fuel balance to reflect the prior "improper" collection of POLR revenues and reduced carrying costs due to an accumulated deferred income tax credit. See the "2009 – 2011 ESP" section above. These appeals could reduce OPCo's net deferred fuel balance up to the total balance, which would reduce future net income and cash flows. A decision from the Supreme Court of Ohio is pending.

June 2012 – May 2015 ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that establishes base generation rates through May 2015, adopted a 12% earnings threshold for the SEET and allowed the continuation of the fuel adjustment clause. Further, the ESP established a non-bypassable Distribution Investment Rider effective September 2012 through May 2015 to recover, with certain caps, post-August 2010 distribution investment. The ESP also maintained recovery of several previous ESP riders and required OPCo to contribute $2 million per year during the ESP to the Ohio Growth Fund. In addition, the PUCO approved a storm damage recovery mechanism.

As part of the ESP decision, the PUCO ordered OPCo to conduct an energy-only auction for 10% of the SSO load with delivery beginning six months after the receipt of final orders in both the ESP and corporate separation cases and extending through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 50% of the SSO load with delivery beginning June 2014 through May 2015 and for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. OPCo will conduct energy and capacity auctions for its entire SSO load for delivery starting in June 2015.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The RPM price is approximately $20/MW day through May 2013. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio.

As part of the August 2012 PUCO ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is intended to provide approximately $500 million over the ESP period and will be collected from customers at $3.50/MWh through May 2014 and $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the deferred capacity costs. As of December 31, 2012, OPCo recorded $66 million of incurred deferred capacity costs, including debt carrying costs, in Regulatory Assets on the balance sheet. In August 2012, the IEU filed an action with the Supreme Court of Ohio stating, among other things, that OPCo's collection of its capacity costs is illegal. In September 2012, OPCo and the PUCO filed motions to dismiss the IEU's action. If OPCo is ultimately not permitted to fully collect its deferred capacity costs, it would reduce future net income and cash flows and impact financial condition. A decision from the Supreme Court of Ohio is pending.

In January 2013, the PUCO issued its Order on Rehearing for the ESP which generally upheld its August 2012 order including the implementation of the RSR. The PUCO clarified that a final reconciliation of revenues and costs would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket. If OPCo is ultimately not permitted to fully collect its ESP rates, including the RSR, it would reduce future net income and cash flows and impact financial condition.

Corporate Separation

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo's generation assets including the transfer of OPCo's generation assets at net book value to AEPGenCo. AEPGenCo will also assume the associated generation liabilities. In December 2012, the PUCO granted the IEU and Ohio Consumers' Counsel requests for rehearing for the purpose of further consideration and those requests remain pending.

Also in October 2012, filings at the FERC were submitted related to corporate separation. See the "Corporate Separation and Termination of Interconnection Agreement" section below under FERC Rate Matters.

2011 Ohio Distribution Base Rate Case

In December 2011, the PUCO approved a stipulation which provided for no change in distribution rates and a new rider for a $15 million annual credit to residential ratepayers due principally to the inclusion of the rate base distribution investment in the Distribution Investment Rider (DIR) as approved in December 2011 by the modified stipulation in the ESP proceeding. However, when the February 2012 PUCO order rejected the ESP modified stipulation, collection of the DIR terminated. In August 2012, the PUCO approved a new DIR as part of the June 2012 – May 2015 ESP proceeding. The DIR is capped at $86 million in 2012, $104 million in 2013, $124 million in 2014 and $52 million for the period January through May 2015, for a total of $366 million.

Storm Damage Recovery Rider (SDRR)

In December 2012, OPCo submitted an application with the PUCO to establish initial SDRR rates. The SDRR seeks recovery of 2012 incremental storm distribution expenses over twelve months starting with the effective date of the SDRR as approved by the PUCO. If the PUCO extends recovery beyond twelve months and/or does not commence cost recovery by April 2013, OPCo requested approval of a weighted average cost of capital carrying charge, effective April 2013. As of December 31, 2012, OPCo recorded $62 million in Regulatory Assets on the balance sheet related to 2012 storm damage. If OPCo is not ultimately permitted to recover these storm costs, it would reduce future net income and cash flows and impact financial condition.

2009 Fuel Adjustment Clause Audit

The PUCO selected an outside consultant to conduct an audit of OPCo's FAC for 2009. The outside consultant provided its audit report to the PUCO. In January 2012, the PUCO ordered that the remaining $65 million in proceeds from a 2008 coal contract settlement agreement be applied against OPCo's under-recovered fuel balance. In April 2012, on rehearing, the PUCO ordered that the settlement credit only needed to reflect the Ohio retail jurisdictional share of the gain not already flowed through the FAC with carrying charges. OPCo recorded a $30 million net favorable adjustment on the statement of income in the second quarter of 2012. The January 2012 PUCO order also stated that a consultant should be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers. Management is unable to predict the outcome of any future consultant recommendation. If the PUCO ultimately determines that additional amounts should benefit ratepayers as a result of the consultant's review of the coal reserve valuation, it could reduce future net income and cash flows and impact financial condition.

In August 2012, intervenors filed with the Supreme Court of Ohio claiming the settlement credit ordered by the PUCO should have reflected the remaining gain not already flowed through the FAC with carrying charges, which, if ordered, would be $35 million plus carrying charges. If the Supreme Court of Ohio ultimately determines that additional amounts should benefit ratepayers, it could reduce future net income and cash flows and impact financial condition.

2010 and 2011 Fuel Adjustment Clause Audits

The PUCO-selected outside consultant issued its 2010 and 2011 FAC audit reports which included a recommendation that the PUCO reexamine the carrying costs on the deferred FAC balance and determine whether the carrying costs on the balance should be net of accumulated income taxes. As of December 31, 2012, the amount of OPCo's carrying costs that could potentially be reduced due to the accumulated income tax issue is estimated to be approximately $36 million, including $19 million of unrecognized equity carrying costs. These amounts include the carrying costs exposure of the 2009 FAC audit, which has been appealed by an intervenor to the Supreme Court of Ohio. Decisions from the PUCO are pending. Management is unable to predict the outcome of these proceedings. If the PUCO orders result in a reduction to the FAC deferral, it would reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

OPCo and Ormet, a large aluminum company, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. This interim arrangement was approved by the PUCO and was effective from January 2009 through September 2009. In March 2009, the PUCO approved a FAC in the ESP filing and the FAC aspect of the ESP order was upheld by the Supreme Court of Ohio. The approval of the FAC as part of the ESP, together with the PUCO approval of the interim arrangement, provided the basis to record a regulatory asset for the difference between the approved market price and the rate paid by Ormet. Through September 2009, the last month of the interim arrangement, OPCo had $64 million of deferred FAC costs related to the interim arrangement, excluding $2 million of unrecognized equity carrying costs. In November 2009, OPCo requested that the PUCO approve recovery of the deferral under the interim agreement plus a weighted average cost of capital carrying charge. The deferral amount is included in OPCo's FAC phase-in deferral balance. In the 2009 – 2011 ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related regulatory asset and requested that the PUCO prevent OPCo from collecting the Ormet-related revenues in the future. The PUCO did not take any action on this request. The intervenors raised the issue again in response to OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement. This issue remains pending before the PUCO. If OPCo is not ultimately permitted to fully recover its requested deferrals under the interim arrangement, it would reduce future net income and cash flows and impact financial condition.

Special Rate Mechanism for Ormet

In October 2012, the PUCO issued an order approving a delayed payment plan for Ormet of its October and November 2012 power billings totaling $27 million to be paid in equal monthly installment over the period January 2014 to May 2015 without interest. In the event Ormet does not pay the $27 million, the PUCO permitted OPCo to recover the unpaid balance, up to $20 million, in the economic development rider. To the extent unpaid amounts exceed $20 million, it will reduce future net income and cash flows.

Ohio IGCC Plant

In March 2005, OPCo filed an application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. As of December 31, 2012, OPCo has collected $24 million in pre-construction costs authorized in a June 2006 PUCO order. Intervenors have filed motions with the PUCO requesting all collected pre-construction costs be refunded to Ohio ratepayers with interest.

Management cannot predict the outcome of these proceedings concerning the Ohio IGCC plant or what effect, if any, these proceedings would have on future net income and cash flows. However, if OPCo is required to refund pre-construction costs collected, it could reduce future net income and cash flows and impact financial condition.

SWEPCo Rate Matters

Turk Plant

SWEPCo constructed the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which was placed into service in December 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and operates the completed facility. As of December 31, 2012, excluding costs attributable to its joint owners and a $62 million provision for a Texas capital costs cap, SWEPCo has capitalized approximately $1.7 billion of expenditures, including AFUDC and capitalized interest of $328 million and related transmission costs of $120 million.

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the 88 MW SWEPCo Arkansas jurisdictional share of the Turk Plant. Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. In June 2010, in response to the Arkansas Supreme Court's decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This portion of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the SPP market.

The PUCT approved a Certificate of Convenience and Necessity (CCN) for the Turk Plant with the following conditions: (a) a cap on the recovery of jurisdictional capital costs for the Turk Plant based on the previously estimated $1.522 billion projected construction cost, excluding AFUDC and related transmission costs, (b) a cap on recovery of annual CO_2 emission costs at $28 per ton through the year 2030 and (c) a requirement to hold Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers. SWEPCo appealed the PUCT's order contending the two cost cap restrictions are unlawful. The Texas Industrial Energy Consumers (TIEC) filed an appeal contending that the PUCT's grant of a conditional CCN for the Turk Plant should be revoked because the Turk Plant is unnecessary to serve retail customers. The Texas District Court and the Texas Court of Appeals affirmed the PUCT's order in all respects. In April 2012, SWEPCo and TIEC filed petitions for review at the Supreme Court of Texas. The Supreme Court of Texas has requested full briefing from the parties.

If SWEPCo cannot recover all of its investment and expenses related to the Turk Plant, it would reduce future net income and cash flows and impact financial condition.

2012 Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates by $83 million, primarily due to the Turk Plant, based upon an 11.25% return on common equity to be effective January 2013. The requested base rate increase included a return on and of the Texas jurisdictional share (approximately 33%) of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operation and maintenance costs. The filing also (a) increased depreciation expense due to the decrease in the average remaining life of the Welsh Plant to account for the change in the retirement date of the Welsh Plant Unit 2 from 2040 to 2016, (b) proposed increased vegetation management expenditures and (c) included a return on and of the Stall Unit as of December 2011 and associated operations and maintenance costs.

In September 2012, an Administrative Law Judge issued an order that granted the establishment of SWEPCo's existing rates as temporary rates beginning in late January 2013, subject to true-up to the final PUCT-approved rates.

In December 2012, several intervenors, including the PUCT staff, filed testimony that recommended an annual base rate increase between $16 million and $51 million based upon a return on common equity between 9.0% and 9.55%. In addition, two intervenors recommended that the Turk Plant be excluded from rate base. A decision from the PUCT is expected in the second quarter of 2013. If the PUCT does not approve full cost recovery of SWEPCo's assets, it would reduce future net income and cash flows and impact financial condition.

Louisiana 2012 Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share (approximately 29%) of the Turk Plant. In February 2013, a settlement was filed and a hearing was conducted. The settlement provided that SWEPCo would increase Louisiana total rates by approximately $2 million annually, effective March 2013, consisting of an increase in base rates of approximately $85 million annually offset by a decrease in fuel rates of approximately $83 million annually. The proposed March 2013 base rates are based on a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund based on the staff review of the cost of service and prudence review of the Turk Plant to be initiated by SWEPCo no later than May 2013. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover all non-fuel Turk Plant costs and a full weighted-average cost of capital return on the Turk Plant portion of rate base beginning January 2013. A decision from the LPSC is expected in the first quarter of 2013.

Flint Creek Plant Environmental Controls

In February 2012, SWEPCo filed a petition with the APSC seeking a declaratory order to install environmental controls at the Flint Creek Plant to comply with the standards established by the CAA. The estimated cost of the project is $408 million, excluding AFUDC and company overheads. As a joint owner of the Flint Creek Plant, SWEPCo's portion of those costs is estimated at $204 million. As of December 31, 2012, SWEPCo has incurred $11 million related to this project, including AFUDC and company overheads. The APSC staff and the Sierra Club filed testimony that recommended the APSC deny the requested declaratory order. A hearing is scheduled for March 2013. If SWEPCo is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

Louisiana 2010 Formula Rate Filing

In April 2010, SWEPCo filed its formula rate plan (FRP) which decreased annual Louisiana retail rates by $3 million effective August 2010, subject to refund. A settlement agreement was reached by the parties and orally approved by the LPSC in September 2012. A reserve recorded in the second quarter of 2012 was increased by an immaterial amount to cover the $3 million refund approved by the LPSC in the settlement agreement. The refund began in October 2012 and will occur over a twelve-month period.

APCo Rate Matters

Plant Transfers

In October 2012, the AEP East Companies submitted several filings with the FERC. See the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters. In December 2012, APCo and WPCo filed requests with the Virginia SCC and the WVPSC for approval to transfer at net book value to APCo a two-thirds interest in Amos Plant, Unit 3 and a one-half interest in the Mitchell Plant, comprising 1,647 MW of average annual generating capacity presently owned by OPCo. Hearings at the Virginia SCC and the WVPSC are scheduled for April 2013 and July 2013, respectively. If the transfers are approved, APCo and WPCo anticipate seeking cost recovery when they file their next base rate cases.

Virginia Fuel Filing

In April 2012, APCo filed an application with the Virginia SCC for an annual increase in fuel revenues of $117 million to be effective June 2012. The filing included forecasted costs for the 15-month period ended August 2013 and requested recovery of APCo's anticipated unrecovered fuel balance as of May 2012 over a two-year period commencing in June 2012. The non-incremental portion of APCo's forecasted and deferred wind purchased power costs were reflected in APCo's filing. In June 2012, the Virginia SCC approved the application as filed.

Environmental Rate Adjustment Clause (Environmental RAC)

In November 2011, the Virginia SCC issued an order which approved APCo's Environmental RAC recovery of $30 million to be collected over one year beginning in February 2012 but denied recovery of certain environmental costs. As a result, in 2011, APCo recorded a pretax write-off of $31 million on the statement of income related to environmental compliance costs incurred from January 2009 through December 2010. APCo appealed the Virginia SCC decision to the Supreme Court of Virginia. In November 2012, the Supreme Court of Virginia issued an order which allowed APCo to recover an additional $6 million of 2009 and 2010 actual Environmental RAC costs and affirmed the portion of the November 2011 order that denied recovery of certain environmental costs. The Virginia SCC issued an order in December 2012 which permitted APCo to extend the current Environmental RAC surcharge for the months of February and March 2013 in order to collect the $6 million.

Generation Rate Adjustment Clause (Generation RAC)

In January 2012, the Virginia SCC issued a Generation RAC order which allowed APCo to recover $26 million annually, effective March 2012, related to recovery of the Dresden Plant. APCo filed with the Virginia SCC to continue the current Generation RAC rate to recover costs of the Dresden Plant through February 2014. In December 2012, the Virginia SCC granted APCo's application as filed and required APCo to submit a new Generation RAC filing in March 2013.

APCo IGCC Plant

As of December 31, 2012, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to its West Virginia jurisdiction, approximately $2 million applicable to its FERC jurisdiction and approximately $9 million applicable to its Virginia jurisdiction. If the costs are not recoverable, it would reduce future net income and cash flows and impact financial condition.

APCo's and WPCo's Expanded Net Energy Charge (ENEC) Filing

In March 2012, West Virginia passed securitization legislation, which allows the WVPSC to establish a regulatory framework to securitize certain deferred ENEC balances and other ENEC related assets. Also in March 2012, APCo and WPCo filed their ENEC application with the WVPSC for the fourth year of a four-year phase-in plan which requested no change in ENEC rates if the WVPSC issues a financing order allowing securitization of the under-recovered ENEC deferral and other ENEC-related assets. If the financing order is not issued, APCo and WPCo requested that recovery of these costs be allowed in current rates.

In July 2012, the WVPSC issued an order that approved a settlement agreement which recommended no change in total ENEC rates but reflected a $24 million increase in the construction surcharge and a $24 million decrease in ENEC rates. In August 2012, APCo and WPCo filed with the WVPSC a request for a financing order to securitize a total of $422 million related to the December 2011 under-recovered ENEC deferral balance including other ENEC-related assets of $13 million and related future financing costs of $7 million. Upon completion of the securitization, APCo would offset its current ENEC rates by an amount to recover the securitized balance over the securitization period. In January 2013, intervenors filed testimony that recommended securitization of approximately $370 million. The differences between APCo's and WPCo's request and the intervenors' testimony represent previously approved ENEC-related deferred amounts being recovered in the ENEC over extended periods, various amounts deferred subsequent to the 2011 securitization period and related future securitization financing costs. As of December 31, 2012, APCo's ENEC under-recovery balance of $299 million, net of 2012 over-recovery, was recorded in Regulatory Assets on the balance sheet, excluding $4 million of unrecognized equity carrying costs and $12 million of other ENEC-related assets. APCo and WPCo are currently in settlement discussions with intervenors.

WPCo Merger with APCo

In December 2011, APCo and WPCo filed an application with the WVPSC requesting approval to merge WPCo into APCo. In December 2012, APCo and WPCo filed merger applications with the Virginia SCC and the FERC. A hearing at the Virginia SCC is scheduled for April 2013.

PSO Rate Matters

PSO 2008 Fuel and Purchased Power

In 2009, the OCC initiated a proceeding to review PSO's fuel and purchased power adjustment clause for the calendar year 2008 and also initiated a prudence review of the related costs. In October 2012, the OCC issued a final order that found PSO's fuel and purchased power costs were prudently incurred without any disallowance and that PSO's shareholder's portion of off-system sales margins would remain at 25%.

Oklahoma Environmental Compliance Plan

In September 2012, PSO filed an environmental compliance plan with the OCC reflecting the retirement of Northeastern Station (NES) Unit 4 in 2016 and additional environmental controls on NES Unit 3 to continue operations through 2026. The plan requested approval for (a) cost recovery through base rates by 2026 of an estimated $256 million of new environmental investment that will be incurred prior to 2016 at NES Unit 3, (b) cost recovery through 2026 of NES Units 3 and 4 net book value (combined net book value of the two units is $234 million as of December 31, 2012), (c) cost recovery through base rates of an estimated $83 million of new investment incurred through 2016 at various gas units and (d) a new 15-year purchase power agreement (PPA) with a nonaffiliated entity, effective in 2016, with cost recovery through a rider, including an annual earnings component of $3 million. Although the environmental compliance plan does not seek to put any new costs into rates at this time, PSO anticipates seeking cost recovery when filing its next base rate case, which is expected to occur no later than 2014.

In January 2013, testimony filed by the OCC staff and the Oklahoma Office of the Attorney General generally agreed with PSO's plan, although they recommended no earnings component on the PPA and to delay final decisions on parts of the plan including cost recovery of NES Unit 3 and any increases in fuel costs due to reductions in the output of energy from NES Unit 3 beginning in 2021. The testimony recommended that cost recovery could extend past 2026 on parts of the plan and recommended a $175 million cost cap on NES Unit 3 environmental investment.

Also, an intervenor representing some of PSO's large industrial users opposed virtually all of PSO's plan, including recommending no cost recovery of NES Units 3 and 4 book value amounts not recovered at the time of their retirement and no recovery of the PPA costs, including earnings on the PPA. A hearing is scheduled for April 2013.

I&M Rate Matters

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 $149 million net annual increase reflects an increase in base rates of $178 million offset by proposed corresponding reductions of $13 million to the off-system sales sharing rider, $9 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The request included an increase in depreciation rates that would result in an increase of approximately $25 million in annual depreciation expense. Included in the depreciation rates increase was a decrease in the average remaining life of Tanners Creek Plant to account for the change in the retirement date of Tanners Creek Plant, Units 1-3 from 2020 to 2014. In May 2012, I&M filed rebuttal testimony which changed the retirement date for Tanners Creek Plant, Units 1-3 to 2015 and supported an increase of $170 million in base rates, excluding reductions to certain riders.

In February 2013, the IURC issued an order that granted an $85 million annual increase in base rates based upon a return on common equity of 10.2%, effective March 2013. The $85 million annual increase in base rates will be offset by corresponding reductions of $5 million to the off-system sales sharing rider, $11 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The IURC granted the requested increase in depreciation rates, modified the shareholder's portion of off-system sales margins to 50% below and above the $27 million imbedded in base rates, established a capacity tracker and established a major storm damage restoration reserve.

Cook Plant Life Cycle Management Project

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its licensed life. The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC.

In Indiana, I&M requested recovery of certain project costs, including interest, through a new rider effective January 2013. In Michigan, I&M requested that the MPSC approve a Certificate of Need and authorize I&M to defer, on an interim basis, incremental depreciation and related property tax costs, including interest, along with study, analysis and development costs until the applicable LCM costs are included in I&M's base rates. As of December 31, 2012, I&M has incurred $176 million related to the LCM Project, including AFUDC.

In August 2012, intervenors filed testimony in Indiana. The Indiana Michigan Power Company Industrial Group recommended that I&M recover $229 million in a rider with the remaining costs to be requested in future base rate cases. The Indiana Office of Utility Consumer Counselor (OUCC) recommended a maximum of $408 million of LCM project costs be recovered in a rider, and a maximum of $299 million for projects the OUCC believes are not related to LCM to be recovered in future base rates. The IURC held a hearing in January 2013.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project with total costs of $851 million (Michigan jurisdictional share is approximately 15%) for the period 2013 through 2018. The order provided that depreciation, property taxes and a return using the overall rate of return approved in I&M's last Michigan base rate case related to the 2013 through 2018 LCM Project costs can be deferred until these costs are included in rates. The order excluded from the CON $176 million of LCM costs spent prior to 2013 as $39 million was included in the determination of Michigan base rates, effective April 2012, and the remaining $137 million in CWIP will be requested in a future base rate case. The order also excluded $142 million of future LCM costs, which if incurred, will be requested in a future base rate case. Under Michigan law, the approved CON amount is eligible for a cost increase allowance of 10%, up to $85 million, of the approved project costs in the event project costs exceed the approved level of costs.

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

Rockport Plant Environmental Controls

I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit one unit at its Rockport Plant with environmental controls estimated to cost $1.4 billion to comply with new requirements. AEGCo and I&M jointly own Unit 1 and jointly lease Unit 2 of the Rockport Plant. I&M is also evaluating options related to the maturity of the lease for Rockport Plant Unit 2 in 2022 and continues to investigate alternative compliance technologies for these units as part of its overall compliance strategy. As of December 31, 2012, I&M has incurred $36 million related to these environmental controls, including AFUDC. If I&M is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

In February 2013, I&M filed a motion with the IURC to dismiss its request for approval of a CPCN for environmental controls after modification to the NSR consent decree. Under the terms of the NSR consent decree modification, the units of Rockport Plant will be equipped with dry sorbent injection systems in 2013 and have options to retrofit additional SO_2 controls, refuel, repower or retire in 2025 and 2028.

FERC Rate Matters

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund – Affecting APCo, I&M and OPCo

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. APCo's, I&M's and OPCo's portions of recognized gross SECA revenues are as follows:

Company	(in millions)
APCo	$ 70.2
I&M	41.3
OPCo	92.1

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. In August 2010, the affected companies, including the AEP East Companies, filed a compliance filing with the FERC. The AEP East Companies provided reserves for net refunds for SECA settlements. The AEP East Companies settled with various parties prior to the FERC compliance filing and entered into additional settlements subsequent to the compliance filing being filed at the FERC. Based on the analysis of the May 2010 order, the compliance filing and recent settlements, management believes that the reserve is adequate to pay the refunds, including interest, and any remaining exposure beyond the reserve is immaterial.

Corporate Separation and Termination of Interconnection Agreement – Affecting APCo, I&M and OPCo

In October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generation assets from its distribution and transmission operations. The filings requested approval to transfer at net book value approximately 9,200 MW of OPCo-owned generation assets to a new wholly-owned company, AEPGenCo. The AEP East Companies also requested FERC approval to transfer at net book value OPCo's current two-thirds ownership (867 MW) in Amos Plant, Unit 3 to APCo and transfer at net book value OPCo's Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each). Additionally, the AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement among APCo, I&M and KPCo. Intervenors have opposed several of these filings. The AEP East Companies have responded and continue to pursue approvals from the FERC. A decision from the FERC is expected in mid-2013. Similar filings have been made at the Virginia SCC and the WVPSC. See the "Plant Transfers" section of APCo Rate Matters.

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

3. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	APCo December 31, 2012	APCo December 31, 2011	APCo Remaining Recovery Period	I&M December 31, 2012	I&M December 31, 2011	I&M Remaining Recovery Period
	(in thousands)			(in thousands)		
Current Regulatory Assets						
Under-recovered Fuel Costs - earns a return	$ 74,906	$ 41,105	1 year	$ 3,029	$ -	1 year
Under-recovered Fuel Costs - does not earn a return	-	-		1,647	8,876	1 year
Total Current Regulatory Assets	$ 74,906	$ 41,105		$ 4,676	$ 8,876	
Noncurrent Regulatory Assets						
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:						
Regulatory Assets Currently Not Earning a Return						
Storm Related Costs	$ 94,458	$ -		$ -	$ -	
Virginia Environmental Rate Adjustment Clause	29,320	17,950		-	-	
Mountaineer Carbon Capture and Storage Product Validation Facility	14,155	14,155		-	-	
Dresden Plant Operating Costs	8,758	-		-	-	
Deferred Wind Power Costs	5,143	38,192		-	-	
Transmission Agreement Phase-In	2,992	1,925		-	-	
Mountaineer Carbon Capture and Storage Commercial Scale Facility	1,287	1,335		1,380	1,680	
Special Rate Mechanism for Century Aluminum	-	12,811		-	-	
Litigation Settlement	-	-		11,098	10,803	
Other Regulatory Assets Not Yet Being Recovered	1,447	1,010		786	-	
Total Regulatory Assets Not Yet Being Recovered	157,560	87,378		13,264	12,483	
Regulatory assets being recovered:						
Regulatory Assets Currently Earning a Return						
West Virginia Expanded Net Energy Charge	272,783	326,766	(a)	-	-	
Storm Related Costs	21,371	25,225	6 years	-	-	
Unamortized Loss on Reacquired Debt	12,969	13,592	30 years	15,871	17,355	20 years
RTO Formation/Integration Costs	4,370	5,194	7 years	3,229	3,858	7 years
Customer Choice Implementation Costs	-	-		1,493	4,680	1 year
Regulatory Assets Currently Not Earning a Return						
Income Taxes, Net	525,549	512,025	26 years	222,252	188,749	36 years
Pension and OPEB Funded Status	312,645	362,322	12 years	220,797	291,392	12 years
Virginia Transmission Rate Adjustment Clause	32,992	19,553	2 years	-	-	
West Virginia Expanded Net Energy Charge	25,932	31,979	(a)	-	-	
Postemployment Benefits	22,663	22,645	5 years	8,897	9,137	5 years
Storm Related Costs	13,712	16,324	6 years	-	-	
Deferred Restructuring Costs	10,531	12,537	6 years	3,688	4,952	3 years
Asset Retirement Obligation	8,489	10,524	5 years	808	3,396	8 years
Virginia Environmental Rate Adjustment Clause	8,347	23,844	1 year	-	-	
Virginia Generation Rate Adjustment Clause	3,469	-	1 year	-	-	
Deferred Wind Power Costs	915	6,284	1 year	-	-	
Virginia Environmental and Reliability Costs	560	3,838	1 year	-	-	
Cook Nuclear Plant Refueling Outage Levelization	-	-		26,652	40,551	3 years
Deferred PJM Fees	-	-		13,998	21,746	2 years
River Transportation Division Expenses	-	-		4,576	1,899	1 year
Peak Demand Reduction/Energy Efficiency	-	-		2,608	1,387	1 year
Other Regulatory Assets Being Recovered	847	1,163	various	1,886	1,394	various
Total Regulatory Assets Being Recovered	1,278,144	1,393,815		526,755	590,496	
Total Noncurrent Regulatory Assets	$ 1,435,704	$ 1,481,193		$ 540,019	$ 602,979	

(a) Request for securitization is pending from the WVPSC to recover $422 million as securitized transition assets from ratepayers over the securitization bond period.

Regulatory Liabilities:	APCo December 31, 2012	APCo December 31, 2011	APCo Remaining Refund Period	I&M December 31, 2012	I&M December 31, 2011	I&M Remaining Refund Period
	(in thousands)			(in thousands)		
Current Regulatory Liabilities						
Over-recovered Fuel Costs - pays a return	$ -	$ -		$ -	$ 25	
Total Current Regulatory Liabilities	$ -	$ -		$ -	$ 25	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits						
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	249	327		124	136	
Total Regulatory Liabilities Not Yet Being Paid	249	327		124	454	
Regulatory liabilities being paid:						
Regulatory Liabilities Currently Paying a Return						
Asset Removal Costs	552,590	526,885	(a)	381,116	362,134	(a)
Deferred Investment Tax Credits	2,823	3,231	48 years	-	-	
Regulatory Liabilities Currently Not Paying a Return						
Deferred State Income Tax Coal Credits	29,296	28,727	10 years	-	-	
Unrealized Gain on Forward Commitments	21,433	15,597	5 years	19,872	21,785	5 years
Deferred Investment Tax Credits	382	1,214	3 years	48,130	52,633	25 years
Peak Demand Reduction/Energy Efficiency	907	811	1 year	11,080	11,078	1 year
Excess Asset Retirement Obligations for Nuclear Decommissioning Liability	-	-		435,717	377,162	(b)
Spent Nuclear Fuel Liability	-	-		42,898	42,603	(b)
Off-system Sales Margin Sharing	-	-		7,611	5,892	1 year
Indiana Clean Coal Technology Rider	-	-		774	1,242	1 year
Other Regulatory Liabilities Being Paid	-	-		970	219	various
Total Regulatory Liabilities Being Paid	607,431	576,465		948,168	874,748	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 607,680	$ 576,792		$ 948,292	$ 875,202	

(a) Relieved as removal costs are incurred.
(b) Relieved when plant is decommissioned.

	OPCo		
	December 31,		Remaining Recovery Period
Regulatory Assets:	**2012**	**2011**	
	(in thousands)		
Noncurrent Regulatory Assets			
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:			
Regulatory Assets Currently Earning a Return			
Economic Development Rider	$ 13,213	$ 12,572	
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	61,828	8,375	
Ormet Delayed Payment Arrangement	5,453	-	
Other Regulatory Assets Not Yet Being Recovered	30	-	
Total Regulatory Assets Not Yet Being Recovered	80,524	20,947	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Ohio Fuel Adjustment Clause	518,595	506,607	6 years
Ohio Deferred Asset Recovery Rider	152,039	173,274	6 years
Ohio Capacity Deferral	65,818	-	6 years
Transmission Cost Recovery Rider	49,391	28,404	3 years
Unamortized Loss on Reacquired Debt	13,215	14,552	26 years
RTO Formation/Integration Costs	6,594	7,836	7 years
Economic Development Rider	5,488	11,738	1 year
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	309,685	389,712	12 years
Income Taxes, Net	190,685	190,981	21 years
Distribution Decoupling	16,198	-	2 years
Postemployment Benefits	7,658	8,669	5 years
Partnership with Ohio Contribution	2,405	3,400	3 years
Distribution Investment Rider	1,304	-	1 year
Unrealized Loss on Forward Commitments	810	9,930	1 year
Enhanced Service Reliability Plan	557	4,454	1 year
Total Regulatory Assets Being Recovered	1,340,442	1,349,557	
Total Noncurrent Regulatory Assets	$ 1,420,966	$ 1,370,504	

Regulatory Liabilities:	OPCo December 31, 2012	OPCo December 31, 2011	Remaining Refund Period
	(in thousands)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - does not pay a return	$ 14,848	$ -	1 year
Total Current Regulatory Liabilities	$ 14,848	$ -	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities not yet being paid:			
Regulatory Liabilities Currently Paying a Return			
IGCC Preconstruction Costs	$ 4,411	$ 4,196	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Not Yet Being Paid	216	216	
Total Regulatory Liabilities Not Yet Being Paid	4,627	4,412	
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	416,461	251,100	(a)
Deferred Investment Tax Credits	322	549	9 years
Economic Development Rider	-	2,428	
Transmission Cost Recovery Rider	-	542	
Regulatory Liabilities Currently Not Paying a Return			
Peak Demand Reduction/Energy Efficiency	12,596	19,124	2 years
Deferred Investment Tax Credits	11,321	12,944	12 years
Over-recovery of Costs Related to gridSMART®	3,501	7,504	2 years
Low Income Customers/Economic Recovery	2,243	2,521	3 years
Total Regulatory Liabilities Being Paid	446,444	296,712	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 451,071	$ 301,124	

(a) Relieved as removal costs are incurred.

Regulatory Assets:	PSO December 31, 2012	PSO December 31, 2011	PSO Remaining Recovery Period	SWEPCo December 31, 2012	SWEPCo December 31, 2011	SWEPCo Remaining Recovery Period
	(in thousands)			(in thousands)		
Current Regulatory Assets						
Under-recovered Fuel Costs - earns a return	$ -	$ 4,313		$ 8,527	$ 10,843	1 year
Total Current Regulatory Assets	$ -	$ 4,313		$ 8,527	$ 10,843	
Noncurrent Regulatory Assets						
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:						
Regulatory Assets Currently Not Earning a Return						
Rate Case Expense	$ -	$ -		$ 4,517	$ -	
Mountaineer Carbon Capture and Storage Commercial Scale Facility	-	-		2,295	2,380	
Other Regulatory Assets Not Yet Being Recovered	423	-		2,188	1,699	
Total Regulatory Assets Not Yet Being Recovered	423	-		9,000	4,079	
Regulatory assets being recovered:						
Regulatory Assets Currently Earning a Return						
Storm Related Costs	14,172	38,659	1 year	337	965	1 year
Unamortized Loss on Reacquired Debt	10,923	12,538	20 years	9,379	10,768	31 years
Red Rock Generating Facility	9,954	10,180	44 years	-	-	
Acquisition of Valley Electric Membership Corporation (VEMCO)	-	-		6,443	8,789	3 years
Regulatory Assets Currently Not Earning a Return						
Pension and OPEB Funded Status	133,404	178,295	12 years	143,226	176,587	12 years
Vegetation Management	13,388	11,196	1 year	-	-	
Peak Demand Reduction/Energy Efficiency	6,248	4,394	1 year	1,467	1,284	1 year
Unrealized Loss on Forward Commitments	5,347	1,706	1 year	427	4,684	1 year
Deferral of Major Generation Overhauls	4,533	6,133	5 years	-	-	
Income Taxes, Net	3,785	2,923	34 years	230,220	178,826	40 years
Rate Case Expense	-	216		1,168	3,602	1 year
Dolet Hills Deferred Fuel	-	-		1,048	1,886	2 years
Storm Related Costs	-	-		400	2,556	1 year
Other Regulatory Assets Being Recovered	151	305	various	163	250	various
Total Regulatory Assets Being Recovered	201,905	266,545		394,278	390,197	
Total Noncurrent Regulatory Assets	$ 202,328	$ 266,545		$ 403,278	$ 394,276	

	PSO			SWEPCo		
	December 31,		Remaining Refund	December 31,		Remaining Refund
	2012	2011	Period	2012	2011	Period
Regulatory Liabilities:	(in thousands)			(in thousands)		
Current Regulatory Liabilities						
Over-recovered Fuel Costs - pays a return	$ 7,945	$ -	1 year	$ 16,761	$ 5,032	1 year
Total Current Regulatory Liabilities	$ 7,945	$ -		$ 16,761	$ 5,032	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits						
Regulatory liabilities not yet being paid:						
Regulatory Liabilities Currently Paying a Return						
Louisiana Refundable Construction Financing Costs	$ -	$ -		$ 96,094	$ 52,594	
Regulatory Liabilities Currently Not Paying a Return						
Over-recovery of Costs Related to gridSMART®	3,964	4,232		-	-	
Storm Related Costs	3,207	2,248		-	-	
Other Regulatory Liabilities Not Yet Being Paid	1,613	-		-	806	
Total Regulatory Liabilities Not Yet Being Paid	8,784	6,480		96,094	53,400	
Regulatory liabilities being paid:						
Regulatory Liabilities Currently Paying a Return						
Asset Removal Costs	280,446	280,491	(a)	362,838	353,067	(a)
Excess Earnings	-	-		2,975	3,047	41 years
Other Regulatory Liabilities Being Paid	-	-		838	1,305	various
Regulatory Liabilities Currently Not Paying a Return						
Deferred Investment Tax Credits	42,345	40,310	36 years	12,769	13,318	26 years
Base Load Purchase Power Contract	8,484	-	1 year	-	-	
Peak Demand Reduction/Energy Efficiency	2,915	6,444	1 year	-	-	
Vegetation Management	-	-		130	3,158	1 year
Other Regulatory Liabilities Being Paid	1,843	1,087	various	827	1,276	various
Total Regulatory Liabilities Being Paid	336,033	328,332		380,377	375,171	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 344,817	$ 334,812		$ 476,471	$ 428,571	

(a) Relieved as removal costs are incurred.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The Registrant Subsidiaries are subject to certain claims and legal actions arising in their ordinary course of business. In addition, their business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements.

COMMITMENTS

Construction and Commitments – Affecting APCo, I&M, OPCo, PSO and SWEPCo

The Registrant Subsidiaries have substantial construction commitments to support their operations and environmental investments. In managing the overall construction program and in the normal course of business, the Registrant Subsidiaries contractually commit to third-party construction vendors for certain material purchases and other construction services. The following table shows the forecasted construction expenditures, excluding equity AFUDC and capitalized interest, by Registrant Subsidiary for 2013:

Company	Forecasted Construction Expenditures
	(in millions)
APCo	$ 370
I&M	484
OPCo	617
PSO	295
SWEPCo	398

The Registrant Subsidiaries also purchase fuel, materials, supplies, services and property, plant and equipment under contract as part of their normal course of business. Certain supply contracts contain penalty provisions for early termination.

The following tables summarize the Registrant Subsidiaries' actual contractual commitments as of December 31, 2012:

Contractual Commitments - APCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 611,664	$ 711,277	$ 544,598	$ 553,315	$ 2,420,854
Energy and Capacity Purchase Contracts (b)	32,293	66,034	67,882	586,336	752,545
Construction Contracts for Capital Assets (c)	13,094	-	-	-	13,094
Total	$ 657,051	$ 777,311	$ 612,480	$ 1,139,651	$ 3,186,493

Contractual Commitments - I&M	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 330,157	$ 535,223	$ 336,830	$ 447,930	$ 1,650,140
Energy and Capacity Purchase Contracts (b)	89,128	178,501	178,543	609,371	1,055,543
Construction Contracts for Capital Assets (c)	6,389	-	-	-	6,389
Total	$ 425,674	$ 713,724	$ 515,373	$ 1,057,301	$ 2,712,072

Contractual Commitments - OPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 1,167,631	$ 2,012,580	$ 1,542,218	$ 1,368,019	$ 6,090,448
Energy and Capacity Purchase Contracts (b)	45,009	91,997	94,290	920,573	1,151,869
Construction Contracts for Capital Assets (c)	22,407	-	-	-	22,407
Total	$ 1,235,047	$ 2,104,577	$ 1,636,508	$ 2,288,592	$ 7,264,724

Contractual Commitments - PSO	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 119,855	$ 140,535	$ 113,035	$ 197,788	$ 571,213
Energy and Capacity Purchase Contracts (b)	69,216	141,389	145,439	528,899	884,943
Construction Contracts for Capital Assets (c)	9,554	-	-	-	9,554
Total	$ 198,625	$ 281,924	$ 258,474	$ 726,687	$ 1,465,710

Contractual Commitments - SWEPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 296,426	$ 487,711	$ 316,753	$ 340,969	$ 1,441,859
Energy and Capacity Purchase Contracts (b)	19,714	39,252	40,656	244,199	343,821
Construction Contracts for Capital Assets (c)	21,898	-	-	-	21,898
Total	$ 338,038	$ 526,963	$ 357,409	$ 585,168	$ 1,807,578

(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 – Affecting APCo, I&M, OPCo and SWEPCo

Certain Registrant Subsidiaries enter into standby letters of credit with third parties. These letters of credit are issued in the ordinary course of business and cover items such as insurance programs, security deposits and debt service reserves.

AEP has two credit facilities totaling $3.25 billion, under which up to $1.35 billion may be issued as letters of credit. In February 2013, AEP increased and extended the $1.5 billion credit facility due in June 2015 to $1.75 billion due in June 2016, extended the $1.75 billion credit facility due in July 2016 to July 2017 and issued a $1 billion interim credit facility due in May 2015 to fund certain OPCo maturities. As of December 31, 2012, the maximum future payments for letters of credit issued under the credit facilities were as follows:

Company	Amount (in thousands)	Maturity
I&M	$ 150	March 2013
OPCo	2,102	June 2013
SWEPCo	4,448	March 2013

The Registrant Subsidiaries have $357 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $361 million detailed in the table below. In February 2013, APCo and I&M extended certain bilateral letters of credit due in March 2013 to March 2015, while OPCo extended its bilateral letter of credit due in March 2013 to July 2014.

Company	Pollution Control Bonds	Bilateral Letters of Credit	Maturity of Bilateral Letters of Credit
	(in thousands)		
APCo	$ 229,650	$ 232,293	March 2013 to March 2014
I&M	77,000	77,886	March 2013
OPCo	50,000	50,575	March 2013

Guarantees of Third-Party Obligations – Affecting SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $115 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study completed in 2010, it is estimated the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately $58 million. As of December 31, 2012, SWEPCo has collected approximately $59 million through a rider for final mine closure and reclamation costs, of which $18 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $41 million is recorded in Asset Retirement Obligations on SWEPCo's balance sheets.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs to customers through its fuel clause.

Indemnifications and Other Guarantees – Affecting APCo, I&M, OPCo, PSO and SWEPCo

Contracts

The Registrant Subsidiaries enter 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, 2012, 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 power purchase and sale activity pursuant to the SIA. PSO and SWEPCo are jointly and severally liable for activity conducted by AEPSC on behalf of PSO and SWEPCo related to power purchase and sale activity pursuant to the SIA.

Lease Obligations

Certain Registrant Subsidiaries lease certain equipment under master lease agreements. See "Master Lease Agreements" and "Railcar Lease" sections of Note 11 for disclosure of lease residual value guarantees.

ENVIRONMENTAL CONTINGENCIES

Carbon Dioxide Public Nuisance Claims – Affecting APCo, I&M, OPCo, PSO and SWEPCo

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011. Plaintiffs refiled their complaint in federal district court. The court ordered all defendants to respond to the refiled complaints in October 2011. In March 2012, the court granted the defendants' motion for dismissal on several grounds, including the doctrine of collateral estoppel and the applicable statute of limitations. Plaintiffs appealed the decision to the Fifth Circuit Court of Appeals. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Alaskan Villages' Claims – Affecting APCo, I&M, OPCo, PSO and SWEPCo

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. In September 2012, the Ninth Circuit Court of Appeals affirmed the trial court's decision, holding that the CAA displaced Kivalina's claims for damages. Plaintiffs' petition for rehearing by the full court was denied in November 2012, but the plaintiffs could seek further review in the U.S. Supreme Court. Management believes the action is without merit and will continue 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 – Affecting APCo, I&M, OPCo, PSO and SWEPCo

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. The Registrant Subsidiaries currently incur 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. As of December 31, 2012, APCo is named as a Potentially Responsible Party (PRP) for two site and OPCo is named a PRP for three sites by the Federal EPA. There are seven additional sites for which APCo, I&M, OPCo, and SWEPCo have received information requests which could lead to PRP designation. I&M has also been named potentially liable at two sites under state law including the I&M site discussed in the next paragraph. SWEPCo has also been named potentially liable at one site under state law. In those instances where the Registrant Subsidiaries have been named a PRP or defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ. I&M's reserve is approximately $10 million. As the remediation work is completed, I&M's cost may change as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation required by the MDEQ. Management cannot predict the amount of additional cost, if any.

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

NUCLEAR CONTINGENCIES – AFFECTING I&M

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

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The most recent decommissioning cost study was performed in 2012. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste ranges from $1.3 billion to $1.7 billion in 2012 nondiscounted dollars. The wide range in estimated costs is caused by variables in assumptions. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were $14 million, $14 million and $14 million for the years ended December 31, 2012, 2011 and 2010, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2012 and 2011, the total decommissioning trust fund balance was $1.4 billion and $1.3 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including interest, unrealized gains and losses and expenses of the trust funds) increase or decrease the recorded liability.

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

SNF Disposal

The Federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWh for fuel consumed after April 6, 1983 at the Cook Plant is being collected from customers and remitted to the U.S. Treasury. As of December 31, 2012 and 2011, 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 $308 million, respectively, to pay the fee are recorded as part of Spent Nuclear Fuel and Decommissioning Trusts. 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 $20 million and $14 million in 2012 and 2011, respectively, 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 costs for dry cask storage. As of December 31, 2012, I&M has deferred $32 million in Prepayments and Other Current Assets and $13 million in Deferred Charges and Other Noncurrent Assets on the balance sheet of dry cask storage and related operation and maintenance costs for recovery under this agreement.

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

Nuclear Incident Liability

I&M carries insurance coverage for 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 $40 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, it could reduce future net income and cash flows and impact financial condition.

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. 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. In February 2013, management signed an agreement and received payment from NEIL to settle the remaining insurance claims. The settlement did not have a material impact on net income, cash flows or financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses – Affecting APCo, I&M, OPCo, PSO and SWEPCo

The Registrant Subsidiaries maintain 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 the Registrant Subsidiaries. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

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

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

5. <u>ACQUISITIONS AND IMPAIRMENTS</u>

ACQUISITIONS

<u>2011</u>

Dresden Plant – Affecting APCo

In August 2011, APCo purchased the partially completed Dresden Plant from AEGCo, at cost, for $302 million. The Dresden Plant was completed and placed in service in January 2012. The Dresden Plant is located near Dresden, Ohio and is a natural gas, combined cycle power plant with a generating capacity of 608 MW.

<u>2010</u>

Valley Electric Membership Corporation – Affecting SWEPCo

In October 2010, SWEPCo purchased certain transmission and distribution assets of Valley Electric Membership Corporation (VEMCO) for approximately $102 million and began serving VEMCO's 30,000 customers in Louisiana.

IMPAIRMENTS

__2012__

Beckjord Plant Unit 6, Conesville Plant Unit 3, Kammer Plant Units 1-3, Muskingum River Plant Units 1-4, Sporn Plant Units 2 and 4 and Picway Plant Unit 5 – Affecting OPCo

In October 2012, management filed applications with the FERC proposing to terminate the Interconnection Agreement and seeking to complete the corporate separation of OPCo's generation assets. Based on the intention to terminate the Interconnection Agreement and the FERC filing, management performed an evaluation of the recoverability of generation assets. As a result, in November 2012, management, using generating unit specific estimated future cash flows, concluded that OPCo had a material impairment of certain generation assets. Under a market-based value approach, using level 3 unobservable inputs, management determined that the fair value of these generating units was zero based on the lack of installed environmental control equipment and the nature and condition of these generating units. In the fourth quarter of 2012, OPCo recorded a pretax impairment of $287 million in Asset Impairments and Other Related Charges on the statement of income related to Beckjord Plant Unit 6, Conesville Plant Unit 3, Kammer Plant Units 1-3, Muskingum River Plant Units 1-4, Sporn Plant Units 2 and 4 and Picway Plant Unit 5 generating units which includes $13 million of related material and supplies inventory.

Turk Plant – Affecting SWEPCo

In 2012, SWEPCo recorded a pretax write-off of $13 million in Asset Impairments and Other Related Charges on the statement of income related to unrecoverable construction costs subject to the Texas capital costs cap portion of the Turk Plant.

__2011__

Turk Plant – Affecting SWEPCo

In the fourth quarter of 2011, SWEPCo recorded a pretax write-off of $49 million in Asset Impairments and Other Related Charges on the statement of income related to the Texas jurisdictional portion of the Turk Plant as a result of the November 2011 Texas Court of Appeals decision upholding the Texas capital cost cap.

Muskingum River Plant Unit 5 FGD Project (MR5) – Affecting OPCo

In September 2011, subsequent to the stipulation agreement filed with the PUCO, management determined that OPCo was not likely to complete the previously suspended MR5 project and that the project's preliminary engineering costs were no longer probable of being recovered. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $42 million in Asset Impairments and Other Related Charges on the statement of income.

Sporn Plant Unit 5 – Affecting OPCo

In the third quarter of 2011, management decided to no longer offer the output of Sporn Unit 5 into the PJM market. Sporn Unit 5 is not expected to operate in the future, resulting in the removal of Sporn Unit 5 from the Interconnection Agreement. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $48 million in Asset Impairments and Other Related Charges on the statement of income.

6. BENEFIT PLANS

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

The Registrant Subsidiaries participate in an AEP sponsored qualified pension plan and two unfunded nonqualified pension plans. Substantially all employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. The Registrant Subsidiaries also participate in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees.

Due to the Registrant Subsidiaries' participation in AEP's benefits plans, the assumptions used by the actuary and the accounting for the plans by each subsidiary are the same. This section details the assumptions that apply to all Registrant Subsidiaries and the rate of compensation increase for each subsidiary.

The Registrant Subsidiaries recognize the funded status associated with defined benefit pension and OPEB plans in their balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. The Registrant Subsidiaries recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. The Registrant Subsidiaries record 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 the Registrant Subsidiaries' benefit obligations are shown in the following tables:

	Pension Plans		Other Postretirement Benefit Plans	
Assumption	**2012**	**2011**	**2012**	**2011**
Discount Rate	3.95 %	4.55 %	3.95 %	4.75 %

	Pension Plans	
Assumption - Rate of Compensation Increase (a)	**2012**	**2011**
APCo	4.70 %	4.65 %
I&M	5.00 %	4.90 %
OPCo	5.00 %	4.95 %
PSO	4.90 %	4.85 %
SWEPCo	4.75 %	4.70 %

(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.

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

For 2012, 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 shown in the table above. The compensation increase rates reflect variations in each Registrant Subsidiary's population participating in the pension plan.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1 of each year used in the measurement of each Registrant Subsidiary's benefit costs are shown in the following tables:

	Pension Plans			Other Postretirement Benefit Plans		
Assumptions	2012	2011	2010	2012	2011	2010
Discount Rate	4.55 %	5.05 %	5.60 %	4.75 %	5.25 %	5.85 %
Expected Return on Plan Assets	7.25 %	7.75 %	8.00 %	7.25 %	7.50 %	8.00 %

	Pension Plans		
Assumption - Rate of Compensation Increase	2012	2011	2010
APCo	4.70 %	4.65 %	4.35 %
I&M	5.00 %	4.90 %	4.55 %
OPCo	5.00 %	4.95 %	4.70 %
PSO	4.90 %	4.85 %	4.60 %
SWEPCo	4.75 %	4.70 %	4.45 %

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 expected return on plan assets is the same for each Registrant Subsidiary.

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	2012	2011
Initial	7.00 %	7.50 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2020	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:

	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost:					
1% Increase	$ 3,845	$ 3,017	$ 5,347	$ 1,336	$ 1,547
1% Decrease	(3,029)	(2,390)	(4,206)	(1,059)	(1,227)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation:					
1% Increase	$ 26,416	$ 12,592	$ 34,018	$ 5,447	$ 6,008
1% Decrease	(20,173)	(9,529)	(25,950)	(4,113)	(4,537)

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. Management monitors the plans to control security diversification and ensure compliance with the investment policy. As of December 31, 2012, 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, 2012 and 2011

The following tables provide 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.

APCo

	Pension Plans		Other Postretirement Benefit Plans	
	2012	**2011**	**2012**	**2011**
Change in Benefit Obligation	(in thousands)			
Benefit Obligation as of January 1	$ 681,450	$ 652,219	$ 395,482	$ 383,152
Service Cost	7,565	7,199	5,387	4,983
Interest Cost	30,211	32,293	18,462	19,468
Actuarial Loss	43,341	29,137	31,776	41,306
Plan Amendment Prior Service Credit	-	-	(80,528)	(31,145)
Benefit Payments	(44,107)	(39,398)	(29,228)	(30,040)
Participant Contributions	-	-	5,826	6,005
Medicare Subsidy	-	-	1,813	1,753
Benefit Obligation as of December 31	$ 718,460	$ 681,450	$ 348,990	$ 395,482
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1	$ 570,756	$ 512,836	$ 229,735	$ 243,771
Actual Gain (Loss) on Plan Assets	69,686	36,970	44,919	(4,102)
Company Contributions	25,235	60,348	16,506	14,101
Participant Contributions	-	-	5,826	6,005
Benefit Payments	(44,107)	(39,398)	(29,228)	(30,040)
Fair Value of Plan Assets as of December 31	$ 621,570	$ 570,756	$ 267,758	$ 229,735
Underfunded Status as of December 31	$ (96,890)	$ (110,694)	$ (81,232)	$ (165,747)

I&M

	Pension Plans		Other Postretirement Benefit Plans	
	2012	**2011**	**2012**	**2011**
Change in Benefit Obligation	(in thousands)			
Benefit Obligation as of January 1	$ 581,677	$ 560,982	$ 277,353	$ 266,742
Service Cost	9,908	9,447	6,621	6,119
Interest Cost	26,245	27,726	12,785	13,610
Actuarial Loss	44,475	17,289	13,638	28,876
Plan Amendment Prior Service Credit	-	-	(78,851)	(24,846)
Benefit Payments	(43,332)	(33,767)	(18,394)	(18,387)
Participant Contributions	-	-	4,226	4,112
Medicare Subsidy	-	-	1,175	1,127
Benefit Obligation as of December 31	$ 618,973	$ 581,677	$ 218,553	$ 277,353
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1	$ 503,926	$ 451,688	$ 181,237	$ 188,690
Actual Gain (Loss) on Plan Assets	69,136	32,773	14,357	(3,946)
Company Contributions	22,296	53,232	12,702	10,768
Participant Contributions	-	-	4,226	4,112
Benefit Payments	(43,332)	(33,767)	(18,394)	(18,387)
Fair Value of Plan Assets as of December 31	$ 552,026	$ 503,926	$ 194,128	$ 181,237
Underfunded Status as of December 31	$ (66,947)	$ (77,751)	$ (24,425)	$ (96,116)

OPCo

	Pension Plans		Other Postretirement Benefit Plans	
	2012	2011	2012	2011
Change in Benefit Obligation	(in thousands)			
Benefit Obligation as of January 1	$ 1,020,890	$ 984,089	$ 519,892	$ 506,255
Service Cost	11,003	10,230	8,748	7,827
Interest Cost	45,194	48,350	24,189	25,497
Actuarial Loss	63,571	42,693	42,013	49,132
Plan Amendment Prior Service Credit	-	-	(101,384)	(42,357)
Curtailment	-	-	-	605
Benefit Payments	(72,472)	(64,472)	(38,269)	(38,347)
Participant Contributions	-	-	8,545	8,828
Medicare Subsidy	-	-	2,556	2,452
Benefit Obligation as of December 31	$ 1,068,186	$ 1,020,890	$ 466,290	$ 519,892
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1	$ 925,939	$ 799,281	$ 311,836	$ 333,198
Actual Gain (Loss) on Plan Assets	118,395	63,181	65,125	(6,589)
Company Contributions	43,253	127,949	19,064	14,746
Participant Contributions	-	-	8,545	8,828
Benefit Payments	(72,472)	(64,472)	(38,269)	(38,347)
Fair Value of Plan Assets as of December 31	$ 1,015,115	$ 925,939	$ 366,301	$ 311,836
Underfunded Status as of December 31	$ (53,071)	$ (94,951)	$ (99,989)	$ (208,056)

PSO

	Pension Plans		Other Postretirement Benefit Plans	
	2012	2011	2012	2011
Change in Benefit Obligation	(in thousands)			
Benefit Obligation as of January 1	$ 277,448	$ 268,180	$ 125,164	$ 116,935
Service Cost	5,951	5,760	2,836	2,621
Interest Cost	12,301	13,285	5,797	6,046
Actuarial Loss	6,128	7,679	7,511	16,705
Plan Amendment Prior Service Credit	-	-	(35,971)	(11,612)
Benefit Payments	(22,143)	(17,456)	(8,363)	(8,110)
Participant Contributions	-	-	2,024	1,926
Medicare Subsidy	-	-	682	653
Benefit Obligation as of December 31	$ 279,685	$ 277,448	$ 99,680	$ 125,164
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1	$ 245,769	$ 213,576	$ 83,090	$ 83,917
Actual Gain on Plan Assets	28,861	16,430	8,089	646
Company Contributions	12,336	33,219	5,681	4,711
Participant Contributions	-	-	2,024	1,926
Benefit Payments	(22,143)	(17,456)	(8,363)	(8,110)
Fair Value of Plan Assets as of December 31	$ 264,823	$ 245,769	$ 90,521	$ 83,090
Underfunded Status as of December 31	$ (14,862)	$ (31,679)	$ (9,159)	$ (42,074)

SWEPCo	Pension Plans		Other Postretirement Benefit Plans	
	2012	2011	2012	2011
Change in Benefit Obligation	(in thousands)			
Benefit Obligation as of January 1	$ 277,594	$ 267,206	$ 145,160	$ 129,726
Service Cost	7,099	6,573	3,324	3,029
Interest Cost	12,537	13,331	6,673	6,969
Actuarial Loss	9,752	7,861	7,885	24,547
Plan Amendment Prior Service Credit	-	-	(47,309)	(13,534)
Benefit Payments	(21,422)	(17,377)	(8,610)	(8,226)
Participant Contributions	-	-	2,189	2,041
Medicare Subsidy	-	-	636	608
Benefit Obligation as of December 31	$ 285,560	$ 277,594	$ 109,948	$ 145,160
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1	$ 255,861	$ 224,618	$ 96,364	$ 93,097
Actual Gain on Plan Assets	31,992	17,283	3,143	3,797
Company Contributions	13,268	31,337	6,760	5,655
Participant Contributions	-	-	2,189	2,041
Benefit Payments	(21,422)	(17,377)	(8,610)	(8,226)
Fair Value of Plan Assets as of December 31	$ 279,699	$ 255,861	$ 99,846	$ 96,364
Underfunded Status as of December 31	$ (5,861)	$ (21,733)	$ (10,102)	$ (48,796)

Amounts Recognized on the Registrant Subsidiaries' Balance Sheets as of December 31, 2012 and 2011

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
APCo	2012	2011	2012	2011
	(in thousands)			
Other Current Liabilities - Accrued Short-term Benefit Liability	$ (34)	$ (34)	$ (2,836)	$ (2,956)
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	(96,856)	(110,660)	(78,396)	(162,791)
Underfunded Status	$ (96,890)	$ (110,694)	$ (81,232)	$ (165,747)

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
I&M	2012	2011	2012	2011
	(in thousands)			
Other Current Liabilities - Accrued Short-term Benefit Liability	$ (15)	$ (14)	$ (290)	$ (308)
Deferred Credits and Other Noncurrent Liabilities - Accrued Long-term Benefit Liability	(66,932)	(77,737)	(24,135)	(95,808)
Underfunded Status	$ (66,947)	$ (77,751)	$ (24,425)	$ (96,116)

OPCo	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2012	2011	2012	2011
	(in thousands)			
Other Current Liabilities - Accrued Short-term Benefit Liability	$ (64)	$ (62)	$ (986)	$ (991)
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	(53,007)	(94,889)	(99,003)	(207,065)
Underfunded Status	$ (53,071)	$ (94,951)	$ (99,989)	$ (208,056)

PSO	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2012	2011	2012	2011
	(in thousands)			
Other Current Liabilities - Accrued Short-term Benefit Liability	$ (89)	$ (88)	$ -	$ -
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	(14,773)	(31,591)	(9,159)	(42,074)
Underfunded Status	$ (14,862)	$ (31,679)	$ (9,159)	$ (42,074)

SWEPCo	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2012	2011	2012	2011
	(in thousands)			
Other Current Liabilities - Accrued Short-term Benefit Liability	$ (80)	$ (78)	$ -	$ -
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	(5,781)	(21,655)	(10,102)	(48,796)
Underfunded Status	$ (5,861)	$ (21,733)	$ (10,102)	$ (48,796)

Amounts Included in AOCI and Regulatory Assets as of December 31, 2012 and 2011

APCo	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2012	2011	2012	2011
Components	(in thousands)			
Net Actuarial Loss	$ 303,483	$ 308,223	$ 167,173	$ 174,615
Prior Service Cost (Credit)	918	1,393	(110,726)	(33,060)
Transition Obligation	-	-	-	780
Recorded as				
Regulatory Assets	$ 299,456	$ 305,558	$ 13,189	$ 56,764
Deferred Income Taxes	1,732	1,420	15,140	29,951
Net of Tax AOCI	3,213	2,638	28,118	55,620

I&M

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2012	2011	2012	2011
Components	(in thousands)			
Net Actuarial Loss	$ 211,443	$ 216,107	$ 125,935	$ 121,238
Prior Service Cost (Credit)	900	1,307	(103,959)	(27,491)
Transition Obligation	-	-	-	132
Recorded as				
Regulatory Assets	$ 202,821	$ 207,237	$ 17,976	$ 84,155
Deferred Income Taxes	3,332	3,561	1,400	3,403
Net of Tax AOCI	6,190	6,616	2,600	6,321

OPCo

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2012	2011	2012	2011
Components	(in thousands)			
Net Actuarial Loss	$ 500,318	$ 517,180	$ 216,350	$ 231,189
Prior Service Cost (Credit)	1,282	2,025	(142,253)	(44,742)
Transition Obligation	-	-	-	104
Recorded as				
Regulatory Assets	$ 289,931	$ 305,240	$ 19,754	$ 84,472
Deferred Income Taxes	74,084	74,888	19,020	35,728
Net of Tax AOCI	137,585	139,077	35,323	66,351

PSO

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2012	2011	2012	2011
Components	(in thousands)			
Net Actuarial Loss	$ 123,132	$ 136,056	$ 56,493	$ 54,516
Prior Service Cost (Credit)	1,129	181	(47,350)	(12,458)
Recorded as				
Regulatory Assets	$ 124,261	$ 136,237	$ 9,143	$ 42,058

SWEPCo

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2012	2011	2012	2011
Components	(in thousands)			
Net Actuarial Loss	$ 121,839	$ 133,542	$ 67,223	$ 59,541
Prior Service Cost (Credit)	1,353	560	(57,138)	(10,762)
Recorded as				
Regulatory Assets	$ 123,192	$ 134,102	$ 6,528	$ 31,407
Deferred Income Taxes	-	-	1,246	6,081
Net of Tax AOCI	-	-	2,311	11,291

Components of the change in amounts included in AOCI and Regulatory Assets by Registrant Subsidiary during the years ended December 31, 2012 and 2011 are as follows:

Pension Plans - Components	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
			(in thousands)		
Actuarial Loss (Gain) During the Year	$ 15,599	$ 12,905	$ 13,577	$ (4,718)	$ (3,373)
Amortization of Actuarial Loss	(20,339)	(17,569)	(30,439)	(8,206)	(8,330)
Amortization of Prior Service Credit (Cost)	(475)	(407)	(743)	948	793
Change for the Year Ended December 31, 2012	$ (5,215)	$ (5,071)	$ (17,605)	$ (11,976)	$ (10,910)

Pension Plans - Components	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
			(in thousands)		
Actuarial Loss During the Year	$ 33,995	$ 21,372	$ 44,976	$ 8,712	$ 8,958
Amortization of Actuarial Loss	(16,570)	(14,144)	(24,828)	(6,757)	(6,759)
Amortization of Prior Service Credit (Cost)	(917)	(744)	(1,474)	950	795
Change for the Year Ended December 31, 2011	$ 16,508	$ 6,484	$ 18,674	$ 2,905	$ 2,994

Other Postretirement Benefit Plans - Components	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
			(in thousands)		
Actuarial Loss (Gain) During the Year	$ 3,084	$ 11,747	$ (1,170)	$ 5,166	$ 11,341
Amortization of Actuarial Loss	(10,526)	(7,050)	(13,669)	(3,189)	(3,659)
Prior Service Credit	(80,528)	(78,851)	(101,384)	(35,971)	(47,309)
Amortization of Prior Service Credit	2,862	2,383	3,873	1,079	933
Amortization of Transition Obligation	(780)	(132)	(104)	-	-
Change for the Year Ended December 31, 2012	$ (85,888)	$ (71,903)	$ (112,454)	$ (32,915)	$ (38,694)

Other Postretirement Benefit Plans - Components	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
			(in thousands)		
Actuarial Loss During the Year	$ 65,104	$ 46,321	$ 79,611	$ 22,147	$ 23,619
Amortization of Actuarial Loss	(5,839)	(3,566)	(7,298)	(1,553)	(1,785)
Prior Service Credit	(31,145)	(24,846)	(42,357)	(11,612)	(9,409)
Amortization of Prior Service Credit (Cost)	171	237	212	75	(258)
Amortization of Transition Obligation	(1,167)	(188)	(150)	-	-
Change for the Year Ended December 31, 2011	$ 27,124	$ 17,958	$ 30,018	$ 9,057	$ 12,167

Pension and Other Postretirement Plans' Assets

The following tables present the classification of pension plan assets within the fair value hierarchy by Registrant Subsidiary as of December 31, 2012:

APCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 173,149	$ -	$ -	$ -	$ 173,149	27.9 %
International	65,757	-	-	-	65,757	10.5 %
Real Estate Investment Trusts	11,986	-	-	-	11,986	1.9 %
Common Collective Trust - International	-	574	-	-	574	0.1 %
Subtotal - Equities	250,892	574	-	-	251,466	40.4 %
Fixed Income:						
Common Collective Trust - Debt	-	4,200	-	-	4,200	0.7 %
United States Government and Agency Securities	-	94,682	-	-	94,682	15.2 %
Corporate Debt	-	163,484	-	-	163,484	26.3 %
Foreign Debt	-	26,292	-	-	26,292	4.2 %
State and Local Government	-	5,821	-	-	5,821	0.9 %
Other - Asset Backed	-	4,714	-	-	4,714	0.8 %
Subtotal - Fixed Income	-	299,193	-	-	299,193	48.1 %
Real Estate	-	-	29,063	-	29,063	4.7 %
Alternative Investments	-	-	25,888	-	25,888	4.2 %
Securities Lending	-	10,633	-	-	10,633	1.7 %
Securities Lending Collateral (a)	-	-	-	(12,025)	(12,025)	(1.9)%
Cash and Cash Equivalents	-	16,646	-	-	16,646	2.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	706	706	0.1 %
Total	$ 250,892	$ 327,046	$ 54,951	$ (11,319)	$ 621,570	100.0 %

I&M

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 153,776	$ -	$ -	$ -	$ 153,776	27.9 %
International	58,400	-	-	-	58,400	10.5 %
Real Estate Investment Trusts	10,645	-	-	-	10,645	1.9 %
Common Collective Trust - International	-	510	-	-	510	0.1 %
Subtotal - Equities	222,821	510	-	-	223,331	40.4 %
Fixed Income:						
Common Collective Trust - Debt	-	3,730	-	-	3,730	0.7 %
United States Government and Agency Securities	-	84,089	-	-	84,089	15.2 %
Corporate Debt	-	145,193	-	-	145,193	26.3 %
Foreign Debt	-	23,350	-	-	23,350	4.2 %
State and Local Government	-	5,170	-	-	5,170	0.9 %
Other - Asset Backed	-	4,187	-	-	4,187	0.8 %
Subtotal - Fixed Income	-	265,719	-	-	265,719	48.1 %
Real Estate	-	-	25,811	-	25,811	4.7 %
Alternative Investments	-	-	22,992	-	22,992	4.2 %
Securities Lending	-	9,443	-	-	9,443	1.7 %
Securities Lending Collateral (a)	-	-	-	(10,680)	(10,680)	(1.9)%
Cash and Cash Equivalents	-	14,783	-	-	14,783	2.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	627	627	0.1 %
Total	$ 222,821	$ 290,455	$ 48,803	$ (10,053)	$ 552,026	100.0 %

OPCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 282,777	$ -	$ -	$ -	$ 282,777	27.9 %
International	107,391	-	-	-	107,391	10.5 %
Real Estate Investment Trusts	19,576	-	-	-	19,576	1.9 %
Common Collective Trust - International	-	938	-	-	938	0.1 %
Subtotal - Equities	409,744	938	-	-	410,682	40.4 %
Fixed Income:						
Common Collective Trust - Debt	-	6,858	-	-	6,858	0.7 %
United States Government and Agency Securities	-	154,630	-	-	154,630	15.2 %
Corporate Debt	-	266,994	-	-	266,994	26.3 %
Foreign Debt	-	42,938	-	-	42,938	4.2 %
State and Local Government	-	9,506	-	-	9,506	0.9 %
Other - Asset Backed	-	7,699	-	-	7,699	0.8 %
Subtotal - Fixed Income	-	488,625	-	-	488,625	48.1 %
Real Estate	-	-	47,464	-	47,464	4.7 %
Alternative Investments	-	-	42,279	-	42,279	4.2 %
Securities Lending	-	17,365	-	-	17,365	1.7 %
Securities Lending Collateral (a)	-	-	-	(19,639)	(19,639)	(1.9)%
Cash and Cash Equivalents	-	27,185	-	-	27,185	2.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	1,154	1,154	0.1 %
Total	$ 409,744	$ 534,113	$ 89,743	$ (18,485)	$ 1,015,115	100.0 %

PSO

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 73,770	$ -	$ -	$ -	$ 73,770	27.9 %
International	28,016	-	-	-	28,016	10.5 %
Real Estate Investment Trusts	5,107	-	-	-	5,107	1.9 %
Common Collective Trust - International	-	245	-	-	245	0.1 %
Subtotal - Equities	106,893	245	-	-	107,138	40.4 %
Fixed Income:						
Common Collective Trust - Debt	-	1,789	-	-	1,789	0.7 %
United States Government and Agency Securities	-	40,340	-	-	40,340	15.2 %
Corporate Debt	-	69,653	-	-	69,653	26.3 %
Foreign Debt	-	11,202	-	-	11,202	4.2 %
State and Local Government	-	2,480	-	-	2,480	0.9 %
Other - Asset Backed	-	2,009	-	-	2,009	0.8 %
Subtotal - Fixed Income	-	127,473	-	-	127,473	48.1 %
Real Estate	-	-	12,382	-	12,382	4.7 %
Alternative Investments	-	-	11,030	-	11,030	4.2 %
Securities Lending	-	4,530	-	-	4,530	1.7 %
Securities Lending Collateral (a)	-	-	-	(5,123)	(5,123)	(1.9)%
Cash and Cash Equivalents	-	7,092	-	-	7,092	2.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	301	301	0.1 %
Total	$ 106,893	$ 139,340	$ 23,412	$ (4,822)	$ 264,823	100.0 %

SWEPCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 77,915	$ -	$ -	$ -	$ 77,915	27.9 %
International	29,590	-	-	-	29,590	10.5 %
Real Estate Investment Trusts	5,394	-	-	-	5,394	1.9 %
Common Collective Trust - International	-	258	-	-	258	0.1 %
Subtotal - Equities	112,899	258	-	-	113,157	40.4 %
Fixed Income:						
Common Collective Trust - Debt	-	1,890	-	-	1,890	0.7 %
United States Government and Agency Securities	-	42,606	-	-	42,606	15.2 %
Corporate Debt	-	73,566	-	-	73,566	26.3 %
Foreign Debt	-	11,831	-	-	11,831	4.2 %
State and Local Government	-	2,619	-	-	2,619	0.9 %
Other - Asset Backed	-	2,121	-	-	2,121	0.8 %
Subtotal - Fixed Income	-	134,633	-	-	134,633	48.1 %
Real Estate	-	-	13,078	-	13,078	4.7 %
Alternative Investments	-	-	11,649	-	11,649	4.2 %
Securities Lending	-	4,785	-	-	4,785	1.7 %
Securities Lending Collateral (a)	-	-	-	(5,411)	(5,411)	(1.9)%
Cash and Cash Equivalents	-	7,490	-	-	7,490	2.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	318	318	0.1 %
Total	$ 112,899	$ 147,166	$ 24,727	$ (5,093)	$ 279,699	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 tables set forth a reconciliation of changes in the fair value of assets classified as Level 3 in the fair value hierarchy by Registrant Subsidiary for pension assets:

APCo	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2012	$ 846	$ 21,666	$ 21,269	$ 43,781
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	3,913	1,319	5,232
Relating to Assets Sold During the Period	(298)	-	640	342
Purchases and Sales	(548)	3,484	2,660	5,596
Transfers into Level 3	-	-	-	-
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2012	$ -	$ 29,063	$ 25,888	$ 54,951

I&M	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2012	$ 747	$ 19,129	$ 18,779	$ 38,655
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	3,535	1,203	4,738
Relating to Assets Sold During the Period	(263)	-	584	321
Purchases and Sales	(484)	3,147	2,426	5,089
Transfers into Level 3	-	-	-	-
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2012	$ -	$ 25,811	$ 22,992	$ 48,803

OPCo	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2012	$ 1,372	$ 35,148	$ 34,505	$ 71,025
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	6,515	2,220	8,735
Relating to Assets Sold During the Period	(483)	-	1,077	594
Purchases and Sales	(889)	5,801	4,477	9,389
Transfers into Level 3	-	-	-	-
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2012	$ -	$ 47,464	$ 42,279	$ 89,743

PSO	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2012	$ 364	$ 9,329	$ 9,159	$ 18,852
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	1,615	534	2,149
Relating to Assets Sold During the Period	(128)	-	259	131
Purchases and Sales	(236)	1,438	1,078	2,280
Transfers into Level 3	-	-	-	-
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2012	$ -	$ 12,382	$ 11,030	$ 23,412

SWEPCo	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2012	$ 379	$ 9,712	$ 9,535	$ 19,626
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	1,780	603	2,383
Relating to Assets Sold During the Period	(134)	-	293	159
Purchases and Sales	(245)	1,586	1,218	2,559
Transfers into Level 3	-	-	-	-
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2012	$ -	$ 13,078	$ 11,649	$ 24,727

The following tables present the classification of OPEB plan assets within the fair value hierarchy by Registrant Subsidiary as of December 31, 2012:

APCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 72,063	$ -	$ -	$ -	$ 72,063	26.9 %
International	86,158	-	-	-	86,158	32.2 %
Subtotal - Equities	158,221	-	-	-	158,221	59.1 %
Fixed Income:						
Common Collective Trust - Debt	-	12,388	-	-	12,388	4.6 %
United States Government and Agency Securities	-	14,036	-	-	14,036	5.2 %
Corporate Debt	-	26,437	-	-	26,437	9.9 %
Foreign Debt	-	4,469	-	-	4,469	1.7 %
State and Local Government	-	1,242	-	-	1,242	0.5 %
Other - Asset Backed	-	1,678	-	-	1,678	0.6 %
Subtotal - Fixed Income	-	60,250	-	-	60,250	22.5 %
Trust Owned Life Insurance:						
International Equities	-	8,800	-	-	8,800	3.3 %
United States Bonds	-	27,762	-	-	27,762	10.3 %
Cash and Cash Equivalents	10,598	1,947	-	-	12,545	4.7 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	180	180	0.1 %
Total	$ 168,819	$ 98,759	$ -	$ 180	$ 267,758	100.0 %

I&M

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

OPCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 98,583	$ -	$ -	$ -	$ 98,583	26.9 %
International	117,867	-	-	-	117,867	32.2 %
Subtotal - Equities	216,450	-	-	-	216,450	59.1 %
Fixed Income:						
Common Collective Trust - Debt	-	16,947	-	-	16,947	4.6 %
United States Government and Agency Securities	-	19,202	-	-	19,202	5.2 %
Corporate Debt	-	36,166	-	-	36,166	9.9 %
Foreign Debt	-	6,113	-	-	6,113	1.7 %
State and Local Government	-	1,700	-	-	1,700	0.5 %
Other - Asset Backed	-	2,296	-	-	2,296	0.6 %
Subtotal - Fixed Income	-	82,424	-	-	82,424	22.5 %
Trust Owned Life Insurance:						
International Equities	-	12,038	-	-	12,038	3.3 %
United States Bonds	-	37,980	-	-	37,980	10.3 %
Cash and Cash Equivalents	14,499	2,664	-	-	17,163	4.7 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	246	246	0.1 %
Total	$ 230,949	$ 135,106	$ -	$ 246	$ 366,301	100.0 %

PSO

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 24,362	$ -	$ -	$ -	$ 24,362	26.9 %
International	29,128	-	-	-	29,128	32.2 %
Subtotal - Equities	53,490	-	-	-	53,490	59.1 %
Fixed Income:						
Common Collective Trust - Debt	-	4,188	-	-	4,188	4.6 %
United States Government and Agency Securities	-	4,745	-	-	4,745	5.2 %
Corporate Debt	-	8,937	-	-	8,937	9.9 %
Foreign Debt	-	1,511	-	-	1,511	1.7 %
State and Local Government	-	420	-	-	420	0.5 %
Other - Asset Backed	-	567	-	-	567	0.6 %
Subtotal - Fixed Income	-	20,368	-	-	20,368	22.5 %
Trust Owned Life Insurance:						
International Equities	-	2,975	-	-	2,975	3.3 %
United States Bonds	-	9,386	-	-	9,386	10.3 %
Cash and Cash Equivalents	3,583	658	-	-	4,241	4.7 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	61	61	0.1 %
Total	$ 57,073	$ 33,387	$ -	$ 61	$ 90,521	100.0 %

SWEPCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 26,874	$ -	$ -	$ -	$ 26,874	26.9 %
International	32,128	-	-	-	32,128	32.2 %
Subtotal - Equities	59,002	-	-	-	59,002	59.1 %
Fixed Income:						
Common Collective Trust - Debt	-	4,619	-	-	4,619	4.6 %
United States Government and Agency Securities	-	5,234	-	-	5,234	5.2 %
Corporate Debt	-	9,858	-	-	9,858	9.9 %
Foreign Debt	-	1,666	-	-	1,666	1.7 %
State and Local Government	-	463	-	-	463	0.5 %
Other - Asset Backed	-	626	-	-	626	0.6 %
Subtotal - Fixed Income	-	22,466	-	-	22,466	22.5 %
Trust Owned Life Insurance:						
International Equities	-	3,281	-	-	3,281	3.3 %
United States Bonds	-	10,352	-	-	10,352	10.3 %
Cash and Cash Equivalents	3,952	726	-	-	4,678	4.7 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	67	67	0.1 %
Total	$ 62,954	$ 36,825	$ -	$ 67	$ 99,846	100.0 %

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

The following tables present the classification of pension plan assets within the fair value hierarchy by Registrant Subsidiary as of December 31, 2011:

APCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 192,957	$ -	$ -	$ -	$ 192,957	33.8 %
International	52,904	-	-	-	52,904	9.3 %
Real Estate Investment Trusts	13,794	-	-	-	13,794	2.4 %
Common Collective Trust - International	-	17,038	-	-	17,038	3.0 %
Subtotal - Equities	259,655	17,038	-	-	276,693	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	3,483	-	-	3,483	0.6 %
United States Government and Agency Securities	-	75,042	-	-	75,042	13.2 %
Corporate Debt	-	130,606	846	-	131,452	23.0 %
Foreign Debt	-	25,289	-	-	25,289	4.4 %
State and Local Government	-	6,374	-	-	6,374	1.1 %
Other - Asset Backed	-	3,449	-	-	3,449	0.6 %
Subtotal - Fixed Income	-	244,243	846	-	245,089	42.9 %
Real Estate	-	-	21,666	-	21,666	3.8 %
Alternative Investments	-	-	21,269	-	21,269	3.7 %
Securities Lending	-	28,488	-	-	28,488	5.0 %
Securities Lending Collateral (a)	-	-	-	(31,276)	(31,276)	(5.5)%
Cash and Cash Equivalents	-	12,306	-	-	12,306	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(3,479)	(3,479)	(0.6)%
Total	$ 259,655	$ 302,075	$ 43,781	$ (34,755)	$ 570,756	100.0 %

I&M

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 170,364	$ -	$ -	$ -	$ 170,364	33.8 %
International	46,709	-	-	-	46,709	9.3 %
Real Estate Investment Trusts	12,179	-	-	-	12,179	2.4 %
Common Collective Trust - International	-	15,043	-	-	15,043	3.0 %
Subtotal - Equities	229,252	15,043	-	-	244,295	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	3,075	-	-	3,075	0.6 %
United States Government and Agency Securities	-	66,255	-	-	66,255	13.2 %
Corporate Debt	-	115,313	747	-	116,060	23.0 %
Foreign Debt	-	22,328	-	-	22,328	4.4 %
State and Local Government	-	5,628	-	-	5,628	1.1 %
Other - Asset Backed	-	3,045	-	-	3,045	0.6 %
Subtotal - Fixed Income	-	215,644	747	-	216,391	42.9 %
Real Estate	-	-	19,129	-	19,129	3.8 %
Alternative Investments	-	-	18,779	-	18,779	3.7 %
Securities Lending	-	25,153	-	-	25,153	5.0 %
Securities Lending Collateral (a)	-	-	-	(27,614)	(27,614)	(5.5)%
Cash and Cash Equivalents	-	10,865	-	-	10,865	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(3,072)	(3,072)	(0.6)%
Total	$ 229,252	$ 266,705	$ 38,655	$ (30,686)	$ 503,926	100.0 %

OPCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 313,034	$ -	$ -	$ -	$ 313,034	33.8 %
International	85,825	-	-	-	85,825	9.3 %
Real Estate Investment Trusts	22,379	-	-	-	22,379	2.4 %
Common Collective Trust - International	-	27,641	-	-	27,641	3.0 %
Subtotal - Equities	421,238	27,641	-	-	448,879	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	5,650	-	-	5,650	0.6 %
United States Government and Agency Securities	-	121,741	-	-	121,741	13.2 %
Corporate Debt	-	211,883	1,372	-	213,255	23.0 %
Foreign Debt	-	41,027	-	-	41,027	4.4 %
State and Local Government	-	10,341	-	-	10,341	1.1 %
Other - Asset Backed	-	5,595	-	-	5,595	0.6 %
Subtotal - Fixed Income	-	396,237	1,372	-	397,609	42.9 %
Real Estate	-	-	35,148	-	35,148	3.8 %
Alternative Investments	-	-	34,505	-	34,505	3.7 %
Securities Lending	-	46,217	-	-	46,217	5.0 %
Securities Lending Collateral (a)	-	-	-	(50,739)	(50,739)	(5.5)%
Cash and Cash Equivalents	-	19,964	-	-	19,964	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(5,644)	(5,644)	(0.6)%
Total	$ 421,238	$ 490,059	$ 71,025	$ (56,383)	$ 925,939	100.0 %

PSO

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 83,086	$ -	$ -	$ -	$ 83,086	33.8 %
International	22,781	-	-	-	22,781	9.3 %
Real Estate Investment Trusts	5,940	-	-	-	5,940	2.4 %
Common Collective Trust - International	-	7,337	-	-	7,337	3.0 %
Subtotal - Equities	111,807	7,337	-	-	119,144	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	1,500	-	-	1,500	0.6 %
United States Government and Agency Securities	-	32,313	-	-	32,313	13.2 %
Corporate Debt	-	56,239	364	-	56,603	23.0 %
Foreign Debt	-	10,890	-	-	10,890	4.4 %
State and Local Government	-	2,745	-	-	2,745	1.1 %
Other - Asset Backed	-	1,485	-	-	1,485	0.6 %
Subtotal - Fixed Income	-	105,172	364	-	105,536	42.9 %
Real Estate	-	-	9,329	-	9,329	3.8 %
Alternative Investments	-	-	9,159	-	9,159	3.7 %
Securities Lending	-	12,267	-	-	12,267	5.0 %
Securities Lending Collateral (a)	-	-	-	(13,467)	(13,467)	(5.5)%
Cash and Cash Equivalents	-	5,299	-	-	5,299	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(1,498)	(1,498)	(0.6)%
Total	$ 111,807	$ 130,075	$ 18,852	$ (14,965)	$ 245,769	100.0 %

SWEPCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 86,499	$ -	$ -	$ -	$ 86,499	33.8 %
International	23,716	-	-	-	23,716	9.3 %
Real Estate Investment Trusts	6,184	-	-	-	6,184	2.4 %
Common Collective Trust - International	-	7,638	-	-	7,638	3.0 %
Subtotal - Equities	116,399	7,638	-	-	124,037	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	1,561	-	-	1,561	0.6 %
United States Government and Agency Securities	-	33,640	-	-	33,640	13.2 %
Corporate Debt	-	58,549	379	-	58,928	23.0 %
Foreign Debt	-	11,337	-	-	11,337	4.4 %
State and Local Government	-	2,857	-	-	2,857	1.1 %
Other - Asset Backed	-	1,546	-	-	1,546	0.6 %
Subtotal - Fixed Income	-	109,490	379	-	109,869	42.9 %
Real Estate	-	-	9,712	-	9,712	3.8 %
Alternative Investments	-	-	9,535	-	9,535	3.7 %
Securities Lending	-	12,771	-	-	12,771	5.0 %
Securities Lending Collateral (a)	-	-	-	(14,020)	(14,020)	(5.5)%
Cash and Cash Equivalents	-	5,517	-	-	5,517	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(1,560)	(1,560)	(0.6)%
Total	$ 116,399	$ 135,416	$ 19,626	$ (15,580)	$ 255,861	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 tables set forth a reconciliation of changes in the fair value of assets classified as Level 3 in the fair value hierarchy for pension assets by Registrant Subsidiary:

APCo	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
			(in thousands)	
Balance as of January 1, 2011	$ -	$ 11,060	$ 17,281	$ 28,341
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	2,952	1,142	4,094
Relating to Assets Sold During the Period	-	-	392	392
Purchases and Sales	-	7,654	2,454	10,108
Transfers into Level 3	846	-	-	846
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2011	$ 846	$ 21,666	$ 21,269	$ 43,781

I&M	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
			(in thousands)	
Balance as of January 1, 2011	$ -	$ 9,742	$ 15,220	$ 24,962
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	2,612	1,019	3,631
Relating to Assets Sold During the Period	-	-	350	350
Purchases and Sales	-	6,775	2,190	8,965
Transfers into Level 3	747	-	-	747
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2011	$ 747	$ 19,129	$ 18,779	$ 38,655

OPCo	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
			(in thousands)	
Balance as of January 1, 2011	$ -	$ 17,239	$ 26,933	$ 44,172
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	4,985	2,167	7,152
Relating to Assets Sold During the Period	-	-	744	744
Purchases and Sales	-	12,924	4,661	17,585
Transfers into Level 3	1,372	-	-	1,372
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2011	$ 1,372	$ 35,148	$ 34,505	$ 71,025

PSO	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
			(in thousands)	
Balance as of January 1, 2011	$ -	$ 4,606	$ 7,197	$ 11,803
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	1,314	561	1,875
Relating to Assets Sold During the Period	-	-	193	193
Purchases and Sales	-	3,409	1,208	4,617
Transfers into Level 3	364	-	-	364
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2011	$ 364	$ 9,329	$ 9,159	$ 18,852

SWEPCo	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2011	$ -	$ 4,844	$ 7,569	$ 12,413
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	1,355	563	1,918
Relating to Assets Sold During the Period	-	-	194	194
Purchases and Sales	-	3,513	1,209	4,722
Transfers into Level 3	379	-	-	379
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2011	$ 379	$ 9,712	$ 9,535	$ 19,626

The following tables present the classification of OPEB plan assets within the fair value hierarchy by Registrant Subsidiary as of December 31, 2011:

APCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 56,670	$ -	$ -	$ -	$ 56,670	24.7 %
International	61,982	-	-	-	61,982	27.0 %
Common Collective Trust - Global	-	16,159	-	-	16,159	7.0 %
Subtotal - Equities	118,652	16,159	-	-	134,811	58.7 %
Fixed Income:						
Common Collective Trust - Debt	-	11,279	-	-	11,279	4.9 %
United States Government and Agency Securities	-	13,165	-	-	13,165	5.7 %
Corporate Debt	-	24,792	-	-	24,792	10.8 %
Foreign Debt	-	5,256	-	-	5,256	2.3 %
State and Local Government	-	1,371	-	-	1,371	0.6 %
Other - Asset Backed	-	312	-	-	312	0.1 %
Subtotal - Fixed Income	-	56,175	-	-	56,175	24.4 %
Trust Owned Life Insurance:						
International Equities	-	7,533	-	-	7,533	3.3 %
United States Bonds	-	25,719	-	-	25,719	11.2 %
Cash and Cash Equivalents	2,739	3,816	-	-	6,555	2.9 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	(1,058)	(1,058)	(0.5)%
Total	$ 121,391	$ 109,402	$ -	$ (1,058)	$ 229,735	100.0 %

I&M

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 %

OPCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 76,921	$ -	$ -	$ -	$ 76,921	24.7 %
International	84,133	-	-	-	84,133	27.0 %
Common Collective Trust - Global	-	21,934	-	-	21,934	7.0 %
Subtotal - Equities	161,054	21,934	-	-	182,988	58.7 %
Fixed Income:						
Common Collective Trust - Debt	-	15,310	-	-	15,310	4.9 %
United States Government and Agency Securities	-	17,870	-	-	17,870	5.7 %
Corporate Debt	-	33,652	-	-	33,652	10.8 %
Foreign Debt	-	7,134	-	-	7,134	2.3 %
State and Local Government	-	1,861	-	-	1,861	0.6 %
Other - Asset Backed	-	424	-	-	424	0.1 %
Subtotal - Fixed Income	-	76,251	-	-	76,251	24.4 %
Trust Owned Life Insurance:						
International Equities	-	10,225	-	-	10,225	3.3 %
United States Bonds	-	34,910	-	-	34,910	11.2 %
Cash and Cash Equivalents	3,718	5,180	-	-	8,898	2.9 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	(1,436)	(1,436)	(0.5)%
Total	$ 164,772	$ 148,500	$ -	$ (1,436)	$ 311,836	100.0 %

PSO

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 20,497	$ -	$ -	$ -	$ 20,497	24.7 %
International	22,417	-	-	-	22,417	27.0 %
Common Collective Trust - Global	-	5,844	-	-	5,844	7.0 %
Subtotal - Equities	42,914	5,844	-	-	48,758	58.7 %
Fixed Income:						
Common Collective Trust - Debt	-	4,079	-	-	4,079	4.9 %
United States Government and Agency Securities	-	4,762	-	-	4,762	5.7 %
Corporate Debt	-	8,967	-	-	8,967	10.8 %
Foreign Debt	-	1,901	-	-	1,901	2.3 %
State and Local Government	-	496	-	-	496	0.6 %
Other - Asset Backed	-	113	-	-	113	0.1 %
Subtotal - Fixed Income	-	20,318	-	-	20,318	24.4 %
Trust Owned Life Insurance:						
International Equities	-	2,724	-	-	2,724	3.3 %
United States Bonds	-	9,302	-	-	9,302	11.2 %
Cash and Cash Equivalents	991	1,380	-	-	2,371	2.9 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	(383)	(383)	(0.5)%
Total	$ 43,905	$ 39,568	$ -	$ (383)	$ 83,090	100.0 %

SWEPCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 23,770	$ -	$ -	$ -	$ 23,770	24.7 %
International	25,999	-	-	-	25,999	27.0 %
Common Collective Trust - Global	-	6,778	-	-	6,778	7.0 %
Subtotal - Equities	49,769	6,778	-	-	56,547	58.7 %
Fixed Income:						
Common Collective Trust - Debt	-	4,731	-	-	4,731	4.9 %
United States Government and Agency Securities	-	5,522	-	-	5,522	5.7 %
Corporate Debt	-	10,399	-	-	10,399	10.8 %
Foreign Debt	-	2,205	-	-	2,205	2.3 %
State and Local Government	-	575	-	-	575	0.6 %
Other - Asset Backed	-	131	-	-	131	0.1 %
Subtotal - Fixed Income	-	23,563	-	-	23,563	24.4 %
Trust Owned Life Insurance:						
International Equities	-	3,160	-	-	3,160	3.3 %
United States Bonds	-	10,788	-	-	10,788	11.2 %
Cash and Cash Equivalents	1,149	1,601	-	-	2,750	2.9 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	(444)	(444)	(0.5)%
Total	$ 50,918	$ 45,890	$ -	$ (444)	$ 96,364	100.0 %

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

Determination of Pension Expense

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

Accumulated Benefit Obligation	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Qualified Pension Plan	$ 708,476	$ 603,448	$ 1,048,796	$ 269,738	$ 273,860
Nonqualified Pension Plans	191	200	796	1,287	1,098
Total as of December 31, 2012	$ 708,667	$ 603,648	$ 1,049,592	$ 271,025	$ 274,958

Accumulated Benefit Obligation	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Qualified Pension Plan	$ 672,967	$ 569,855	$ 1,005,608	$ 269,230	$ 269,809
Nonqualified Pension Plans	234	168	821	1,368	1,223
Total as of December 31, 2011	$ 673,201	$ 570,023	$ 1,006,429	$ 270,598	$ 271,032

For the underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets of these plans as of December 31, 2012 and 2011 were as follows:

	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Projected Benefit Obligation	$ 718,460	$ 618,973	$ 1,068,186	$ 279,685	$ 1,098
Accumulated Benefit Obligation	$ 708,667	$ 603,648	$ 1,049,592	$ 271,025	$ 1,098
Fair Value of Plan Assets	621,570	552,026	1,015,115	264,823	-
Underfunded Accumulated Benefit Obligation as of December 31, 2012	$ (87,097)	$ (51,622)	$ (34,477)	$ (6,202)	$ (1,098)

	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Projected Benefit Obligation	$ 681,450	$ 581,677	$ 1,020,890	$ 277,448	$ 277,594
Accumulated Benefit Obligation	$ 673,201	$ 570,023	$ 1,006,429	$ 270,598	$ 271,032
Fair Value of Plan Assets	570,756	503,926	925,939	245,769	255,861
Underfunded Accumulated Benefit Obligation as of December 31, 2011	$ (102,445)	$ (66,097)	$ (80,490)	$ (24,829)	$ (15,171)

Estimated Future Benefit Payments and Contributions

The estimated pension benefit payments 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 also be made to maintain the funded status of the plan. For OPEB plans, expected payments include the payment of unfunded benefits. The following table provides the estimated contributions and payments by Registrant Subsidiary for 2013:

Company	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
APCo	$ 11,883	$ 3,079
I&M	14,867	315
OPCo	8,965	1,027
PSO	6,089	-
SWEPCo	11,345	-

The tables below reflect the total benefits expected to be paid from the plan or from the Registrant Subsidiary's assets. The payments include the participants' contributions to the plan for their share of the cost. In November 2012, changes to the retiree medical coverage were announced. Effective for retirements after December 2012, contributions to retiree medical coverage will be capped reducing exposure to future medical cost inflation. Effective for employees hired after December 2013, retiree medical coverage will not be provided. In December 2011, the prescription drug plan was amended for certain participants. The impact of the changes is reflected in the Benefit Plan Obligation tables as plan amendments. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for the pension benefits and OPEB are as follows:

Pension Plans	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
2013	$ 45,750	$ 36,365	$ 72,470	$ 20,560	$ 21,004
2014	47,455	36,958	73,771	21,772	22,223
2015	46,625	38,694	73,945	22,310	22,352
2016	47,604	39,469	75,347	22,297	22,278
2017	48,367	40,350	75,575	22,347	23,162
Years 2018 to 2022, in Total	245,312	213,444	370,934	110,866	114,257

Other Postretirement Benefit Plans: Benefit Payments	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
2013	$ 26,427	$ 17,092	$ 34,561	$ 7,821	$ 8,143
2014	27,549	17,999	35,532	8,169	8,748
2015	28,553	19,150	36,755	8,676	9,233
2016	29,738	20,468	38,435	9,239	9,879
2017	30,834	21,549	39,543	9,712	10,582
Years 2018 to 2022, in Total	172,977	127,047	224,357	56,882	64,145

Other Postretirement Benefit Plans: Medicare Subsidy Receipts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
2013	$ 243	$ 25	$ 41	$ -	$ -
2014	257	24	47	-	-
2015	269	23	58	-	-
2016	278	23	65	-	-
2017	283	22	76	-	-
Years 2018 to 2022, in Total	1,452	97	599	-	-

Components of Net Periodic Benefit Cost

The following tables provide the components of net periodic benefit cost by Registrant Subsidiary for the years ended December 31, 2012, 2011 and 2010:

APCo	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2012	2011	2010	2012	2011	2010
	(in thousands)					
Service Cost	$ 7,565	$ 7,199	$ 12,908	$ 5,387	$ 4,983	$ 5,722
Interest Cost	30,211	32,293	33,956	18,462	19,468	20,300
Expected Return on Plan Assets	(41,944)	(41,833)	(43,805)	(16,753)	(17,985)	(17,628)
Amortization of Transition Obligation	-	-	-	780	1,167	5,244
Amortization of Prior Service Cost (Credit)	475	917	917	(2,862)	(171)	-
Amortization of Net Actuarial Loss	20,339	16,570	11,842	10,526	5,839	5,410
Net Periodic Benefit Cost	16,646	15,146	15,818	15,540	13,301	19,048
Capitalized Portion	(6,525)	(5,604)	(6,058)	(6,092)	(4,921)	(7,295)
Net Periodic Benefit Cost Recognized as Expense	$ 10,121	$ 9,542	$ 9,760	$ 9,448	$ 8,380	$ 11,753

I&M	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2012	2011	2010	2012	2011	2010
	(in thousands)					
Service Cost	$ 9,908	$ 9,447	$ 15,284	$ 6,621	$ 6,119	$ 6,750
Interest Cost	26,245	27,726	29,085	12,785	13,610	14,164
Expected Return on Plan Assets	(37,566)	(36,856)	(35,040)	(12,847)	(13,886)	(13,397)
Amortization of Transition Obligation	-	-	-	132	188	2,814
Amortization of Prior Service Cost (Credit)	407	744	744	(2,383)	(237)	-
Amortization of Net Actuarial Loss	17,569	14,144	10,065	7,050	3,566	3,526
Net Periodic Benefit Cost	16,563	15,205	20,138	11,358	9,360	13,857
Capitalized Portion	(3,114)	(3,163)	(4,028)	(2,135)	(1,947)	(2,771)
Net Periodic Benefit Cost Recognized as Expense	$ 13,449	$ 12,042	$ 16,110	$ 9,223	$ 7,413	$ 11,086

OPCo	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2012	2011	2010	2012	2011	2010
	(in thousands)					
Service Cost	$ 11,003	$ 10,230	$ 17,254	$ 8,748	$ 7,827	$ 8,187
Interest Cost	45,194	48,350	51,900	24,189	25,497	26,498
Expected Return on Plan Assets	(68,401)	(65,464)	(69,077)	(22,555)	(24,514)	(24,092)
Curtailment	-	-	-	-	605	-
Amortization of Transition Obligation	-	-	-	104	150	6,642
Amortization of Prior Service Cost (Credit)	743	1,474	1,474	(3,873)	(212)	-
Amortization of Net Actuarial Loss	30,439	24,828	18,150	13,669	7,298	6,877
Net Periodic Benefit Cost	18,978	19,418	19,701	20,282	16,651	24,112
Capitalized Portion	(7,060)	(6,932)	(6,843)	(7,545)	(5,944)	(8,334)
Net Periodic Benefit Cost Recognized as Expense	$ 11,918	$ 12,486	$ 12,858	$ 12,737	$ 10,707	$ 15,778

PSO	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2012	2011	2010	2012	2011	2010
	(in thousands)					
Service Cost	$ 5,951	$ 5,760	$ 6,052	$ 2,836	$ 2,621	$ 2,815
Interest Cost	12,301	13,285	14,888	5,797	6,046	6,360
Expected Return on Plan Assets	(18,015)	(17,464)	(19,739)	(5,922)	(6,264)	(6,110)
Amortization of Transition Obligation	-	-	-	-	-	2,805
Amortization of Prior Service Credit	(948)	(950)	(950)	(1,079)	(75)	-
Amortization of Net Actuarial Loss	8,206	6,757	5,188	3,189	1,553	1,573
Net Periodic Benefit Cost	7,495	7,388	5,439	4,821	3,881	7,443
Capitalized Portion	(2,533)	(2,379)	(1,806)	(1,629)	(1,249)	(2,471)
Net Periodic Benefit Cost Recognized as Expense	$ 4,962	$ 5,009	$ 3,633	$ 3,192	$ 2,632	$ 4,972

SWEPCo	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2012	2011	2010	2012	2011	2010
	(in thousands)					
Service Cost	$ 7,099	$ 6,573	$ 7,046	$ 3,324	$ 3,029	$ 3,108
Interest Cost	12,537	13,331	15,093	6,673	6,969	6,940
Expected Return on Plan Assets	(18,866)	(18,380)	(19,489)	(6,795)	(7,200)	(6,646)
Amortization of Transition Obligation	-	-	-	-	-	2,461
Amortization of Prior Service Cost (Credit)	(793)	(795)	(796)	(933)	258	-
Amortization of Net Actuarial Loss	8,330	6,759	5,242	3,659	1,785	1,711
Net Periodic Benefit Cost	8,307	7,488	7,096	5,928	4,841	7,574
Capitalized Portion	(2,924)	(2,636)	(2,406)	(2,087)	(1,704)	(2,568)
Net Periodic Benefit Cost Recognized as Expense	$ 5,383	$ 4,852	$ 4,690	$ 3,841	$ 3,137	$ 5,006

Estimated amounts expected to be amortized to net periodic benefit costs (credits) and the impact on each Registrant Subsidiary's balance sheet during 2013 are shown in the following tables:

	APCo	I&M	OPCo	PSO	SWEPCo
Pension Plan - Components			(in thousands)		
Net Actuarial Loss	$ 24,305	$ 20,939	$ 36,137	$ 9,464	$ 9,662
Prior Service Cost	198	195	283	297	350
Total Estimated 2013 Amortization	$ 24,503	$ 21,134	$ 36,420	$ 9,761	$ 10,012
Pension Plans - Expected to be Recorded as					
Regulatory Asset	$ 24,367	$ 19,852	$ 19,387	$ 9,761	$ 10,012
Deferred Income Taxes	48	449	5,962	-	-
Net of Tax AOCI	88	833	11,071	-	-
Total	$ 24,503	$ 21,134	$ 36,420	$ 9,761	$ 10,012

	APCo	I&M	OPCo	PSO	SWEPCo
Other Postretirement Benefit Plans - Components			(in thousands)		
Net Actuarial Loss	$ 12,114	$ 7,624	$ 16,198	$ 3,480	$ 3,838
Prior Service Credit	(10,050)	(9,421)	(12,922)	(4,290)	(5,155)
Total Estimated 2013 Amortization	$ 2,064	$ (1,797)	$ 3,276	$ (810)	$ (1,317)
Other Postretirement Benefit Plans - Expected to be Recorded as					
Regulatory Asset	$ 99	$ (1,767)	$ 599	$ (810)	$ (899)
Deferred Income Taxes	688	(10)	937	-	(146)
Net of Tax AOCI	1,277	(20)	1,740	-	(272)
Total	$ 2,064	$ (1,797)	$ 3,276	$ (810)	$ (1,317)

American Electric Power System Retirement Savings Plans

The Registrant Subsidiaries participate 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 following table provides the cost for matching contributions to the retirement savings plans by Registrant Subsidiary for the years ended December 31, 2012, 2011 and 2010:

	Years Ended December 31,		
Company	**2012**	**2011**	**2010**
		(in thousands)	
APCo	$ 7,579	$ 7,432	$ 7,284
I&M	9,706	9,541	8,969
OPCo	10,798	10,166	9,706
PSO	3,732	3,626	3,505
SWEPCo	4,890	4,438	3,866

UMWA Benefits

APCo, I&M and OPCo provide 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. APCo, I&M and OPCo administer the health and welfare benefits and pay them from their 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, 2012 and 2011, without utilization of extended amortization provisions. The Plan adopted a funding improvement plan in May 2012, as required under the PPA. Contributions in 2012, 2011 and 2010 were made under a collective bargaining agreement that is scheduled to expire December 31, 2013, were immaterial and represent less than 5% of the total contributions in the plan's latest annual report for the years ended June 30, 2012, 2011 and 2010. The contributions did not include a surcharge. There are no minimum contributions for future years.

7. BUSINESS SEGMENTS

The Registrant Subsidiaries each have one reportable segment, an integrated electricity generation, transmission and distribution business. The Registrant Subsidiaries' other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

The Registrant Subsidiaries are exposed to certain market risks as major power producers and marketers 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 the Registrant Subsidiaries due to changes in the underlying market prices or rates. AEPSC, on behalf of the Registrant Subsidiaries, manages these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

AEPSC, on behalf of the Registrant Subsidiaries, 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 the Registrant Subsidiaries, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with the Registrant Subsidiaries' 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 the Registrant Subsidiaries, 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 tables represent the gross notional volume of the Registrant Subsidiaries' outstanding derivative contracts as of December 31, 2012 and 2011:

Notional Volume of Derivative Instruments
December 31, 2012

Primary Risk Exposure	Unit of Measure	APCo	I&M	OPCo	PSO	SWEPCo
				(in thousands)		
Commodity:						
Power	MWhs	94,059	64,791	132,188	-	-
Coal	Tons	1,401	2,711	3,033	1,980	1,312
Natural Gas	MMBtus	10,077	6,922	14,163	-	-
Heating Oil and Gasoline	Gallons	1,050	532	1,260	616	585
Interest Rate	USD	$ 24,146	$ 16,584	$ 33,934	$ -	$ -
Interest Rate and Foreign Currency	USD	$ -	$ 200,000	$ -	$ -	$ -

Notional Volume of Derivative Instruments
December 31, 2011

Primary Risk Exposure	Unit of Measure	APCo	I&M	OPCo	PSO	SWEPCo
				(in thousands)		
Commodity:						
Power	MWhs	169,459	109,326	229,468	39	49
Coal	Tons	3,714	1,920	8,337	3,574	2,974
Natural Gas	MMBtus	7,923	5,081	10,728	115	145
Heating Oil and Gasoline	Gallons	1,057	525	1,254	618	569
Interest Rate	USD	$ 31,029	$ 19,890	$ 42,093	$ 175	$ 203
Interest Rate and Foreign Currency	USD	$ -	$ 200,000	$ -	$ -	$ 200,069

Fair Value Hedging Strategies

AEPSC, on behalf of the Registrant Subsidiaries, 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 the Registrant Subsidiaries, 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. The Registrant Subsidiaries do not hedge all commodity price risk.

The Registrant Subsidiaries' vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of the Registrant Subsidiaries, 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." The Registrant Subsidiaries do not hedge all fuel price risk.

AEPSC, on behalf of the Registrant Subsidiaries, 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 the Registrant Subsidiaries, 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. The Registrant Subsidiaries do not hedge all interest rate exposure.

At times, the Registrant Subsidiaries are 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 the Registrant Subsidiaries, 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. The Registrant Subsidiaries do 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, the Registrant Subsidiaries also apply 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," the Registrant Subsidiaries reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrant Subsidiaries are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2012 and 2011 balance sheets, the Registrant Subsidiaries 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,			
	2012		2011	
Company	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)			
APCo	$ 1,262	$ 11,029	$ 4,291	$ 28,964
I&M	867	7,576	2,752	18,547
OPCo	1,774	15,500	5,810	39,183
PSO	-	-	53	130
SWEPCo	-	-	66	124

The following tables represent the gross fair value of the Registrant Subsidiaries' derivative activity on the balance sheets as of December 31, 2012 and 2011:

Fair Value of Derivative Instruments
December 31, 2012

APCo

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (d)
			(in thousands)			
Current Risk Management Assets	$ 127,645	$ 338	$ -	$ 127,983	$ (97,023)	$ 30,960
Long-term Risk Management Assets	60,498	215	-	60,713	(26,353)	34,360
Total Assets	188,143	553	-	188,696	(123,376)	65,320
Current Risk Management Liabilities	119,430	1,182	-	120,612	(103,914)	16,698
Long-term Risk Management Liabilities	47,281	424	-	47,705	(29,229)	18,476
Total Liabilities	166,711	1,606	-	168,317	(133,143)	35,174
Total MTM Derivative Contract Net Assets (Liabilities)	$ 21,432	$ (1,053)	$ -	$ 20,379	$ 9,767	$ 30,146

Fair Value of Derivative Instruments
December 31, 2011

APCo

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (c)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (d)
			(in thousands)			
Current Risk Management Assets	$ 232,784	$ 1,040	$ -	$ 233,824	$ (194,179)	$ 39,645
Long-term Risk Management Assets	99,751	90	-	99,841	(60,615)	39,226
Total Assets	332,535	1,130	-	333,665	(254,794)	78,871
Current Risk Management Liabilities	235,354	2,767	-	238,121	(211,515)	26,606
Long-term Risk Management Liabilities	82,058	350	-	82,408	(69,485)	12,923
Total Liabilities	317,412	3,117	-	320,529	(281,000)	39,529
Total MTM Derivative Contract Net Assets (Liabilities)	$ 15,123	$ (1,987)	$ -	$ 13,136	$ 26,206	$ 39,342

Fair Value of Derivative Instruments
December 31, 2012

I&M

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (d)
			(in thousands)			
Current Risk Management Assets	$ 93,268	$ 220	$ -	$ 93,488	$ (66,514)	$ 26,974
Long-term Risk Management Assets	41,553	148	-	41,701	(18,132)	23,569
Total Assets	134,821	368	-	135,189	(84,646)	50,543
Current Risk Management Liabilities	82,433	807	19,524	102,764	(71,247)	31,517
Long-term Risk Management Liabilities	33,714	292	-	34,006	(20,108)	13,898
Total Liabilities	116,147	1,099	19,524	136,770	(91,355)	45,415
Total MTM Derivative Contract Net Assets (Liabilities)	$ 18,674	$ (731)	$ (19,524)	$ (1,581)	$ 6,709	$ 5,128

Fair Value of Derivative Instruments
December 31, 2011

I&M

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (c)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (d)
			(in thousands)			
Current Risk Management Assets	$ 154,628	$ 667	$ -	$ 155,295	$ (123,143)	$ 32,152
Long-term Risk Management Assets	68,047	58	-	68,105	(38,743)	29,362
Total Assets	222,675	725	-	223,400	(161,886)	61,514
Current Risk Management Liabilities	149,466	1,747	-	151,213	(134,233)	16,980
Long-term Risk Management Liabilities	52,441	224	10,637	63,302	(44,431)	18,871
Total Liabilities	201,907	1,971	10,637	214,515	(178,664)	35,851
Total MTM Derivative Contract Net Assets (Liabilities)	$ 20,768	$ (1,246)	$ (10,637)	$ 8,885	$ 16,778	$ 25,663

Fair Value of Derivative Instruments
December 31, 2012

OPCo

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (d)
			(in thousands)			
Current Risk Management Assets	$ 183,064	$ 464	$ -	$ 183,528	$ (139,215)	$ 44,313
Long-term Risk Management Assets	85,023	303	-	85,326	(37,038)	48,288
Total Assets	268,087	767	-	268,854	(176,253)	92,601
Current Risk Management Liabilities	171,397	1,658	-	173,055	(148,900)	24,155
Long-term Risk Management Liabilities	66,448	596	-	67,044	(41,079)	25,965
Total Liabilities	237,845	2,254	-	240,099	(189,979)	50,120
Total MTM Derivative Contract Net Assets (Liabilities)	$ 30,242	$ (1,487)	$ -	$ 28,755	$ 13,726	$ 42,481

Fair Value of Derivative Instruments
December 31, 2011

OPCo

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (c)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (d)
			(in thousands)			
Current Risk Management Assets	$ 325,904	$ 1,409	$ -	$ 327,313	$ (273,020)	$ 54,293
Long-term Risk Management Assets	136,519	122	-	136,641	(83,027)	53,614
Total Assets	462,423	1,531	-	463,954	(356,047)	107,907
Current Risk Management Liabilities	329,307	3,712	-	333,019	(296,458)	36,561
Long-term Risk Management Liabilities	112,454	474	-	112,928	(95,038)	17,890
Total Liabilities	441,761	4,186	-	445,947	(391,496)	54,451
Total MTM Derivative Contract Net Assets (Liabilities)	$ 20,662	$ (2,655)	$ -	$ 18,007	$ 35,449	$ 53,456

Fair Value of Derivative Instruments
December 31, 2012

PSO

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (d)
			(in thousands)			
Current Risk Management Assets	$ 1,657	$ 42	$ -	$ 1,699	$ (1,190)	$ 509
Long-term Risk Management Assets	-	-	-	-	31	31
Total Assets	1,657	42	-	1,699	(1,159)	540
Current Risk Management Liabilities	7,021	17	-	7,038	(1,190)	5,848
Long-term Risk Management Liabilities	-	-	-	-	31	31
Total Liabilities	7,021	17	-	7,038	(1,159)	5,879
Total MTM Derivative Contract Net Assets (Liabilities)	$ (5,364)	$ 25	$ -	$ (5,339)	$ -	$ (5,339)

Fair Value of Derivative Instruments
December 31, 2011

PSO

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (c)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (d)
			(in thousands)			
Current Risk Management Assets	$ 6,980	$ -	$ -	$ 6,980	$ (6,415)	$ 565
Long-term Risk Management Assets	914	-	-	914	(600)	314
Total Assets	7,894	-	-	7,894	(7,015)	879
Current Risk Management Liabilities	7,665	107	-	7,772	(6,492)	1,280
Long-term Risk Management Liabilities	1,930	-	-	1,930	(600)	1,330
Total Liabilities	9,595	107	-	9,702	(7,092)	2,610
Total MTM Derivative Contract Net Assets (Liabilities)	$ (1,701)	$ (107)	$ -	$ (1,808)	$ 77	$ (1,731)

Fair Value of Derivative Instruments
December 31, 2012

SWEPCo

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (d)
			(in thousands)			
Current Risk Management Assets	$ 2,804	$ 41	$ -	$ 2,845	$ (2,150)	$ 695
Long-term Risk Management Assets	-	-	-	-	-	-
Total Assets	2,804	41	-	2,845	(2,150)	695
Current Risk Management Liabilities	3,261	17	-	3,278	(2,150)	1,128
Long-term Risk Management Liabilities	-	-	-	-	-	-
Total Liabilities	3,261	17	-	3,278	(2,150)	1,128
Total MTM Derivative Contract Net Assets (Liabilities)	$ (457)	$ 24	$ -	$ (433)	$ -	$ (433)

Fair Value of Derivative Instruments
December 31, 2011

SWEPCo

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (c)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (d)
			(in thousands)			
Current Risk Management Assets	$ 6,327	$ -	$ 3	$ 6,330	$ (5,885)	$ 445
Long-term Risk Management Assets	818	-	-	818	(536)	282
Total Assets	7,145	-	3	7,148	(6,421)	727
Current Risk Management Liabilities	11,062	97	19,143	30,302	(5,943)	24,359
Long-term Risk Management Liabilities	757	-	-	757	(536)	221
Total Liabilities	11,819	97	19,143	31,059	(6,479)	24,580
Total MTM Derivative Contract Net Assets (Liabilities)	$ (4,674)	$ (97)	$ (19,140)	$ (23,911)	$ 58	$ (23,853)

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) Amounts primarily 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.
(d) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The tables below present the Registrant Subsidiaries' activity of derivative risk management contracts for the years ended December 31, 2012, 2011 and 2010:

Amount of Gain (Loss) Recognized on Risk Management Contracts Year Ended December 31, 2012

Location of Gain (Loss)	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Electric Generation, Transmission and Distribution Revenues	$ (1,149)	$ 11,437	$ 11,978	$ 163	$ 398
Sales to AEP Affiliates	-	-	-	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	-
Regulatory Assets (a)	(7,835)	(9,204)	(14,104)	(5,304)	(6,274)
Regulatory Liabilities (a)	7,314	(889)	-	(19)	(13)
Total Gain (Loss) on Risk Management Contracts	$ (1,670)	$ 1,344	$ (2,126)	$ (5,160)	$ (5,889)

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

Location of Gain (Loss)	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Electric Generation, Transmission and Distribution Revenues	$ 2,843	$ 12,786	$ 27,292	$ 297	$ 547
Sales to AEP Affiliates	154	92	196	3	4
Fuel and Other Consumables Used for Electric Generation	-	-	(2)	-	-
Regulatory Assets (a)	373	(1,470)	(17,928)	(1,421)	(1,709)
Regulatory Liabilities (a)	2,552	(5,178)	(105)	708	(118)
Total Gain (Loss) on Risk Management Contracts	$ 5,922	$ 6,230	$ 9,453	$ (413)	$ (1,276)

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

Location of Gain (Loss)	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Electric Generation, Transmission and Distribution Revenues	$ 5,057	$ 21,834	$ 40,893	$ 3,156	$ 3,880
Sales to AEP Affiliates	(2,379)	(2,471)	5,043	(794)	(1,523)
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	-
Regulatory Assets (a)	(372)	(186)	(5,788)	46	(2,902)
Regulatory Liabilities (a)	27,790	8,217	3,451	878	351
Total Gain (Loss) on Risk Management Contracts	$ 30,096	$ 27,394	$ 43,599	$ 3,286	$ (194)

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

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 (APCo, I&M, PSO and SWEPCo) 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.

The Registrant Subsidiaries record 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 Expense on the statements of income. During 2012, 2011 and 2010, the Registrant Subsidiaries 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 attributable to a particular risk), the Registrant Subsidiaries initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects Net Income. The Registrant Subsidiaries recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale 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 2012, 2011 and 2010, APCo, I&M and OPCo designated power, coal and natural gas derivatives as cash flow hedges.

The Registrant Subsidiaries reclassify gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the statements of income. During 2012, 2011 and 2010, the Registrant Subsidiaries designated heating oil and gasoline derivatives as cash flow hedges.

The Registrant Subsidiaries reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During 2012, I&M and SWEPCo designated interest rate derivatives as cash flow hedges. During 2011, APCo, I&M and SWEPCo designated interest rate derivatives as cash flow hedges. During 2010, APCo and PSO 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 (Loss) on the balance sheets into Depreciation and Amortization expense on the statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During 2012, 2011 and 2010, SWEPCo designated foreign currency derivatives as cash flow hedges.

During 2012, 2011 and 2010, hedge ineffectiveness was immaterial or nonexistent for all of the hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets and the reasons for changes in cash flow hedges for the years ended December 31, 2012, 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, 2012

Commodity Contracts	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Balance in AOCI as of December 31, 2011	$ (1,309)	$ (819)	$ (1,748)	$ (69)	$ (62)
Changes in Fair Value Recognized in AOCI	(1,310)	(987)	(2,002)	104	100
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission and Distribution Revenues	(16)	(43)	(109)	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	-
Purchased Electricity for Resale	440	1,151	3,002	-	-
Other Operation Expense	(25)	(14)	(35)	(14)	(11)
Maintenance Expense	-	(2)	(5)	1	-
Property, Plant and Equipment	(14)	(10)	(15)	(1)	(5)
Regulatory Assets (a)	1,590	278	-	-	-
Regulatory Liabilities (a)	-	-	-	-	-
Balance in AOCI as of December 31, 2012	$ (644)	$ (446)	$ (912)	$ 21	$ 22

Interest Rate and Foreign Currency Contracts	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Balance in AOCI as of December 31, 2011	$ 1,024	$ (14,465)	$ 9,454	$ 7,218	$ (15,462)
Changes in Fair Value Recognized in AOCI	-	(5,777)	-	-	(2,778)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Other Operation Expense	-	-	-	-	-
Depreciation and Amortization Expense	-	-	4	-	-
Interest Expense	1,053	595	(1,363)	(758)	2,669
Balance in AOCI as of December 31, 2012	$ 2,077	$ (19,647)	$ 8,095	$ 6,460	$ (15,571)

Total Contracts	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Balance in AOCI as of December 31, 2011	$ (285)	$ (15,284)	$ 7,706	$ 7,149	$ (15,524)
Changes in Fair Value Recognized in AOCI	(1,310)	(6,764)	(2,002)	104	(2,678)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission and Distribution Revenues	(16)	(43)	(109)	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	-
Purchased Electricity for Resale	440	1,151	3,002	-	-
Other Operation Expense	(25)	(14)	(35)	(14)	(11)
Maintenance Expense	-	(2)	(5)	1	-
Depreciation and Amortization Expense	-	-	4	-	-
Interest Expense	1,053	595	(1,363)	(758)	2,669
Property, Plant and Equipment	(14)	(10)	(15)	(1)	(5)
Regulatory Assets (a)	1,590	278	-	-	-
Regulatory Liabilities (a)	-	-	-	-	-
Balance in AOCI as of December 31, 2012	$ 1,433	$ (20,093)	$ 7,183	$ 6,481	$ (15,549)

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

Commodity Contracts	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Balance in AOCI as of December 31, 2010	$ (273)	$ (178)	$ (364)	$ 88	$ 82
Changes in Fair Value Recognized in AOCI	(2,077)	(1,294)	(2,748)	108	102
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission and Distribution Revenues	249	544	1,457	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	-
Purchased Electricity for Resale	62	79	425	-	-
Other Operation Expense	(95)	(71)	(160)	(93)	(93)
Maintenance Expense	(169)	(64)	(141)	(62)	(65)
Property, Plant and Equipment	(175)	(90)	(217)	(110)	(88)
Regulatory Assets (a)	1,169	255	-	-	-
Regulatory Liabilities (a)	-	-	-	-	-
Balance in AOCI as of December 31, 2011	$ (1,309)	$ (819)	$ (1,748)	$ (69)	$ (62)

Interest Rate and Foreign Currency Contracts	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Balance in AOCI as of December 31, 2010	$ 217	$ (8,507)	$ 10,813	$ 8,406	$ (4,272)
Changes in Fair Value Recognized in AOCI	(373)	(6,913)	-	(475)	(12,438)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Other Operation Expense	-	-	-	-	-
Depreciation and Amortization Expense	-	-	4	-	-
Interest Expense	1,180	955	(1,363)	(713)	1,248
Balance in AOCI as of December 31, 2011	$ 1,024	$ (14,465)	$ 9,454	$ 7,218	$ (15,462)

Total Contracts	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Balance in AOCI as of December 31, 2010	$ (56)	$ (8,685)	$ 10,449	$ 8,494	$ (4,190)
Changes in Fair Value Recognized in AOCI	(2,450)	(8,207)	(2,748)	(367)	(12,336)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission and Distribution Revenues	249	544	1,457	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	-
Purchased Electricity for Resale	62	79	425	-	-
Other Operation Expense	(95)	(71)	(160)	(93)	(93)
Maintenance Expense	(169)	(64)	(141)	(62)	(65)
Depreciation and Amortization Expense	-	-	4	-	-
Interest Expense	1,180	955	(1,363)	(713)	1,248
Property, Plant and Equipment	(175)	(90)	(217)	(110)	(88)
Regulatory Assets (a)	1,169	255	-	-	-
Regulatory Liabilities (a)	-	-	-	-	-
Balance in AOCI as of December 31, 2011	$ (285)	$ (15,284)	$ 7,706	$ 7,149	$ (15,524)

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

Commodity Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of December 31, 2009	$ (743)	$ (382)	$ (742)	$ (78)	$ 112
Changes in Fair Value Recognized in AOCI	(1,450)	(901)	(1,958)	77	69
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission and Distribution Revenues	51	87	229	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	(13)	197	-
Purchased Electricity for Resale	393	895	2,338	-	-
Other Operation Expense	(43)	(31)	(72)	(39)	(44)
Maintenance Expense	(70)	(28)	(54)	(24)	(23)
Property, Plant and Equipment	(71)	(36)	(87)	(45)	(32)
Regulatory Assets (a)	1,660	218	-	-	-
Regulatory Liabilities (a)	-	-	(5)	-	-
Balance in AOCI as of December 31, 2010	$ (273)	$ (178)	$ (364)	$ 88	$ 82

Interest Rate and Foreign Currency Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of December 31, 2009	$ (6,450)	$ (9,514)	$ 12,172	$ (521)	$ (5,047)
Changes in Fair Value Recognized in AOCI	5,042	-	-	8,813	(74)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Other Operation Expense	-	-	-	-	21
Depreciation and Amortization Expense	-	-	4	-	-
Interest Expense	1,625	1,007	(1,363)	114	828
Balance in AOCI as of December 31, 2010	$ 217	$ (8,507)	$ 10,813	$ 8,406	$ (4,272)

Total Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of December 31, 2009	$ (7,193)	$ (9,896)	$ 11,430	$ (599)	$ (4,935)
Changes in Fair Value Recognized in AOCI	3,592	(901)	(1,958)	8,890	(5)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission and Distribution Revenues	51	87	229	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	(13)	197	-
Purchased Electricity for Resale	393	895	2,338	-	-
Other Operation Expense	(43)	(31)	(72)	(39)	(23)
Maintenance Expense	(70)	(28)	(54)	(24)	(23)
Depreciation and Amortization Expense	-	-	4	-	-
Interest Expense	1,625	1,007	(1,363)	114	828
Property, Plant and Equipment	(71)	(36)	(87)	(45)	(32)
Regulatory Assets (a)	1,660	218	-	-	-
Regulatory Liabilities (a)	-	-	(5)	-	-
Balance in AOCI as of December 31, 2010	$ (56)	$ (8,685)	$ 10,449	$ 8,494	$ (4,190)

(a) Represents realized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets as of December 31, 2012 and 2011 were:

Impact of Cash Flow Hedges on the Registrant Subsidiaries' Balance Sheets December 31, 2012

	Hedging Assets (a)		Hedging Liabilities (a)		AOCI Gain (Loss) Net of Tax	
Company	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency
			(in thousands)			
APCo	$ 302	$ -	$ 1,355	$ -	$ (644)	$ 2,077
I&M	200	-	931	19,524	(446)	(19,647)
OPCo	416	-	1,903	-	(912)	8,095
PSO	25	-	-	-	21	6,460
SWEPCo	24	-	-	-	22	(15,571)

	Expected to be Reclassified to Net Income During the Next Twelve Months		
Company	Commodity	Interest Rate and Foreign Currency	Maximum Term for Exposure to Variability of Future Cash Flows
	(in thousands)		(in months)
APCo	$ (507)	$ (1,013)	17
I&M	(355)	(1,600)	17
OPCo	(720)	1,359	17
PSO	21	759	12
SWEPCo	22	(2,267)	12

Impact of Cash Flow Hedges on the Registrant Subsidiaries' Balance Sheets December 31, 2011

	Hedging Assets (a)		Hedging Liabilities (a)		AOCI Gain (Loss) Net of Tax	
Company	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency
			(in thousands)			
APCo	$ 431	$ -	$ 2,418	$ -	$ (1,309)	$ 1,024
I&M	277	-	1,523	10,637	(819)	(14,465)
OPCo	584	-	3,239	-	(1,748)	9,454
PSO	-	-	107	-	(69)	7,218
SWEPCo	-	3	97	19,143	(62)	(15,462)

	Expected to be Reclassified to Net Income During the Next Twelve Months	
Company	Commodity	Interest Rate and Foreign Currency
	(in thousands)	
APCo	$ (1,140)	$ (1,052)
I&M	(712)	(595)
OPCo	(1,518)	1,359
PSO	(70)	759
SWEPCo	(63)	(1,864)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the balance sheets.

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

Credit Risk

AEPSC, on behalf of the Registrant Subsidiaries, limits credit risk in their 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 the Registrant Subsidiaries, 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 the Registrant Subsidiaries, 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, the Registrant Subsidiaries are 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. The Registrant Subsidiaries have not experienced a downgrade below investment grade. The following tables represent: (a) the Registrant Subsidiaries' fair values of such derivative contracts, (b) the amount of collateral the Registrant Subsidiaries would have been required to post for all derivative and non-derivative contracts if credit ratings of the Registrant Subsidiaries had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of December 31, 2012 and 2011:

	December 31, 2012		
Company	Liabilities for Derivative Contracts with Credit Downgrade Triggers	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities
		(in thousands)	
APCo	$ 2,159	$ 3,699	$ 3,510
I&M	1,483	2,540	2,411
OPCo	3,034	5,198	4,933
PSO	-	1,509	1,429
SWEPCo	-	1,778	1,683

	December 31, 2011		
Company	Liabilities for Derivative Contracts with Credit Downgrade Triggers	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities
		(in thousands)	
APCo	$ 10,007	$ 6,211	$ 6,211
I&M	6,418	3,983	3,983
OPCo	13,550	8,410	8,410
PSO	-	856	414
SWEPCo	-	1,128	522

As of December 31, 2012 and 2011, the Registrant Subsidiaries were not required to post any collateral.

In addition, a majority of the Registrant Subsidiaries' non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following tables represent: (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 the Registrant Subsidiaries and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering the Registrant Subsidiaries' contractual netting arrangements as of December 31, 2012 and 2011:

	December 31, 2012		
Company	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)	
APCo	$ 49,465	$ 1,822	$ 30,160
I&M	53,499	1,252	40,240
OPCo	69,516	2,561	42,386
PSO	-	-	-
SWEPCo	-	-	-

	December 31, 2011		
Company	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)	
APCo	$ 76,868	$ 8,107	$ 27,603
I&M	59,936	5,200	28,339
OPCo	104,091	10,978	37,380
PSO	142	-	61
SWEPCo	19,322	-	19,220

9. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

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

The book values and fair values of Long-term Debt for the Registrant Subsidiaries as of December 31, 2012 and 2011 are summarized in the following table:

	December 31,			
	2012		2011	
Company	Book Value	Fair Value	Book Value	Fair Value
		(in thousands)		
APCo	$ 3,702,442	$ 4,555,143	$ 3,726,251	$ 4,431,912
I&M	2,057,666	2,372,017	2,057,675	2,339,344
OPCo	3,860,440	4,560,337	4,054,148	4,665,739
PSO	949,871	1,175,759	947,364	1,123,306
SWEPCo	2,046,228	2,400,509	1,728,637	2,019,094

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

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

The following is a summary of nuclear trust fund investments as of December 31, 2012 and 2011:

	December 31, 2012			December 31, 2011		
	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	$ 16,783	$ -	$ -	$ 18,229	$ -	$ -
Fixed Income Securities:						
United States Government	647,918	58,268	(747)	543,506	60,946	(547)
Corporate Debt	35,399	4,903	(1,352)	53,979	4,932	(1,536)
State and Local Government	270,090	1,006	(863)	329,986	(430)	(2,236)
Subtotal Fixed Income Securities	953,407	64,177	(2,962)	927,471	65,448	(4,319)
Equity Securities - Domestic	735,582	284,599	(76,557)	646,032	214,748	(79,536)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,705,772	$ 348,776	$ (79,519)	$ 1,591,732	$ 280,196	$ (83,855)

The following table provides the securities activity within the decommissioning and SNF trusts for the years ended December 31, 2012, 2011 and 2010:

	Years Ended December 31, 2012	2011	2010
	(in thousands)		
Proceeds from Investment Sales	$ 987,550	$ 1,110,909	$ 1,361,813
Purchases of Investments	1,045,422	1,166,690	1,414,473
Gross Realized Gains on Investment Sales	24,605	33,382	11,570
Gross Realized Losses on Investment Sales	8,881	22,159	2,087

The adjusted cost of debt securities was $889 million and $862 million as of December 31, 2012 and 2011, respectively. The adjusted cost of equity securities was $451 million and $431 million as of December 31, 2012 and 2011, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2012 was as follows:

	Fair Value of Debt Securities
	(in thousands)
Within 1 year	$ 80,993
1 year – 5 years	373,532
5 years – 10 years	265,885
After 10 years	232,997
Total	$ 953,407

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 Registrant Subsidiaries' financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2012 and 2011. 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, 2012

APCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 4,161	$ 166,916	$ 17,058	$ (123,117)	$ 65,018
Cash Flow Hedges:					
Commodity Hedges (a)	-	498	-	(196)	302
Total Risk Management Assets	$ 4,161	$ 167,414	$ 17,058	$ (123,313)	$ 65,320
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 1,959	$ 158,665	$ 6,079	$ (132,884)	$ 33,819
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,551	-	(196)	1,355
Total Risk Management Liabilities	$ 1,959	$ 160,216	$ 6,079	$ (133,080)	$ 35,174

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

APCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 4,680	$ 302,128	$ 25,423	$ (255,324)	$ 76,907
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,095	-	(664)	431
De-designated Risk Management Contracts (c)	-	-	-	1,533	1,533
Total Risk Management Assets	$ 4,680	$ 303,223	$ 25,423	$ (254,455)	$ 78,871
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 2,535	$ 291,194	$ 23,379	$ (279,997)	$ 37,111
Cash Flow Hedges:					
Commodity Hedges (a)	-	3,009	73	(664)	2,418
Total Risk Management Liabilities	$ 2,535	$ 294,203	$ 23,452	$ (280,661)	$ 39,529

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

I&M

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 2,858	$ 120,242	$ 11,717	$ (84,474)	$ 50,343
Cash Flow Hedges:					
Commodity Hedges (a)	-	330	-	(130)	200
Total Risk Management Assets	2,858	120,572	11,717	(84,604)	50,543
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (d)	6,508	-	-	10,275	16,783
Fixed Income Securities:					
United States Government	-	647,918	-	-	647,918
Corporate Debt	-	35,399	-	-	35,399
State and Local Government	-	270,090	-	-	270,090
Subtotal Fixed Income Securities	-	953,407	-	-	953,407
Equity Securities - Domestic (e)	735,582	-	-	-	735,582
Total Spent Nuclear Fuel and Decommissioning Trusts	742,090	953,407	-	10,275	1,705,772
Total Assets	$ 744,948	$ 1,073,979	$ 11,717	$ (74,329)	$ 1,756,315
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 1,346	$ 110,621	$ 4,176	$ (91,183)	$ 24,960
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,061	-	(130)	931
Interest Rate/Foreign Currency Hedges	-	19,524	-	-	19,524
Total Risk Management Liabilities	$ 1,346	$ 131,206	$ 4,176	$ (91,313)	$ 45,415

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

I&M

Assets:	Level 1	Level 2	Level 3	Other	Total
			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 3,001	$ 203,175	$ 16,305	$ (162,227)	$ 60,254
Cash Flow Hedges:					
Commodity Hedges (a)	-	702	-	(425)	277
De-designated Risk Management Contracts (c)	-	-	-	983	983
Total Risk Management Assets	3,001	203,877	16,305	(161,669)	61,514
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (d)	-	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 (e)	646,032	-	-	-	646,032
Total Spent Nuclear Fuel and Decommissioning Trusts	646,032	932,902	-	12,798	1,591,732
Total Assets	$ 649,033	$ 1,136,779	$ 16,305	$ (148,871)	$ 1,653,246
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 1,626	$ 185,092	$ 14,995	$ (178,022)	$ 23,691
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,901	47	(425)	1,523
Interest Rate/Foreign Currency Hedges	-	10,637	-	-	10,637
Total Risk Management Liabilities	$ 1,626	$ 197,630	$ 15,042	$ (178,447)	$ 35,851

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

OPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (f)	$ -	$ 26	$ -	$ 39	$ 65
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	5,848	238,254	23,973	(175,890)	92,185
Cash Flow Hedges:					
Commodity Hedges (a)	-	688	-	(272)	416
Total Risk Management Assets	5,848	238,942	23,973	(176,162)	92,601
Total Assets	$ 5,848	$ 238,968	$ 23,973	$ (176,123)	$ 92,666
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 2,753	$ 226,536	$ 8,544	$ (189,616)	$ 48,217
Cash Flow Hedges:					
Commodity Hedges (a)	-	2,175	-	(272)	1,903
Total Risk Management Liabilities	$ 2,753	$ 228,711	$ 8,544	$ (189,888)	$ 50,120

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

OPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (f)	$ 26	$ -	$ -	$ 22	$ 48
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	6,339	421,249	34,425	(356,766)	105,247
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,483	-	(899)	584
De-designated Risk Management Contracts (c)	-	-	-	2,076	2,076
Total Risk Management Assets	6,339	422,732	34,425	(355,589)	107,907
Total Assets	$ 6,365	$ 422,732	$ 34,425	$ (355,567)	$ 107,955
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 3,433	$ 406,259	$ 31,659	$ (390,139)	$ 51,212
Cash Flow Hedges:					
Commodity Hedges (a)	-	4,038	100	(899)	3,239
Total Risk Management Liabilities	$ 3,433	$ 410,297	$ 31,759	$ (391,038)	$ 54,451

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

PSO

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ -	$ 1,657	$ -	$ (1,142)	$ 515
Cash Flow Hedges:					
Commodity Hedges (a)	-	42	-	(17)	25
Total Risk Management Assets	$ -	$ 1,699	$ -	$ (1,159)	$ 540
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ -	$ 7,021	$ -	$ (1,142)	$ 5,879
Cash Flow Hedges:					
Commodity Hedges (a)	-	17	-	(17)	-
Total Risk Management Liabilities	$ -	$ 7,038	$ -	$ (1,159)	$ 5,879

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

PSO

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 97	$ 7,797	$ -	$ (7,015)	$ 879
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 53	$ 9,542	$ -	$ (7,092)	$ 2,503
Cash Flow Hedges:					
Commodity Hedges	-	107	-	-	107
Total Risk Management Liabilities	$ 53	$ 9,649	$ -	$ (7,092)	$ 2,610

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

SWEPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ -	$ 2,804	$ -	$ (2,133)	$ 671
Cash Flow Hedges:					
Commodity Hedges (a)	-	41	-	(17)	24
Total Risk Management Assets	$ -	$ 2,845	$ -	$ (2,150)	$ 695
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ -	$ 3,261	$ -	$ (2,133)	$ 1,128
Cash Flow Hedges:					
Commodity Hedges (a)	-	17	-	(17)	-
Total Risk Management Liabilities	$ -	$ 3,278	$ -	$ (2,150)	$ 1,128

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

SWEPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 122	$ 7,023	$ -	$ (6,421)	$ 724
Cash Flow Hedges:					
Interest Rate/Foreign Currency Hedges	-	3	-	-	3
Total Risk Management Assets	$ 122	$ 7,026	$ -	$ (6,421)	$ 727
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 66	$ 11,753	$ -	$ (6,479)	$ 5,340
Cash Flow Hedges:					
Commodity Hedges	-	97	-	-	97
Interest Rate/Foreign Currency Hedges	-	19,143	-	-	19,143
Total Risk Management Liabilities	$ 66	$ 30,993	$ -	$ (6,479)	$ 24,580

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(b) Substantially comprised of power contracts for APCo, I&M and OPCo and coal contracts for PSO and SWEPCo.
(c) 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.
(d) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.
(e) Amounts represent publicly traded equity securities and equity-based mutual funds.
(f) Amounts in "Other" column primarily represent cash deposits with third parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.

There have been no transfers between Level 1 and Level 2 during the years ended December 31, 2012, 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, 2012	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance as of December 31, 2011	$ 1,971	$ 1,263	$ 2,666	$ -	$ -
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(5,204)	(3,554)	(7,452)	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	-	5,401	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	23	13	28	-	-
Purchases, Issuances and Settlements (c)	11,200	7,734	16,214	-	-
Transfers into Level 3 (d) (e)	1,392	860	1,909	-	-
Transfers out of Level 3 (e) (f)	(1,930)	(1,144)	(2,527)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	3,527	2,369	(810)	-	-
Balance as of December 31, 2012	$ 10,979	$ 7,541	$ 15,429	$ -	$ -

Year Ended December 31, 2011	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance as of December 31, 2010	$ 5,131	$ 3,108	$ 6,583	$ 1	$ 2
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(2,154)	(1,261)	(2,711)	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	-	7,741	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(73)	(47)	(100)	-	-
Purchases, Issuances and Settlements (c)	1,574	847	1,858	-	-
Transfers into Level 3 (d) (e)	2,488	1,531	3,257	-	-
Transfers out of Level 3 (e) (f)	(3,003)	(1,906)	(4,032)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(1,992)	(1,009)	(9,930)	(1)	(2)
Balance as of December 31, 2011	$ 1,971	$ 1,263	$ 2,666	$ -	$ -

Year Ended December 31, 2010	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance as of December 31, 2009	$ 9,428	$ 4,816	$ 10,345	$ 2	$ 3
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	1,670	963	2,053	2	2
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	-	21,314	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-	-	-
Purchases, Issuances and Settlements (c)	(7,163)	(4,121)	(8,800)	(1)	(1)
Transfers into Level 3 (d) (e)	1,133	616	1,333	-	-
Transfers out of Level 3 (e) (f)	(10,999)	(6,558)	(13,978)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	11,062	7,392	(5,684)	(2)	(2)
Balance as of December 31, 2010	$ 5,131	$ 3,108	$ 6,583	$ 1	$ 2

(a) Included in revenues on the statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Represents existing assets or liabilities that were previously categorized as Level 3.
(g) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory assets/liabilities.

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

APCo	**Fair Value Assets**	**Fair Value Liabilities**	**Valuation Technique**	**Significant Unobservable Input (a)**	**Forward Price Range Low**	**Forward Price Range High**
	(in thousands)					
Energy Contracts	$ 15,310	$ 3,920	Discounted Cash Flow	Forward Market Price	$ 9.40	$ 68.80
FTRs	1,748	2,159	Discounted Cash Flow	Forward Market Price	(3.21)	14.79
Total	$ 17,058	$ 6,079				

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

OPCo	**Fair Value Assets**	**Fair Value Liabilities**	**Valuation Technique**	**Significant Unobservable Input (a)**	**Forward Price Range Low**	**Forward Price Range High**
	(in thousands)					
Energy Contracts	$ 21,516	$ 5,510	Discounted Cash Flow	Forward Market Price	$ 9.40	$ 68.80
FTRs	2,457	3,034	Discounted Cash Flow	Forward Market Price	(3.21)	14.79
Total	$ 23,973	$ 8,544				

(a) Represents market prices in dollars per MWh.

10. INCOME TAXES

The details of the Registrant Subsidiaries' income taxes as reported are as follows:

Year Ended December 31, 2012	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
			(in thousands)		
Income Tax Expense (Credit):					
Current	$ 28,307	$ (9,221)	$ 100,447	$ 18,634	$ (214,353)
Deferred	138,460	53,067	45,685	48,916	260,761
Deferred Investment Tax Credits	(1,240)	(4,502)	(1,849)	(856)	(550)
Income Tax Expense	$ 165,527	$ 39,344	$ 144,283	$ 66,694	$ 45,858

Year Ended December 31, 2011	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
			(in thousands)		
Income Tax Expense (Credit):					
Current	$ (15,136)	$ (86,471)	$ 96,893	$ 6,904	$ 40,727
Deferred	107,565	141,014	119,184	61,581	16,726
Deferred Investment Tax Credits	(2,569)	(2,783)	(2,380)	(856)	(550)
Income Tax Expense	$ 89,860	$ 51,760	$ 213,697	$ 67,629	$ 56,903

Year Ended December 31, 2010	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
			(in thousands)		
Income Tax Expense (Credit):					
Current	$ (66,216)	$ 1,795	$ 11,403	$ (46,528)	$ (16,066)
Deferred	144,413	63,947	292,831	92,695	81,764
Deferred Investment Tax Credits	(3,967)	(2,316)	(2,928)	3,933	(1,484)
Income Tax Expense	$ 74,230	$ 63,426	$ 301,306	$ 50,100	$ 64,214

Shown below for each Registrant Subsidiary 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:

APCo	**Years Ended December 31,**		
	2012	**2011**	**2010**
		(in thousands)	
Net Income	$ 257,503	$ 162,758	$ 136,668
Income Tax Expense	165,527	89,860	74,230
Pretax Income	$ 423,030	$ 252,618	$ 210,898
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 148,061	$ 88,416	$ 73,814
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	20,424	17,923	18,134
Investment Tax Credits, Net	(1,240)	(2,569)	(3,967)
State and Local Income Taxes, Net	3,175	(35,532)	(7,189)
Removal Costs	(6,641)	(4,447)	(6,709)
AFUDC	(1,145)	(5,314)	(1,860)
Medicare Subsidy	382	4,908	(1,159)
Valuation Allowance	5,674	30,541	-
Other	(3,163)	(4,066)	3,166
Income Tax Expense	$ 165,527	$ 89,860	$ 74,230
Effective Income Tax Rate	39.1 %	35.6 %	35.2 %

I&M	**Years Ended December 31,**		
	2012	**2011**	**2010**
		(in thousands)	
Net Income	$ 118,457	$ 149,674	$ 126,091
Income Tax Expense	39,344	51,760	63,426
Pretax Income	$ 157,801	$ 201,434	$ 189,517
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 55,230	$ 70,502	$ 66,331
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	8,659	7,895	11,419
Investment Tax Credits, Net	(4,502)	(2,783)	(2,316)
State and Local Income Taxes, Net	(1,559)	(1,376)	3,966
Removal Costs	(5,490)	(5,566)	(3,663)
AFUDC	(7,218)	(9,223)	(9,032)
Nuclear Fuel Disposal Costs	225	(1,400)	(1,655)
Other	(6,001)	(6,289)	(1,624)
Income Tax Expense	$ 39,344	$ 51,760	$ 63,426
Effective Income Tax Rate	24.9 %	25.7 %	33.5 %

OPCo

	Years Ended December 31, 2012	2011	2010
		(in thousands)	
Net Income	$ 343,534	$ 464,993	$ 541,616
Income Tax Expense	144,283	213,697	301,306
Pretax Income	$ 487,817	$ 678,690	$ 842,922
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 170,736	$ 237,542	$ 295,023
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	5,239	6,368	11,443
Investment Tax Credits, Net	(1,849)	(2,380)	(2,928)
State and Local Income Taxes, Net	(18,291)	(3,222)	906
Parent Company Loss Benefit	(11,915)	(7,117)	(9,583)
Other	363	(17,494)	6,445
Income Tax Expense	$ 144,283	$ 213,697	$ 301,306
Effective Income Tax Rate	29.6 %	31.5 %	35.7 %

PSO

	Years Ended December 31, 2012	2011	2010
		(in thousands)	
Net Income	$ 114,141	$ 124,628	$ 72,787
Income Tax Expense	66,694	67,629	50,100
Pretax Income	$ 180,835	$ 192,257	$ 122,887
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 63,292	$ 67,290	$ 43,010
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	(10)	(165)	(166)
Investment Tax Credits, Net	(781)	(781)	(781)
State and Local Income Taxes, Net	6,953	4,744	10,307
Other	(2,760)	(3,459)	(2,270)
Income Tax Expense	$ 66,694	$ 67,629	$ 50,100
Effective Income Tax Rate	36.9 %	35.2 %	40.8 %

SWEPCo

	Years Ended December 31, 2012	2011	2010
		(in thousands)	
Net Income	$ 202,513	$ 165,126	$ 146,684
Income Tax Expense	45,858	56,903	64,214
Pretax Income	$ 248,371	$ 222,029	$ 210,898
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 86,930	$ 77,710	$ 73,814
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	2,105	(7)	1,223
Depletion	(3,276)	(1,506)	(1,506)
Investment Tax Credits, Net	(550)	(550)	(1,484)
State and Local Income Taxes, Net	(18,010)	4,004	(637)
AFUDC	(19,879)	(16,962)	(15,856)
Other	(1,462)	(5,786)	8,660
Income Tax Expense	$ 45,858	$ 56,903	$ 64,214
Effective Income Tax Rate	18.5 %	25.6 %	30.4 %

The following tables show elements of the net deferred tax liability and significant temporary differences for each Registrant Subsidiary:

APCo

	December 31, 2012	December 31, 2011
	(in thousands)	
Deferred Tax Assets	$ 526,665	$ 591,379
Deferred Tax Liabilities	(2,467,063)	(2,341,814)
Net Deferred Tax Liabilities	$ (1,940,398)	$ (1,750,435)
Property Related Temporary Differences	$ (1,416,426)	$ (1,303,698)
Amounts Due from Customers for Future Federal Income Taxes	(100,520)	(95,960)
Deferred State Income Taxes	(230,490)	(235,296)
Regulatory Assets	(161,274)	(194,161)
Postretirement Benefits	45,044	61,109
Accrued Pensions	41,643	45,782
Deferred Income Taxes on Other Comprehensive Loss	16,099	31,523
Deferred Fuel and Purchased Power	(115,900)	(131,137)
Net Operating Loss Carryforward	69,580	88,721
Tax Credit Carryforward	13,199	37,850
Valuation Allowance	(36,215)	(30,541)
All Other, Net	(65,138)	(24,627)
Net Deferred Tax Liabilities	$ (1,940,398)	$ (1,750,435)

I&M

	December 31, 2012	December 31, 2011
	(in thousands)	
Deferred Tax Assets	$ 831,724	$ 773,679
Deferred Tax Liabilities	(1,842,791)	(1,700,182)
Net Deferred Tax Liabilities	$ (1,011,067)	$ (926,503)
Property Related Temporary Differences	$ (351,682)	$ (305,400)
Amounts Due from Customers for Future Federal Income Taxes	(37,633)	(28,551)
Deferred State Income Taxes	(112,388)	(107,497)
Deferred Income Taxes on Other Comprehensive Loss	15,553	15,196
Accrued Nuclear Decommissioning	(475,223)	(435,916)
Postretirement Benefits	27,323	51,037
Net Operating Loss Carryforward	31,233	12,986
Accrued Pensions	24,746	27,819
Regulatory Assets	(88,696)	(116,474)
All Other, Net	(44,300)	(39,703)
Net Deferred Tax Liabilities	$ (1,011,067)	$ (926,503)

OPCo

	December 31, 2012	December 31, 2011
	(in thousands)	
Deferred Tax Assets	$ 505,003	$ 574,007
Deferred Tax Liabilities	(2,851,068)	(2,834,046)
Net Deferred Tax Liabilities	$ (2,346,065)	$ (2,260,039)
Property Related Temporary Differences	$ (2,061,841)	$ (1,966,581)
Amounts Due from Customers for Future Federal Income Taxes	(59,291)	(59,699)
Deferred State Income Taxes	(90,001)	(98,093)
Regulatory Assets	(190,273)	(205,925)
Postretirement Benefits	50,421	74,447
Accrued Pensions	(43,928)	(30,853)
Deferred Income Taxes on Other Comprehensive Loss	89,236	106,466
Impairment Loss	100,459	-
Deferred Fuel and Purchased Power	(199,997)	(194,509)
All Other, Net	59,150	114,708
Net Deferred Tax Liabilities	$ (2,346,065)	$ (2,260,039)

PSO

	December 31, 2012	December 31, 2011
	(in thousands)	
Deferred Tax Assets	$ 101,561	$ 121,181
Deferred Tax Liabilities	(835,054)	(840,631)
Net Deferred Tax Liabilities	$ (733,493)	$ (719,450)
Property Related Temporary Differences	$ (640,859)	$ (626,456)
Amounts Due from Customers for Future Federal Income Taxes	(1,325)	(1,023)
Deferred State Income Taxes	(95,378)	(89,605)
Regulatory Assets	(57,367)	(77,016)
Postretirement Benefits	13,541	25,607
Accrued Pensions	7,570	12,978
Deferred Income Taxes on Other Comprehensive Loss	(3,489)	(3,849)
Deferred Federal Income Taxes on Deferred State Income Taxes	39,050	36,018
Net Operating Loss Carryforward	3,892	5,247
Tax Credit Carryforward	401	6,872
All Other, Net	471	(8,223)
Net Deferred Tax Liabilities	$ (733,493)	$ (719,450)

SWEPCo

	December 31, 2012	December 31, 2011
	(in thousands)	
Deferred Tax Assets	$ 286,133	$ 143,200
Deferred Tax Liabilities	(1,260,281)	(800,673)
Net Deferred Tax Liabilities	$ (974,148)	$ (657,473)
Property Related Temporary Differences	$ (997,337)	$ (588,612)
Amounts Due from Customers for Future Federal Income Taxes	(43,090)	(36,289)
Deferred State Income Taxes	(98,630)	(70,211)
Regulatory Assets	(12,922)	(35,349)
Postretirement Benefits	13,039	21,654
Accrued Pensions	5,061	5,861
Deferred Income Taxes on Other Comprehensive Loss	9,618	14,440
Impairment Loss - Turk Plant	21,700	17,150
Net Operating Loss Carryforward	104,738	-
All Other, Net	23,675	13,883
Net Deferred Tax Liabilities	$ (974,148)	$ (657,473)

AEP System Tax Allocation Agreement

The Registrant Subsidiaries join in the filing of a consolidated federal income tax return with their 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

The Registrant Subsidiaries are no longer subject to U.S. federal examination for years before 2009. The Registrant 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 materially impact the Registrant Subsidiaries' 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, the Registrant Subsidiaries accrue interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

The Registrant Subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine their tax returns and the Registrant 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, the Registrant Subsidiaries are no longer subject to state or local income tax examinations by tax authorities for years before 2008. In March 2012, AEP settled all outstanding franchise tax issues with the state of Ohio for the years 2000 through 2009. The settlements did not materially impact the Registrants Subsidiaries' net income, cash flows or financial condition.

Net Income Tax Operating Loss Carryforward

In 2011, APCo and I&M recognized federal net income tax operating losses of $313 million and $123 million, respectively, driven primarily by bonus depreciation, pension plan contributions and other book versus tax temporary differences. In 2012, SWEPCo recognized a federal net income tax operating loss of $858 million driven primarily by bonus depreciation. APCo, OPCo, PSO and SWEPCo also had state net income tax operating loss carryforwards as indicated in the table below.

Company	State	State Net Income Tax Operating Loss Carryforward (in thousands)	Year of Expiration
APCo	Tennessee	$ 12,513	2026
APCo	Virginia	328,850	2031
APCo	West Virginia	583,890	2032
OPCo	West Virginia	312,791	2032
PSO	Oklahoma	99,792	2031
SWEPCo	Louisiana	313,750	2027

As a result, APCo, I&M, OPCo, PSO and SWEPCo accrued deferred federal and/or state and local income tax benefits in 2011 and/or 2012 and expect to realize the federal, state and local 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 2032.

Tax Credit Carryforward

Federal and state net income tax operating losses sustained in 2011 and 2009 along with lower federal and state taxable income in 2010 resulted in unused federal and state income tax credits. As of December 31, 2012, the Registrant Subsidiaries have federal tax credit carryforwards and APCo and PSO have state 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 and state coal tax credits will expire in the years 2013 through 2021.

Company	Total Federal Tax Credit Carryforward	Federal Tax Credit Carryforward Subject to Expiration	Total State Tax Credit Carryforward	State Tax Credit Carryforward Subject to Expiration
		(in thousands)		
APCo	$ 12,692	$ 4,476	$ 65,653	$ 29,297
I&M	2,487	2,487	-	-
OPCo	21,321	1,548	-	-
PSO	401	381	16,194	-
SWEPCo	2,537	899	-	-

The Registrant Subsidiaries anticipate future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused. APCo does not anticipate that state taxable income will be sufficient in future periods to realize the tax benefits of all state tax credits before they expire unused and a valuation allowance has been provided accordingly.

Valuation Allowance

Management assesses past results and future operations to estimate and evaluate available positive and negative evidence to evaluate whether sufficient future taxable income will be generated to use existing deferred tax assets. A significant piece of objective negative information evaluated were the net income tax operating losses sustained in 2012, 2011 and 2009. On the basis of this evaluation of available positive and negative evidence, as of December 31, 2012, a valuation allowance of $36.2 million for state tax credits, net of federal tax, has been recorded by APCo in order to measure only the portion of the deferred tax assets that, more likely than not, will be realized. The amount of the deferred tax assets considered realizable, however, could be adjusted if estimates of future taxable income during the carryforward period are reduced or if objective negative evidence in the form of cumulative losses is no longer present and additional weight may be given to subjective evidence, such as projections for growth.

Uncertain Tax Positions

The Registrant Subsidiaries recognize interest accruals related to uncertain tax positions in interest income or expense as applicable and penalties in Other Operation expense in accordance with the accounting guidance for "Income Taxes."

The following tables show amounts reported for interest expense, interest income and reversal of prior period interest expense:

	Years Ended December 31,					
	2012			2011		
Company	Interest Expense	Interest Income	Reversal of Prior Period Interest Expense	Interest Expense	Interest Income	Reversal of Prior Period Interest Expense
	(in thousands)					
APCo	$ 62	$ -	$ 183	$ 737	$ 3,229	$ 2,416
I&M	1,355	-	-	-	2,681	638
OPCo	266	-	504	1,213	5,173	4,019
PSO	259	-	294	239	344	3,123
SWEPCo	286	-	271	1,382	1,991	2,255

	Year Ended December 31, 2010		
Company	Interest Expense	Interest Income	Reversal of Prior Period Interest Expense
	(in thousands)		
APCo	$ 2,330	$ -	$ 1,146
I&M	-	209	159
OPCo	3,948	-	1,653
PSO	455	-	871
SWEPCo	749	-	320

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

	December 31,	
Company	2012	2011
	(in thousands)	
APCo	$ -	$ 70
I&M	-	759
OPCo	-	869
PSO	15	134
SWEPCo	-	452

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

	December 31,	
Company	2012	2011
	(in thousands)	
APCo	$ 271	$ 120
I&M	1,337	145
OPCo	451	1,513
PSO	424	426
SWEPCo	1,061	668

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

	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Balance as of January 1, 2012	$ 7,311	$ 14,071	$ 43,565	$ 3,585	$ 9,031
Increase - Tax Positions Taken During a Prior Period	-	2,266	1,360	421	2,806
Decrease - Tax Positions Taken During a Prior Period	(384)	(1,252)	(13,582)	(92)	(775)
Increase - Tax Positions Taken During the Current Year	-	-	-	-	-
Decrease - Tax Positions Taken During the Current Year	-	-	-	-	-
Decrease - Settlements with Taxing Authorities	(1,674)	-	(20,291)	-	-
Decrease - Lapse of the Applicable Statute of Limitations	-	-	-	(1,641)	(1,509)
Balance as of December 31, 2012	$ 5,253	$ 15,085	$ 11,052	$ 2,273	$ 9,553

	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Balance as of January 1, 2011	$ 13,267	$ 17,871	$ 68,655	$ 9,845	$ 14,410
Increase - Tax Positions Taken During a Prior Period	5,990	9,256	11,330	1,339	14,355
Decrease - Tax Positions Taken During a Prior Period	(2,100)	(8,622)	(20,299)	(1,171)	(2,706)
Increase - Tax Positions Taken During the Current Year	-	-	-	-	-
Decrease - Tax Positions Taken During the Current Year	-	-	-	-	-
Decrease - Settlements with Taxing Authorities	(2,587)	(1,424)	(6,935)	(1,178)	(12,997)
Decrease - Lapse of the Applicable Statute of Limitations	(7,259)	(3,010)	(9,186)	(5,250)	(4,031)
Balance as of December 31, 2011	$ 7,311	$ 14,071	$ 43,565	$ 3,585	$ 9,031

	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Balance as of January 1, 2010	$ 17,292	$ 20,007	$ 65,551	$ 12,216	$ 10,163
Increase - Tax Positions Taken During a Prior Period	4,177	4,964	19,214	151	6,128
Decrease - Tax Positions Taken During a Prior Period	(6,376)	(5,287)	(8,837)	(1,200)	(376)
Increase - Tax Positions Taken During the Current Year	-	-	-	-	-
Decrease - Tax Positions Taken During the Current Year	(1,015)	(1,487)	(1,749)	(517)	(691)
Decrease - Settlements with Taxing Authorities	(811)	(236)	(70)	(265)	(4)
Decrease - Lapse of the Applicable Statute of Limitations	-	(90)	(5,454)	(540)	(810)
Balance as of December 31, 2010	$ 13,267	$ 17,871	$ 68,655	$ 9,845	$ 14,410

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 for each Registrant Subsidiary was as follows:

Company	2012	2011	2010
		(in thousands)	
APCo	$ -	$ 806	$ 1,109
I&M	1,220	654	1,664
OPCo	674	21,177	28,749
PSO	818	1,882	1,977
SWEPCo	3,512	3,717	2,481

Federal Tax Legislation – Affecting APCo, I&M, OPCo, PSO and SWEPCo

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 materially impact the Registrants Subsidiaries' 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 to the Registrant Subsidiaries as follows:

Company	(in thousands)
APCo	$ 170,466
I&M	78,456
OPCo	141,111
PSO	10,741
SWEPCo	-

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. Due to 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 by the Registrant Subsidiaries in March 2010. This reduction did not materially impact the Registrant Subsidiaries' cash flows or financial condition. For the year ended December 31, 2010, the Registrant Subsidiaries reflected a decrease in deferred tax assets, which was partially offset by recording net tax regulatory assets in jurisdictions with regulated operations, resulting in a decrease in net income as follows:

Company	Net Reduction to Deferred Tax Assets	Tax Regulatory Assets, Net	Decrease in Net Income
		(in thousands)	
APCo	$ 9,397	$ 8,831	$ 566
I&M	7,212	6,528	684
OPCo	12,771	6,990	5,781
PSO	3,172	3,172	-
SWEPCo	3,412	3,412	-

The Small Business Jobs Act (the 2010 Act) was enacted in September 2010. Included in the 2010 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 2010 Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2011 and 2010. The enacted provisions did not materially impact the Registrant Subsidiaries' net income or financial condition but had a favorable impact on cash flows in 2010 as follows:

Company		(in thousands)
APCo	$	43,379
I&M		49,740
OPCo		124,637
PSO		-
SWEPCo		30,269

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. In November 2012, the effective date was moved to tax years beginning in 2014. Further, the notice stated that the U. S. Treasury Department anticipates that the final regulations will contain changes from the temporary regulations. Management will evaluate the impact of these regulations once they are issued.

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

State Tax Legislation – Affecting APCo, I&M and OPCo

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 8.5% Indiana corporate income tax rate will be reduced 0.5% each year beginning after June 30, 2012 with the final reduction occurring in years beginning after June 30, 2015.

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 2012, the state of West Virginia achieved certain minimum levels of shortfall reserve funds. As a result, the West Virginia corporate income tax rate will be reduced from 7.75% to 7.0% in 2013. The enacted provisions will not materially impact the Registrant Subsidiaries' net income, cash flows or financial condition.

11. LEASES

Leases of property, plant and equipment are for periods up to 60 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 Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Additionally, for regulated operations with capital leases, a capital lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

Year Ended December 31, 2012	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Net Lease Expense on Operating Leases	$ 15,633	$ 95,509	$ 59,836	$ 5,283	$ 5,797
Amortization of Capital Leases	7,429	8,429	10,906	3,839	14,793
Interest on Capital Leases	1,782	1,738	3,307	815	9,041
Total Lease Rental Costs	$ 24,844	$ 105,676	$ 74,049	$ 9,937	$ 29,631

Year Ended December 31, 2011	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Net Lease Expense on Operating Leases	$ 13,488	$ 94,317	$ 59,983	$ 6,532	$ 5,990
Amortization of Capital Leases	7,880	8,762	13,118	4,438	12,694
Interest on Capital Leases	1,898	2,115	3,753	1,098	9,651
Total Lease Rental Costs	$ 23,266	$ 105,194	$ 76,854	$ 12,068	$ 28,335

Year Ended December 31, 2010	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Net Lease Expense on Operating Leases	$ 18,034	$ 91,973	$ 62,887	$ 2,649	$ 5,877
Amortization of Capital Leases	7,002	31,178	12,069	3,992	11,742
Interest on Capital Leases	1,598	2,298	3,132	1,057	9,892
Total Lease Rental Costs	$ 26,634	$ 125,449	$ 78,088	$ 7,698	$ 27,511

The following table shows the property, plant and equipment under capital leases and related obligations recorded on the Registrant Subsidiaries' balance sheets. For SWEPCo, current and long-term capital lease obligations are included in Obligations Under Capital Leases on SWEPCo's balance sheets. For all other Registrant Subsidiaries, current capital lease obligations are included in Other Current Liabilities and long-term capital lease obligations are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets.

December 31, 2012	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Property, Plant and Equipment Under Capital Leases:					
Generation	$ 11,798	$ 19,102	$ 39,080	$ 3,624	$ 27,745
Other Property, Plant and Equipment	20,944	22,697	35,666	15,614	154,166
Total Property, Plant and Equipment	32,742	41,799	74,746	19,238	181,911
Accumulated Amortization	10,282	13,154	27,513	6,738	50,440
Net Property, Plant and Equipment Under Capital Leases	$ 22,460	$ 28,645	$ 47,233	$ 12,500	$ 131,471
Obligations Under Capital Leases:					
Noncurrent Liability	$ 16,375	$ 22,842	$ 36,381	$ 8,864	$ 114,161
Liability Due Within One Year	6,085	5,803	14,707	3,636	17,599
Total Obligations Under Capital Leases	$ 22,460	$ 28,645	$ 51,088	$ 12,500	$ 131,760

December 31, 2011	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Property, Plant and Equipment Under Capital Leases:					
Generation	$ 11,712	$ 16,100	$ 36,689	$ 3,617	$ 20,453
Other Property, Plant and Equipment	25,201	27,712	36,264	16,441	145,273
Total Property, Plant and Equipment	36,913	43,812	72,953	20,058	165,726
Accumulated Amortization	9,886	12,779	22,075	5,196	38,163
Net Property, Plant and Equipment Under Capital Leases	$ 27,027	$ 31,033	$ 50,878	$ 14,862	$ 127,563
Obligations Under Capital Leases:					
Noncurrent Liability	$ 19,293	$ 23,117	$ 40,152	$ 11,101	$ 112,802
Liability Due Within One Year	7,734	7,916	14,096	3,761	15,058
Total Obligations Under Capital Leases	$ 27,027	$ 31,033	$ 54,248	$ 14,862	$ 127,860

Future minimum lease payments consisted of the following as of December 31, 2012:

Capital Leases	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
2013	$ 6,988	$ 6,827	$ 13,669	$ 4,222	$ 25,706
2014	4,596	5,649	10,371	3,149	23,702
2015	3,849	4,279	7,383	1,921	21,585
2016	3,372	3,504	6,743	1,636	18,728
2017	2,809	3,344	6,322	1,646	20,103
Later Years	3,748	11,781	17,905	1,709	60,112
Total Future Minimum Lease Payments	25,362	35,384	62,393	14,283	169,936
Less Estimated Interest Element	2,902	6,739	11,305	1,782	38,176
Estimated Present Value of Future Minimum Lease Payments	$ 22,460	$ 28,645	$ 51,088	$ 12,501	$ 131,760

Noncancelable Operating Leases	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
2013	$ 15,693	$ 98,719	$ 58,968	$ 2,383	$ 5,893
2014	13,959	98,673	55,261	1,858	4,279
2015	11,054	97,266	52,287	1,524	3,672
2016	10,270	89,872	46,002	1,231	3,030
2017	9,819	84,142	42,678	1,048	2,681
Later Years	47,613	423,279	68,094	1,723	10,297
Total Future Minimum Lease Payments	$ 108,408	$ 891,951	$ 323,290	$ 9,767	$ 29,852

Master Lease Agreements

The Registrant Subsidiaries lease certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, the Registrant Subsidiaries are committed to pay the difference between the actual fair value and the residual value guarantee. As of December 31, 2012, the maximum potential loss by Registrant Subsidiary for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term is as follows:

Company	Maximum Potential Loss
	(in thousands)
APCo	$ 3,463
I&M	2,432
OPCo	4,003
PSO	1,171
SWEPCo	2,405

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, 2012 are as follows:

Future Minimum Lease Payments	I&M
	(in millions)
2013	$ 74
2014	74
2015	74
2016	74
2017	74
Later Years	369
Total Future Minimum Lease Payments	$ 739

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 operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $14 million for I&M and $15 million for SWEPCo for the remaining railcars as of December 31, 2012. These obligations are 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 and

SWEPCo have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is approximately $12 million and SWEPCo's is approximately $13 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.

Sabine Dragline Lease

During 2009, Sabine, an entity consolidated in accordance with the accounting guidance for "Variable Interest Entities," entered into capital lease arrangements with a nonaffiliated company to finance the purchase of two electric draglines to be used for Sabine's mining operations totaling $47 million. The amounts included in the lease represented the aggregate fair value of the existing equipment and a sale-and-leaseback transaction for additional dragline rebuild costs required to keep the dragline operational. These capital lease assets are included in Other Property, Plant and Equipment on SWEPCo's December 31, 2012 and 2011 balance sheets. The short-term and long-term capital lease obligations are included in Obligations Under Capital Leases on SWEPCo's December 31, 2012 and 2011 balance sheets. The future payment obligations are included in SWEPCo's future minimum lease payments schedule earlier in this note.

I&M 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 had a variable rate based on one month LIBOR and was accounted for as a capital lease with lease terms up to 60 months. This lease was terminated with the March 2012 refueling.

12. FINANCING ACTIVITIES

Preferred Stock

In December 2011, the Registrant Subsidiaries redeemed all of their outstanding preferred stock, resulting in a loss, which is included in Preferred Stock Dividend Requirements Including Capital Stock Expense on the statements of income. The par value of preferred stock redeemed and the loss recorded by the Registrant Subsidiaries was as follows:

Company	Par Value of Stock Redeemed	Loss on Redemption
	(in thousands)	
APCo	$ 17,736	$ 1,013
I&M	8,072	314
OPCo	16,613	488
PSO	4,882	254
SWEPCo	4,694	369

Company	Series	Number of Shares Redeemed Years Ended December 31, 2011	2010
APCo	4.50 %	177,465	53
I&M	4.12 %	11,055	-
I&M	4.125 %	55,257	44
I&M	4.56 %	14,412	-
OPCo	4.08 %	14,495	100
OPCo	4.20 %	22,824	-
OPCo	4.40 %	31,482	-
OPCo	4.50 %	97,357	6
PSO	4.00 %	44,508	-
PSO	4.24 %	4,310	3,759
SWEPCo	4.28 %	7,386	-
SWEPCo	4.65 %	1,907	-
SWEPCo	5.00 %	37,665	8

Long-term Debt

There are certain limitations on establishing liens against the Registrant Subsidiaries' assets under their respective indentures. None of the long-term debt obligations of the Registrant Subsidiaries have been guaranteed or secured by AEP or any of its affiliates.

The following details long-term debt outstanding as of December 31, 2012 and 2011:

Company	Maturity	Weighted Average Interest Rate as of December 31, 2012	Interest Rate Ranges as of December 31, 2012	2011	Outstanding as of December 31, 2012	2011
Senior Unsecured Notes					(in thousands)	
APCo	2012-2038	5.43%	0.685%-7.95%	3.40%-7.95%	$ 3,167,559	$ 3,141,843
I&M	2012-2037	6.24%	5.05%-7.00%	5.05%-7.00%	1,171,080	1,270,599
OPCo	2012-2035	5.84%	4.85%-6.60%	0.955%-6.60%	3,142,615	3,291,823
PSO	2016-2037	5.52%	4.40%-6.625%	4.40%-6.625%	896,364	896,023
SWEPCo	2015-2040	5.56%	3.55%-6.45%	4.90%-6.45%	1,822,653	1,548,437
Pollution Control Bonds (a)						
APCo	2012-2038 (b)	2.01%	0.12%-5.375%	0.07%-6.05%	532,500	582,000
I&M	2012-2025 (b)	4.03%	0.11%-6.25%	0.06%-6.25%	266,531	266,494
OPCo	2012-2038 (b)	3.72%	0.13%-5.80%	0.07%-5.80%	517,825	562,325
PSO	2014-2020	5.03%	4.45%-5.25%	4.45%-5.25%	46,360	46,360
SWEPCo	2015-2018	4.28%	3.25%-4.95%	3.25%-4.95%	135,200	135,200
Notes Payable - Affiliated						
OPCo	2015	5.25%	5.25%	5.25%	200,000	200,000
Notes Payable - Nonaffiliated						
I&M	2013-2016	2.42%	1.913%-5.44%	2.029%-5.44%	224,376	234,590
SWEPCo	2012-2032	5.09%	4.58%-6.37%	6.37%-7.03%	88,375	45,000
Spent Nuclear Fuel Obligation (c)						
I&M					265,249	265,065
Other Long-term Debt						
APCo	2026	13.718%	13.718%	13.718%	2,383	2,408
I&M (d)	2015-2025	2.39%	1.72%-6.00%	6.00%	130,430	20,927
PSO	2027	3.00%	3.00%	3.00%	7,147	4,981

(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 purposes as Long-term Debt Due Within One Year – Nonaffiliated on the balance sheets.

(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).

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

Long-term debt outstanding as of December 31, 2012 is payable as follows:

	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
2013	$ 574,679	$ 203,953	$ 856,000	$ 764	$ 3,250
2014	100,033	353,946	403,580	34,115	3,250
2015	500,038	253,730	286,000	427	306,750
2016	65,393	4,158	350,000	150,440	3,250
2017	250,049	1,479	-	454	253,250
After 2017	2,219,692	1,244,789	1,972,245	767,307	1,478,825
Principal Amount	3,709,884	2,062,055	3,867,825	953,507	2,048,575
Unamortized Discount, Net	(7,442)	(4,389)	(7,385)	(3,636)	(2,347)
Total Long-term Debt Outstanding	$ 3,702,442	$ 2,057,666	$ 3,860,440	$ 949,871	$ 2,046,228

In January 2013 and February 2013, I&M retired $12 million and $11 million, respectively, of Notes Payable related to DCC Fuel.

In February 2013, OPCo retired $250 million of 5.5% Senior Unsecured Notes due in 2013.

As of December 31, 2012, trustees held, on behalf of OPCo, $463 million of its reacquired Pollution Control Bonds.

Dividend Restrictions

The Registrant Subsidiaries pay dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the Registrant Subsidiaries to transfer funds to Parent in the form of dividends.

Federal Power Act

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

Additionally, the Federal Power Act creates a reserve on earnings attributable to hydroelectric generating plants. Because of their respective ownership of such plants, this reserve applies to APCo, I&M and OPCo.

None of these restrictions limit the ability of the Registrant Subsidiaries to pay dividends out of retained earnings.

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, APCo, I&M and OPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. As of December 31, 2012, $32 million of APCo's retained earnings and none of I&M's or OPCo'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 AEP's 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 (borrowings) to/from the Utility Money Pool as of December 31, 2012 and 2011 is included in Advances to/from Affiliates on each of the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and their corresponding authorized borrowing limits for the years ended December 31, 2012 and 2011 are described in the following tables:

Year Ended December 31, 2012:

Company	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Net Loans (Borrowings) to/from Utility Money Pool as of December 31, 2012	Authorized Short-term Borrowing Limit
			(in thousands)			
APCo	$ 350,153	$ 23,504	$ 161,363	$ 22,821	$ (150,941)	$ 600,000
I&M	-	362,733	-	202,439	116,977	500,000
OPCo	126,975	290,356	47,820	105,154	116,422	600,000
PSO	-	177,778	-	92,697	10,558	300,000
SWEPCo	227,087	173,778	147,338	78,994	153,829	350,000

Year Ended December 31, 2011:

Company	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Net Loans (Borrowings) to/from Utility Money Pool as of December 31, 2011	Authorized Short-term Borrowing Limit
			(in thousands)			
APCo	$ 217,876	$ 393,811	$ 117,378	$ 96,186	$ (176,240)	$ 600,000
I&M	57,352	219,386	23,793	56,999	95,714	500,000
OPCo	46,761	452,187	31,365	225,728	219,458	600,000
PSO	96,034	255,611	41,971	88,805	39,876	300,000
SWEPCo	136,752	105,184	47,232	38,798	(132,473)	350,000

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

	Years Ended December 31, 2012	2011	2010
Maximum Interest Rate	0.56 %	0.56 %	0.55 %
Minimum Interest Rate	0.39 %	0.06 %	0.09 %

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the years ended December 31, 2012, 2011 and 2010 are summarized for all Registrant Subsidiaries in the following table:

	Average Interest Rate for Funds Borrowed from Utility Money Pool for Years Ended December 31,			Average Interest Rate for Funds Loaned to Utility Money Pool for Years Ended December 31,		
Company	**2012**	**2011**	**2010**	**2012**	**2011**	**2010**
APCo	0.47 %	0.42 %	0.26 %	0.47 %	0.32 %	- %
I&M	- %	0.39 %	0.43 %	0.46 %	0.38 %	0.24 %
OPCo	0.47 %	0.45 %	- %	0.47 %	0.35 %	0.22 %
PSO	- %	0.41 %	0.31 %	0.46 %	0.32 %	0.17 %
SWEPCo	0.53 %	0.40 %	0.19 %	0.45 %	0.33 %	0.27 %

Interest expense related to the Utility Money Pool is included in Interest Expense on each of the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries incurred interest expense for amounts borrowed from the Utility Money Pool as follows:

	Years Ended December 31,		
Company	**2012**	**2011**	**2010**
		(in thousands)	
APCo	$ 772	$ 198	$ 611
I&M	-	20	17
OPCo	555	12	16
PSO	11	85	102
SWEPCo	977	174	11

Interest income related to the Utility Money Pool is included in Interest Income on each of the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries earned interest income for amounts advanced to the Utility Money Pool as follows:

	Years Ended December 31,		
Company	**2012**	**2011**	**2010**
		(in thousands)	
APCo	$ 123	$ 313	$ 9
I&M	963	226	219
OPCo	1,038	820	708
PSO	435	250	19
SWEPCo	320	32	438

Short-term Debt

The Registrant Subsidiaries' outstanding short-term debt was as follows:

		December 31,			
		2012		**2011**	
Company	**Type of Debt**	**Outstanding Amount**	**Interest Rate (a)**	**Outstanding Amount**	**Interest Rate (a)**
		(in thousands)		**(in thousands)**	
SWEPCo	Line of Credit – Sabine	$ 2,603	1.82 %	$ 17,016	1.79 %

(a) Weighted average rate.

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, the Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for each Registrant Subsidiary's receivables. APCo does not have regulatory authority to sell its West Virginia accounts receivable. The costs of customer accounts receivable sold are reported in Other Operation expense on the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries manage and service their customer accounts receivable sold.

In 2012, AEP Credit renewed its receivables securitization agreement. The agreement provides a commitment of $700 million from bank conduits to finance receivables from AEP Credit. A commitment of $385 million expires in June 2013 and the remaining commitment of $315 million expires in June 2015.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement for each Registrant Subsidiary as of December 31, 2012 and 2011 was as follows:

Company	December 31, 2012	December 31, 2011
	(in thousands)	
APCo	$ 153,719	$ 121,605
I&M	123,447	121,597
OPCo	300,675	346,695
PSO	85,530	123,172
SWEPCo	132,449	140,440

The fees paid by the Registrant Subsidiaries to AEP Credit for customer accounts receivable sold were:

Company	Years Ended December 31, 2012	2011	2010
		(in thousands)	
APCo	$ 6,883	$ 9,612	$ 9,194
I&M	6,121	6,168	6,770
OPCo	20,312	18,851	20,630
PSO	7,054	6,363	5,406
SWEPCo	6,140	5,672	5,688

The Registrant Subsidiaries' proceeds on the sale of receivables to AEP Credit were:

Company	Years Ended December 31, 2012	2011	2010
		(in thousands)	
APCo	$ 1,353,920	$ 1,248,253	$ 1,418,487
I&M	1,344,260	1,323,068	1,283,955
OPCo	2,952,723	3,461,758	3,495,609
PSO	1,157,174	1,299,190	1,196,586
SWEPCo	1,481,925	1,495,397	1,402,525

13. RELATED PARTY TRANSACTIONS

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

Interconnection Agreement

APCo, I&M, KPCo, OPCo and AEPSC are parties to the Interconnection Agreement, which defines the sharing of costs and benefits associated with the respective 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.

In October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generating assets from its distribution and transmission operations. Additionally, the AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and to approve a new Power Coordination Agreement among APCo, I&M and KPCo. A decision from the FERC is expected in mid-2013. See "Corporate Separation and Termination of Interconnection Agreement" section of Note 2.

Power, gas and risk management activities are conducted by AEPSC and profits and losses are allocated under the SIA to members of the Interconnection Agreement, 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. Revenues and costs arising from third party sales are generally shared based on the amount of energy PSO or SWEPCo contributes that is sold to third parties.

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 to any Registrant Subsidiary is primarily sold to customers by such Registrant Subsidiary at rates approved (other than in Ohio) by the public utility commission in the jurisdiction of sale. In Ohio, such rates are based on a statutory formula as that jurisdiction transitions to the use of market rates for generation.

Under both the Interconnection Agreement and CSW Operating Agreement, power generated that is not needed to serve the native load of any Registrant Subsidiary is sold in the wholesale market by AEPSC on behalf of the generating subsidiary.

Affiliated Revenues and Purchases

The following tables show the revenues derived from sales under the Interconnection Agreement, direct sales to affiliates, net transmission agreement sales, natural gas contracts with AEPES and other revenues for the years ended December 31, 2012, 2011 and 2010:

Related Party Revenues	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Year Ended December 31, 2012					
Sales under Interconnection Agreement	$ 166,733	$ 265,923	$ 643,486	$ -	$ -
Direct Sales to East Affiliates	124,519	-	136,142	34	142
Direct Sales to West Affiliates	314	218	454	18,861	23,695
Direct Sales to AEPEP	-	-	-	-	(583)
Transmission Agreement and Transmission Coordination Agreement Sales	(1,289)	758	26,295	8	12,338
Natural Gas Contracts with AEPES	-	-	-	-	-
Other Revenues	27,922	1,509	40,917	3,700	1,849
Total Affiliated Revenues	$ 318,199	$ 268,408	$ 847,294	$ 22,603	$ 37,441

Related Party Revenues	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Year Ended December 31, 2011					
Sales under Interconnection Agreement	$ 186,788	$ 308,336	$ 823,703	$ -	$ -
Direct Sales to East Affiliates	126,737	-	115,120	124	3,535
Direct Sales to West Affiliates	1,492	908	1,936	10,624	43,714
Direct Sales to AEPEP	-	-	-	-	(637)
Transmission Agreement and Transmission Coordination Agreement Sales	2,348	9,379	3,375	111	8,962
Natural Gas Contracts with AEPES	154	92	196	3	4
Other Revenues	42,283	1,469	33,669	3,330	2,037
Total Affiliated Revenues	$ 359,802	$ 320,184	$ 977,999	$ 14,192	$ 57,615

Related Party Revenues	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Year Ended December 31, 2010					
Sales under Interconnection Agreement	$ 158,873	$ 327,992	$ 839,441	$ -	$ -
Direct Sales to East Affiliates	123,832	-	115,406	1,210	1,248
Direct Sales to West Affiliates	3,471	1,931	4,125	19,629	39,851
Direct Sales to AEPEP	-	-	-	-	(286)
Direct Sales to Transmission Companies	44	1,848	236	30	1
Natural Gas Contracts with AEPES	(2,171)	(1,087)	(2,330)	2	3
Other Revenues	32,158	267	34,407	2,657	11,053
Total Affiliated Revenues	$ 316,207	$ 330,951	$ 991,285	$ 23,528	$ 51,870

The following tables show the purchased power expenses incurred for purchases under the Interconnection Agreement and affiliates for the years ended December 31, 2012, 2011 and 2010:

Related Party Purchases	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Year Ended December 31, 2012					
Purchases under Interconnection Agreement	$ 661,185	$ 147,502	$ 174,240	$ -	$ -
Direct Purchases from East Affiliates	-	-	-	683	368
Direct Purchases from West Affiliates	53	36	75	23,695	18,861
Purchases from AEGCo	-	238,866	203,583	-	-
Gas Purchases from AEPES	-	-	2,808	-	-
Total Affiliated Purchases	$ 661,238	$ 386,404	$ 380,706	$ 24,378	$ 19,229

Related Party Purchases	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Year Ended December 31, 2011					
Purchases under Interconnection Agreement	$ 818,943	$ 124,598	$ 326,871	$ -	$ -
Direct Purchases from East Affiliates	-	-	-	6,378	1,184
Direct Purchases from West Affiliates	239	147	312	43,714	10,624
Purchases from AEGCo	-	228,739	185,741	-	-
Gas Purchases from AEPES	-	-	2,689	-	-
Total Affiliated Purchases	$ 819,182	$ 353,484	$ 515,613	$ 50,092	$ 11,808

Related Party Purchases	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Year Ended December 31, 2010					
Purchases under Interconnection Agreement	$ 916,791	$ 91,129	$ 268,964	$ -	$ -
Direct Purchases from East Affiliates	-	-	-	6,162	4,078
Direct Purchases from West Affiliates	825	466	996	39,851	19,629
Direct Purchases from AEGCo	-	235,740	113,801	-	-
Gas Purchases from AEPES	-	-	2,857	-	-
Total Affiliated Purchases	$ 917,616	$ 327,335	$ 386,618	$ 46,013	$ 23,707

The above summarized related party revenues and expenses are reported in Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates on the Registrant Subsidiaries' statements of income. Since the Registrant Subsidiaries are included in AEP's consolidated results, the above summarized related party transactions are eliminated in total in AEP's consolidated revenues and expenses.

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). This sharing was based upon each company's MLR until the FERC approved a new TA effective November 2010. The new TA will be phased-in for retail rates, added KGPCo and WPCo as parties to the agreement and changed the allocation method.

The following table shows the net charges recorded by the Registrant Subsidiaries for the years ended December 31, 2012 and 2011 related to the new TA:

Company	Years Ended December 31, 2012	2011
	(in thousands)	
APCo	$ 20,264	$ 4,608
I&M	5,689	1,538
OPCo	6,090	17,186

The charges shown above are recorded in Other Operation expenses on the statements of income.

The following table shows the net charges (credits) allocated among the Registrant Subsidiaries for the year ended December 31, 2010 related to the original TA:

Company	Year Ended December 31, 2010
	(in thousands)
APCo	$ (16,079)
I&M	(25,188)
OPCo	49,281

The net charges (credits) shown above are recorded in Other Operation expenses on the statements of income.

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

Under the TCA, the parties to the agreement delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The allocations have been governed by the FERC-approved OATT for the SPP.

The following table shows the net (revenues) expenses allocated among parties to the TCA pursuant to the SPP OATT protocols as described above for the years ended December 31, 2012, 2011 and 2010:

Company	Years Ended December 31, 2012	2011	2010
		(in thousands)	
PSO	$ 12,300	$ 9,000	$ 10,600
SWEPCo	(12,300)	(9,000)	(10,500)

The net (revenues) expenses shown above are recorded in Sales to AEP Affiliates on SWEPCo's statements of income and Other Operation expenses on PSO's statements of income.

Unit Power Agreements (UPA)

Lawrenceburg UPA between OPCo and AEGCo

In March 2007, OPCo and AEGCo entered into a ten-year UPA for the entire output from the Lawrenceburg Generating Station effective with AEGCo's purchase of the plant in May 2007. The UPA has an option for an additional two-year period. I&M operates the plant under an agreement with AEGCo. Under the UPA, OPCo pays AEGCo for the capacity, depreciation, fuel, operation and maintenance and tax expenses. These payments are due regardless of whether the plant is operating. The fuel and operation and maintenance payments are based on actual costs incurred. All expenses are trued up periodically.

UPA between AEGCo and I&M

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

UPA between AEGCo and KPCo

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

Cook Coal Terminal

Cook Coal Terminal, a division of OPCo, performs coal transloading services at cost for APCo and I&M. OPCo included revenues for these services in Other Revenues – Affiliated and expenses in Other Operation expenses on the statements of income. The coal transloading expenses in 2012, 2011 and 2010 were as follows:

Company	Years Ended December 31, 2012	2011	2010
		(in thousands)	
APCo	$ 942	$ 31	$ -
I&M	32,639	21,852	17,208

APCo and I&M recorded the cost of transloading services in Fuel on the balance sheets.

Cook Coal Terminal also performs railcar maintenance services at cost for APCo, I&M, PSO and SWEPCo. OPCo included revenues for these services in Sales to AEP Affiliates and expenses in Other Operation expenses on the statements of income. The railcar maintenance revenues in 2012, 2011 and 2010 were as follows:

Company	Years Ended December 31, 2012	2011	2010
		(in thousands)	
APCo	$ 88	$ 9	$ 7
I&M	3,343	3,012	1,870
PSO	281	542	522
SWEPCo	2,102	2,348	1,044

APCo, I&M, PSO and SWEPCo recorded the cost of the railcar maintenance services in Fuel on the balance sheets.

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, PSO and third parties. SWEPCo billed I&M $1.6 million and $2.9 million for railcar services provided in 2012 and 2011, respectively, and billed PSO $232 thousand and $287 thousand in 2012 and 2011, respectively. These billings for SWEPCo, and costs for I&M and PSO, are recorded in Fuel 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 in Other Revenues – Affiliated on the statements of income. The affiliated companies recorded these costs paid to I&M as fuel expenses or other operation expenses. The amounts of affiliated expenses were:

Company	Years Ended December 31, 2012	2011	2010
		(in thousands)	
AEGCo	$ 19,961	$ 15,460	$ 12,548
APCo	34,725	27,455	28,241
KPCo	74	122	133
OPCo	39,956	36,980	44,160
AEP River Operations LLC – (Nonutility Subsidiary of AEP)	20,917	25,356	20,729

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. The costs are recorded by I&M as Other Operation expenses. For the years ended December 31, 2012, 2011 and 2010, I&M recorded expenses of $24 million, $24 million and $28 million, respectively, for these activities.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers the cost of performing these services on the balance sheet, then transfers the cost to the affiliate for reimbursement. The AEP subsidiaries recorded these billings as capital or maintenance expenses depending on the nature of the services received. These billings are recoverable from customers. The following table provides the amounts billed by APCo to the following affiliates:

Company	Years Ended December 31, 2012	2011	2010
		(in thousands)	
AEGCo	$ 80	$ 102	$ 180
I&M	1,280	2,157	2,112
KPCo	277	298	368
OPCo	3,838	3,684	3,665
PSO	1,198	53	412
SWEPCo	145	946	560

Affiliate Coal Purchases

In 2008, OPCo entered into contracts to sell excess coal purchases to certain AEP subsidiaries through 2010. These purchases are reflected in Sales to AEP Affiliates on the statements of income. The following table shows the realized and unrealized amounts recorded for the year ended December 31, 2010:

Company	Year Ended December 31, 2010
	(in thousands)
APCo	$ 2,830
I&M	1,383
KPCo	837
PSO	796
SWEPCo	1,526

Affiliate Railcar Agreement

Certain AEP subsidiaries have an agreement providing for the use of each other's leased or owned railcars when available. The agreement specifies that the company using the railcar will be billed, at cost, by the company furnishing the railcar. The AEP subsidiaries recorded these costs or reimbursements as costs or reduction of costs, respectively, in Fuel on the balance sheets and such costs are recoverable from customers. The following tables show the net effect of the railcar agreement on the balance sheets:

December 31, 2012
Billing Company

Billed Company	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
APCo	$ -	$ 2	$ 1,960	$ -	$ 2
I&M	148	-	889	48	843
KPCo	98	-	41	-	-
OPCo	854	170	-	5	99
PSO	204	322	74	-	176
SWEPCo	543	1,468	321	21	-

December 31, 2011
Billing Company

Billed Company	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
APCo	$ -	$ -	$ 1,373	$ -	$ -
I&M	91	-	1,190	80	787
KPCo	289	-	355	-	-
OPCo	840	170	-	8	66
PSO	289	842	234	-	382
SWEPCo	12	2,662	605	91	-

OVEC

AEP, OPCo and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2012, AEP's and OPCo's ownership and investment in OVEC were as follows:

	December 31, 2012	
Company	Ownership	Investment
		(in thousands)
AEP	39.17 %	$ 3,978
OPCo	4.30 %	430
Total	43.47 %	$ 4,408

OVEC's owners, along with APCo and I&M, are members to an intercompany power agreement. Participants of this agreement are entitled to receive and obligated to pay for all OVEC generating capacity, approximately 2,200 MWs, in proportion to their respective power participation ratios. The aggregate power participation ratio of certain AEP utility subsidiaries, including APCo, I&M and OPCo, is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and provide a return on capital. In 2011, the intercompany power agreement was extended until June 2040.

AEP, OPCo and other nonaffiliated owners authorized environmental investments related to their ownership interests and OVEC's Board of Directors authorized capital expenditures totaling $1.4 billion in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at OVEC's two generating plants. As of December 31, 2012, OVEC completed financing of $1.4 billion required for these environmental projects through debt issuances. As of December 31, 2012, one plant was operating with new environmental controls and the other plant is scheduled to be operational with new environmental controls during the second quarter of 2013.

Purchased Power from OVEC

The amounts of power purchased by the Registrant Subsidiaries from OVEC for the years ended December 31, 2012, 2011 and 2010 were:

Company	Years Ended December 31, 2012	2011	2010
		(in thousands)	
APCo	$ 98,417	$ 114,311	$ 105,307
I&M	49,239	57,192	52,687
OPCo	125,013	145,207	133,776

The amounts shown above are recoverable from customers and are included in Purchased Electricity for Resale on the statements of income.

Purchases from OVEC under the Interconnection Agreement

In 2011, the parties to the Interconnection Agreement purchased power from OVEC to serve off-system sales and retail sales. These purchases are reported in Purchased Electricity for Resale on the statements of income. The following table shows the amounts recorded for the year ended December 31, 2011:

Company	Year Ended December 31, 2011
	(in thousands)
APCo	$ 21,110
I&M	12,942
OPCo	27,566

In January 2010, the parties to the Interconnection Agreement purchased power from OVEC to serve off-system sales and retail sales through June 2010. Purchases serving off-system sales are reported net as a reduction in Electric Generation, Transmission and Distribution revenues and purchases serving retail sales are reported in Purchased Electricity for Resale on the statements of income. The following table shows the amounts recorded for the year ended December 31, 2010:

	Year Ended December 31, 2010	
Company	Reported in Revenues	Reported in Expenses
	(in thousands)	
APCo	$ 6,631	$ 3,635
I&M	3,721	1,980
OPCo	7,937	4,231

Sales and Purchases of Property

Certain AEP subsidiaries had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions. The following tables show the sales and purchases, that were recorded at net book value, for the years ended December 31, 2012, 2011 and 2010:

Sales

Company	Years Ended December 31, 2012	2011	2010
		(in thousands)	
APCo	$ 6,643	$ 3,978	$ 2,004
I&M	3,296	441	1,842
OPCo	4,163	12,113	8,919
PSO	1,782	442	2,156
SWEPCo	1,731	650	5,233

Purchases

Company	Years Ended December 31, 2012	2011	2010
		(in thousands)	
APCo	$ 2,522	$ 2,312	$ 4,732
I&M	285	3,678	4,117
OPCo	10,608	3,045	1,652
PSO	1,867	475	5,146
SWEPCo	7,266	2,993	2,612

The amounts above are recorded in Property, Plant and Equipment on the balance sheets.

Global Borrowing Notes

As of December 31, 2012 and 2011, AEP has an intercompany note in place with OPCo. The debt is reflected in Long-term Debt – Affiliated on OPCo's balance sheets. OPCo accrues interest for its share of the global borrowing and remits the interest to AEP. The accrued interest is reflected in Accrued Interest on OPCo's balance sheets.

Intercompany Billings

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

14. VARIABLE INTEREST ENTITIES

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether they are the primary beneficiary of a VIE, management considers for each Registrant Subsidiary factors such as equity at risk, the amount of the VIE's variability the Registrant Subsidiary absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. Management believes that significant assumptions and judgments were applied consistently. In addition, the Registrant Subsidiaries have not provided financial or other support to any VIE that was not previously contractually required.

SWEPCo is the primary beneficiary of Sabine. I&M is the primary beneficiary of DCC Fuel. APCo, I&M, OPCo, PSO and SWEPCo each hold a significant variable interest in AEPSC. I&M and OPCo each hold a significant variable interest in AEGCo. SWEPCo holds a significant variable interest in DHLC.

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the years ended December 31, 2012, 2011 and 2010 were $147 million, $128 million and $133 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on SWEPCo's balance sheets.

The balances below represent the assets and liabilities of Sabine that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
VARIABLE INTEREST ENTITIES
December 31, 2012 and 2011
(in thousands)

	Sabine	
	2012	**2011**
ASSETS		
Current Assets	$ 56,535	$ 48,044
Net Property, Plant and Equipment	170,436	153,715
Other Noncurrent Assets	55,076	42,574
Total Assets	$ 282,047	$ 244,333
LIABILITIES AND EQUITY		
Current Liabilities	$ 31,446	$ 67,779
Noncurrent Liabilities	250,340	176,163
Equity	261	391
Total Liabilities and Equity	$ 282,047	$ 244,333

I&M has nuclear fuel lease agreements with DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, DCC Fuel IV LLC and DCC Fuel V LLC (collectively DCC Fuel). DCC Fuel was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the years ended December 31, 2012, 2011 and 2010 were $127 million, $85 million and $59 million, respectively. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the respective lease terms, which do not exceed 54 months. Based on I&M's control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. See the table below for the classification of DCC Fuel's assets and liabilities on I&M's balance sheets.

The balances below represent the assets and liabilities of DCC Fuel that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
VARIABLE INTEREST ENTITIES
December 31, 2012 and 2011
(in thousands)

	DCC Fuel	
ASSETS	**2012**	**2011**
Current Assets	$ 132,886	$ 118,144
Net Property, Plant and Equipment	176,065	188,375
Other Noncurrent Assets	92,473	117,772
Total Assets	$ 401,424	$ 424,291
LIABILITIES AND EQUITY		
Current Liabilities	$ 120,873	$ 102,946
Noncurrent Liabilities	280,551	321,345
Equity	-	-
Total Liabilities and Equity	$ 401,424	$ 424,291

DHLC is a mining operator which sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and voting rights equally. Each entity guarantees 50% of DHLC's debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. SWEPCo's total billings from DHLC for the years ended December 31, 2012, 2011 and 2010 were $77 million, $62 million and $56 million, respectively. SWEPCo is not required to consolidate DHLC as it is not the primary beneficiary, although SWEPCo holds a significant variable interest in DHLC. SWEPCo's equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheets.

SWEPCo's investment in DHLC was:

	December 31,			
	2012		2011	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in thousands)			
Capital Contribution from SWEPCo	$ 7,643	$ 7,643	$ 7,643	$ 7,643
Retained Earnings	946	946	1,120	1,120
SWEPCo's Guarantee of Debt	-	49,564	-	52,310
Total Investment in DHLC	$ 8,589	$ 58,153	$ 8,763	$ 61,073

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. 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. AEP subsidiaries have not provided financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP.

Total AEPSC billings to the Registrant Subsidiaries were as follows:

Company	Years Ended December 31, 2012	2011	2010
		(in thousands)	
APCo	$ 195,176	$ 195,787	$ 238,367
I&M	127,232	126,505	139,920
OPCo	277,232	279,652	332,431
PSO	89,199	84,028	102,116
SWEPCo	136,642	130,148	147,928

The carrying amount and classification of variable interest in AEPSC's accounts payable are as follows:

	December 31, 2012		2011	
Company	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
		(in thousands)		
APCo	$ 29,819	$ 29,819	$ 20,812	$ 20,812
I&M	17,911	17,911	13,741	13,741
OPCo	39,323	39,323	29,823	29,823
PSO	13,381	13,381	9,280	9,280
SWEPCo	19,669	19,669	14,699	14,699

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant Unit 1, leases a 50% interest in Rockport Plant Unit 2 and owns 100% of the Lawrenceburg Generating Station. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEGCo leases the Lawrenceburg Generating Station to OPCo. AEP guarantees all the debt obligations of AEGCo. I&M and OPCo are considered to have a significant interest in AEGCo due to these transactions. I&M and OPCo are exposed to losses to the extent they cannot recover the costs of AEGCo through their normal business operations. In the event AEGCo would require financing or other support outside the billings to I&M, OPCo and KPCo, this financing would be provided by AEP. For additional information regarding AEGCo's lease, see "Rockport Lease" section of Note 11.

Total billings from AEGCo were as follows:

Company	Years Ended December 31, 2012	2011	2010
		(in thousands)	
I&M	$ 238,865	$ 228,739	$ 235,741
OPCo	203,582	185,741	113,801

The carrying amount and classification of variable interest in AEGCo's accounts payable are as follows:

	December 31, 2012		2011	
Company	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
		(in thousands)		
I&M	$ 25,498	$ 25,498	$ 25,731	$ 25,731
OPCo	16,302	16,302	22,139	22,139

15. PROPERTY, PLANT AND EQUIPMENT

Depreciation, Depletion and Amortization

The Registrant Subsidiaries provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following tables provide annual property information for the Registrant Subsidiaries:

APCo

2012	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 5,632,665	$ 1,928,562	3.0 %	40 - 121	$ -	$ -	NA	NA
Transmission	2,042,144	468,633	1.6 %	25 - 87	-	-	NA	NA
Distribution	2,991,898	641,504	3.4 %	13 - 57	-	-	NA	NA
CWIP	266,247	(19,379)	NM	NM	-	-	NA	NA
Other	340,027	164,932	6.8 %	24 - 55	33,300	12,387	NM	NM
Total	$ 11,272,981	$ 3,184,252			$ 33,300	$ 12,387		

2011	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 5,194,967	$ 1,783,154	2.6 %	40 - 121	$ -	$ -	NA	NA
Transmission	1,943,969	457,235	1.6 %	25 - 87	-	-	NA	NA
Distribution	2,845,405	595,122	3.2 %	11 - 52	-	-	NA	NA
CWIP	565,841	(9,918)	NM	NM	-	-	NA	NA
Other	323,630	155,688	6.6 %	24 - 55	33,696	12,735	NM	NM
Total	$ 10,873,812	$ 2,981,281			$ 33,696	$ 12,735		

2010	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Generation	2.4 %	40 - 121	NA	NA
Transmission	1.6 %	25 - 87	NA	NA
Distribution	3.2 %	11 - 52	NA	NA
CWIP	NM	NM	NA	NA
Other	7.8 %	24 - 55	NM	NM

NA Not applicable.
NM Not meaningful.

I&M

2012	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 4,062,733	$ 2,130,136	1.7 %	59 - 132	$ -	$ -	NA	NA
Transmission	1,278,236	411,825	1.5 %	46 - 75	-	-	NA	NA
Distribution	1,553,358	373,342	2.5 %	14 - 70	-	-	NA	NA
CWIP	341,063	65,449	NM	NM	-	-	NA	NA
Other	573,836	141,291	9.6 %	14 - 40	151,477	110,092	NM	NM
Total	$ 7,809,226	$ 3,122,043			$ 151,477	$ 110,092		

2011	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 3,932,472	$ 2,078,651	1.6 %	59 - 132	$ -	$ -	NA	NA
Transmission	1,224,786	414,941	1.4 %	46 - 75	-	-	NA	NA
Distribution	1,481,608	374,137	2.4 %	14 - 70	-	-	NA	NA
CWIP	236,096	60,665	NM	NM	-	-	NA	NA
Other	559,698	143,312	7.4 %	NM	149,860	108,214	NM	NM
Total	$ 7,434,660	$ 3,071,706			$ 149,860	$ 108,214		

2010	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciable Rate	Depreciable Life Ranges	Annual Composite Depreciable Rate	Depreciable Life Ranges
		(in years)		(in years)
Generation	1.6 %	59 - 132	NA	NA
Transmission	1.4 %	46 - 75	NA	NA
Distribution	2.5 %	14 - 70	NA	NA
CWIP	NM	NM	NA	NA
Other	11.7 %	NM	NM	NM

NA Not applicable.
NM Not meaningful.

OPCo

2012	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ -	$ -	NA	NA	$ 8,673,296	$ 3,200,427	3.0 %	35 - 66
Transmission	2,013,737	809,199	2.3 %	39 - 60	-	-	NA	NA
Distribution	3,722,745	1,011,324	2.7 %	12 - 60	-	-	NA	NA
CWIP	147,408	(21,198)	NM	NM	207,089	1,350	NM	NM
Other	427,412	224,153	7.3 %	25 - 50	143,742	17,550	NM	NM
Total	$ 6,311,302	$ 2,023,478			$ 9,024,127	$ 3,219,327		

2011	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ -	$ -	NA	NA	$ 9,502,614	$ 3,596,589	3.2 %	35 - 66
Transmission	1,948,329	763,664	2.3 %	27 - 70	-	-	NA	NA
Distribution	3,545,574	1,146,202	3.7 %	12 - 56	-	-	NA	NA
CWIP	183,096	(3,371)	NM	NM	171,369	1,152	NM	NM
Other	407,044	222,368	8.7 %	NM	139,598	15,957	NM	NM
Total	$ 6,084,043	$ 2,128,863			$ 9,813,581	$ 3,613,698		

2010	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Generation	NA	NA	3.3 %	35 - 70
Transmission	2.3 %	27 - 70	NA	NA
Distribution	3.7 %	12 - 56	NA	NA
CWIP	NM	NM	NM	NM
Other	9.2 %	NM	NM	NM

NA Not applicable.
NM Not meaningful.

PSO

2012	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 1,346,530	$ 654,989	1.7 %	35 - 70	$ -	$ -	NA	NA
Transmission	706,917	176,187	1.9 %	40 - 75	-	-	NA	NA
Distribution	1,859,557	345,207	2.4 %	30 - 65	-	-	NA	NA
CWIP	95,170	(9,281)	NM	NM	-	-	NA	NA
Other	205,373	111,837	6.6 %	5 - 40	5,176	2	NM	NM
Total	$ 4,213,547	$ 1,278,939			$ 5,176	$ 2		

2011	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 1,317,948	$ 652,526	1.8 %	9 - 70	$ -	$ -	NA	NA
Transmission	692,644	167,827	1.9 %	40 - 75	-	-	NA	NA
Distribution	1,762,110	329,041	2.4 %	30 - 65	-	-	NA	NA
CWIP	70,371	(5,413)	NM	NM	-	-	NA	NA
Other	209,467	122,838	8.3 %	5 - 35	5,159	(3)	NM	NM
Total	$ 4,052,540	$ 1,266,819			$ 5,159	$ (3)		

2010	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Generation	1.8 %	9 - 70	NA	NA
Transmission	1.9 %	40 - 75	NA	NA
Distribution	2.4 %	27 - 65	NA	NA
CWIP	NM	NM	NA	NA
Other	8.3 %	5 - 35	NM	NM

NA Not applicable.
NM Not meaningful.

SWEPCo

2012	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 3,888,230	$ 1,092,566	2.2 %	35 - 65	$ -	$ -	NA	NA
Transmission	1,115,795	301,159	2.3 %	50 - 70	-	-	NA	NA
Distribution	1,758,988	556,904	2.6 %	25 - 65	-	-	NA	NA
CWIP	99,783 (a)	(8,294)	NM	NM	-	-	NA	NA
Other	397,643	225,254	6.6 %	7 - 47	290,611	116,669	NM	NM
Total	$ 7,260,439	$ 2,167,589			$ 290,611	$ 116,669		

2011	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 2,326,102	$ 1,060,825	2.1 %	35 - 68	$ -	$ -	NA	NA
Transmission	988,534	285,785	2.3 %	50 - 70	-	-	NA	NA
Distribution	1,675,764	535,565	2.6 %	25 - 65	-	-	NA	NA
CWIP	1,419,216 (a)	(3,527)	NM	NM	24,353	-	NM	NM
Other	400,492	229,695	6.9 %	7 - 47	236,527	103,569	NM	NM
Total	$ 6,810,108	$ 2,108,343			$ 260,880	$ 103,569		

2010	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Generation	1.9 %	35 - 68	NA	NA
Transmission	2.4 %	50 - 70	NA	NA
Distribution	2.7 %	25 - 65	NA	NA
CWIP	NM	NM	NM	NM
Other	7.7 %	7 - 47	NM	NM

(a) Includes CWIP related to SWEPCo's Arkansas jurisdictional share of the Turk Plant.
NA Not applicable.
NM Not meaningful.

SWEPCo provides for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. SWEPCo uses either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. SWEPCo includes these costs in fuel expense.

For rate-regulated operations, the composite depreciation rate generally includes a component for nonasset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

Asset Retirement Obligations (ARO)

The Registrant Subsidiaries record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for the retirement of certain ash disposal facilities, closure and monitoring of underground carbon storage facilities at Mountaineer Plant and coal mining facilities as well as asbestos removal. I&M records ARO for the decommissioning of the Cook Plant. The Registrant Subsidiaries have 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 the Registrant Subsidiaries plan to use their facilities indefinitely. The retirement obligation would only be recognized if and when the Registrant Subsidiaries abandon or cease the use of specific easements, which is not expected.

As of December 31, 2012 and 2011, I&M's ARO liability for nuclear decommissioning of the Cook Plant was $1.2 billion and $979 million, respectively. These liabilities are reflected in Asset Retirement Obligations on I&M's balance sheets. As of December 31, 2012 and 2011, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $1.4 billion and $1.3 billion, respectively. These assets are included in Spent Nuclear Fuel and Decommissioning Trusts on I&M's balance sheets.

The following is a reconciliation of the 2012 and 2011 aggregate carrying amounts of ARO by Registrant Subsidiary:

Company	ARO as of December 31, 2011	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of December 31, 2012
			(in thousands)			
APCo (a)(d)	$ 112,767	$ 7,264	$ -	$ (8,921)	$ 4,058	$ 115,168
I&M (a)(b)(d)	1,013,122	53,848	-	(806)	126,149	1,192,313
OPCo (a)(d)	241,828	15,113	-	(8,294)	21,293	269,940
PSO (a)(d)	19,623	1,572	84	(949)	1,669	21,999
SWEPCo (a)(c)(d)(e)	67,183	5,511	17,380	(3,831)	(8,226)	78,017

Company	ARO as of December 31, 2010	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of December 31, 2011
			(in thousands)			
APCo (a)(d)	$ 141,924	$ 9,534	$ 3	$ (3,600)	$ (35,094)	$ 112,767
I&M (a)(b)(d)	963,029	51,308	-	(1,370)	155	1,013,122
OPCo (a)(d)	189,271	13,499	165	(4,872)	43,765	241,828
PSO (a)(d)	21,557	1,708	-	(414)	(3,228)	19,623
SWEPCo (a)(c)(d)(e)	59,382	4,114	7,063	(14,947)	11,571	67,183

(a) Includes ARO related to ash disposal facilities.
(b) Includes ARO related to nuclear decommissioning costs for the Cook Plant of $1.2 billion and $979 million as of December 31, 2012 and 2011, respectively.
(c) Includes ARO related to Sabine and DHLC.
(d) Includes ARO related to asbestos removal.
(e) The current portion of SWEPCo's ARO totaling $1.5 million as of December 31, 2011 is included in Other Current Liabilities on SWEPCo's balance sheets.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

The Registrant Subsidiaries' amounts of allowance for equity funds used during construction are summarized in the following table:

	Years Ended December 31,		
Company	**2012**	**2011**	**2010**
		(in thousands)	
APCo	$ 1,684	$ 9,212	$ 2,967
I&M	9,724	15,395	15,678
OPCo	3,492	5,549	5,949
PSO	2,007	1,317	804
SWEPCo	57,054	48,731	45,646

The Registrant Subsidiaries' amounts of allowance for borrowed funds used during construction, including capitalized interest, are summarized in the following table:

	Years Ended December 31,		
Company	**2012**	**2011**	**2010**
		(in thousands)	
APCo	$ 1,347	$ 6,257	$ 2,251
I&M	4,717	7,838	8,500
OPCo	9,046	2,350	3,786
PSO	1,098	822	572
SWEPCo	48,499	40,904	33,668

Jointly-owned Electric Facilities

The Registrant Subsidiaries have electric facilities that are jointly-owned with affiliated and nonaffiliated companies. 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. Each Registrant Subsidiary'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 Property, Plant and Equipment as follows:

			Company's Share as of December 31, 2012		
Company	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
APCo					
John E. Amos Generating Station (Unit No. 3) (a)	Coal	33.33 %	$ 563,470	$ 14,188	$ 108,441
I&M					
Rockport Generating Plant (Unit No. 1) (b)	Coal	50.0 %	$ 762,737	$ 55,420	$ 456,436
OPCo					
John E. Amos Generating Station (Unit No. 3) (a)	Coal	66.67 %	$ 995,005	$ 14,093	$ 213,163
W.C. Beckjord Generating Station 2 (Unit No. 6) (c)	Coal	12.5 %	-	-	-
Conesville Generating Station (Unit No. 4) (d)	Coal	43.5 %	310,342	26,067	58,677
J.M. Stuart Generating Station (e)	Coal	26.0 %	541,719	11,151	180,687
Wm. H. Zimmer Generating Station (c)	Coal	25.4 %	807,431	1,817	387,209
Transmission	NA	(f)	69,148	4,101	50,516
Total			$ 2,723,645	$ 57,229	$ 890,252
PSO					
Oklaunion Generating Station (Unit No. 1) (g)	Coal	15.6 %	$ 93,218	$ 939	$ 57,060
SWEPCo					
Dolet Hills Generating Station (Unit No. 1) (h)	Lignite	40.2 %	$ 262,649	$ 7,523	$ 195,336
Flint Creek Generating Station (Unit No. 1) (i)	Coal	50.0 %	121,052	14,272	64,348
Pirkey Generating Station (Unit No. 1) (i)	Lignite	85.9 %	513,833	16,029	371,015
Turk Generating Plant (j)	Coal	73.33 %	1,612,618	(2,669)	59
Total			$ 2,510,152	$ 35,155	$ 630,758

			Company's Share as of December 31, 2011		
Company	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
APCo					
John E. Amos Generating Station (Unit No. 3) (a)	Coal	33.33 %	$ 554,555	$ 16,987	$ 93,404
I&M					
Rockport Generating Plant (Unit No. 1) (b)	Coal	50.0 %	$ 759,033	$ 19,357	$ 443,857
OPCo					
John E. Amos Generating Station (Unit No. 3) (a)	Coal	66.67 %	$ 988,510	$ 15,344	$ 188,820
W.C. Beckjord Generating Station (Unit No. 6) (c)	Coal	12.5 %	19,131	108	8,476
Conesville Generating Station (Unit No. 4) (d)	Coal	43.5 %	309,771	11,633	53,980
J.M. Stuart Generating Station (e)	Coal	26.0 %	528,271	13,292	171,830
Wm. H. Zimmer Generating Station (c)	Coal	25.4 %	771,158	19,949	376,585
Transmission	NA	(f)	63,115	5,805	49,487
Total			$ 2,679,956	$ 66,131	$ 849,178
PSO					
Oklaunion Generating Station (Unit No. 1) (g)	Coal	15.6 %	$ 92,805	$ 446	$ 56,539
SWEPCo					
Dolet Hills Generating Station (Unit No. 1) (h)	Lignite	40.2 %	$ 264,487	$ 465	$ 193,565
Flint Creek Generating Station (Unit No. 1) (i)	Coal	50.0 %	118,163	6,532	62,988
Pirkey Generating Station (Unit No. 1) (i)	Lignite	85.9 %	512,557	674	361,667
Turk Generating Plant (j)	Coal	73.33 %	-	1,326,013	-
Total			$ 895,207	$ 1,333,684	$ 618,220

(a) Operated by APCo.
(b) Operated by I&M.
(c) Operated by Duke Energy Corporation, a nonaffiliated company. AEP's portion of this unit was impaired in the fourth quarter of 2012. See "Impairments" section of Note 5.
(d) Operated by OPCo.
(e) Operated by The Dayton Power & Light Company, a nonaffiliated company.
(f) Varying percentages of ownership.
(g) Operated by PSO and also jointly-owned (54.7%) by TNC.
(h) Operated by CLECO, a nonaffiliated company.
(i) Operated by SWEPCo.
(j) Turk Generating Plant was placed in service in December 2012. SWEPCo jointly owns the plant with Arkansas Electric Cooperative Corporation (11.67%), East Texas Electric Cooperative (8.33%) and Oklahoma Municipal Power Authority (6.67%). Through December 2012, construction costs totaling $457 million have been billed to the other owners.
NA Not applicable.

16. COST REDUCTION PROGRAMS

2012 Sustainable Cost Reductions

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

The Registrant Subsidiaries recorded a charge to expense during 2012 related to the sustainable cost reductions initiative.

	Expense Allocation from AEPSC	Incurred for Registrant Subsidiaries	Settled	Remaining Balance as of December 31, 2012
		(in thousands)		
APCo	$ 6,452	$ 2,020	$ (7,151)	$ 1,321
I&M	4,167	1,511	(4,321)	1,357
OPCo	9,225	4,273	(10,048)	3,450
PSO	3,020	655	(3,023)	652
SWEPCo	4,199	1,510	(5,082)	627

These expenses relate primarily to severance benefits. They are included primarily in Other Operation expense on the statement of income and Other Current Liabilities on the balance sheet.

2010 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. Many of these eliminated positions resulted from employees that elected retirement through voluntary severance. Most of the affected employees terminated employment as of May 31, 2010. The severance program provided two weeks of base pay for every year of service along with other severance benefits.

The Registrant Subsidiaries recorded a charge to Other Operation expense during 2010 primarily related to severance benefits as the result of headcount reduction initiatives. The total amount incurred in 2010 by Registrant Subsidiary was as follows:

Company	Total Cost Incurred
	(in thousands)
APCo	$ 56,925
I&M	45,036
OPCo	85,400
PSO	24,005
SWEPCo	29,662

For the Registrant Subsidiaries who had cost reduction activity remaining as of December 31, 2011, the activity for 2012 is described in the following table:

Company	Balance as of December 31, 2011	Settled	Adjustments	Balance as of December 31, 2012
		(in thousands)		
APCo	$ 92	$ -	$ (92)	$ -
OPCo	138	(138)	-	-

17. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In management's opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. The unaudited quarterly financial information for each Registrant Subsidiary is as follows:

Quarterly Periods Ended:	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
March 31, 2012					
Total Revenues	$ 805,476	$ 546,207	$ 1,237,223	$ 300,531	$ 348,986
Operating Income	169,190	76,325	269,619	33,490	55,368
Net Income	75,311	39,221	150,830	12,648	36,395
June 30, 2012					
Total Revenues	$ 716,461	$ 510,876	$ 1,113,750	$ 317,311	$ 390,946
Operating Income	143,426	64,803	210,004	69,299	72,976
Net Income	62,332	29,810	101,423	35,211	54,902
September 30, 2012					
Total Revenues	$ 864,198	$ 598,204	$ 1,359,816	$ 372,872	$ 485,169
Operating Income	142,722	80,486	279,109	106,196	120,008
Net Income	63,191	39,254	151,510	58,103	89,218
December 31, 2012					
Total Revenues	$ 890,796	$ 544,824	$ 1,217,407	$ 242,224	$ 352,733
Operating Income (Loss)	142,122	26,080	(81,785)(a)	21,965	27,544
Net Income (Loss)	56,669	10,172	(60,229)(a)	8,179	21,998

Quarterly Periods Ended:	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
March 31, 2011					
Total Revenues	$ 831,820	$ 560,492	$ 1,394,190	$ 288,003	$ 362,955
Operating Income	116,061 (b)	95,994	299,396	38,881	54,528
Net Income	38,980 (b)	45,427	165,970	15,389	29,827
June 30, 2011					
Total Revenues	$ 751,445	$ 521,478	$ 1,285,558	$ 328,588	$ 399,534
Operating Income	88,567	64,351	261,534	64,185	80,054
Net Income	31,627	31,386	142,194	31,560	51,071
September 30, 2011					
Total Revenues	$ 858,336	$ 611,232	$ 1,540,231	$ 457,586	$ 534,982
Operating Income	122,716	100,352	210,453 (c)	103,006	128,406
Net Income	52,804	51,702	128,339 (c)	57,349	87,795
December 31, 2011					
Total Revenues	$ 763,624	$ 521,568	$ 1,211,132	$ 289,211	$ 356,355
Operating Income (Loss)	102,236 (d)	20,959	63,321 (e)	34,939	(12,731) (f)
Net Income (Loss)	39,347 (d)	21,159	28,490 (e)	20,330	(3,567) (f)

(a) Includes pretax impairments for certain Ohio generation plants (see Note 5).

(b) Includes a $41 million increase due to the pretax write-off of a portion of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the WVPSC. This increase was partially offset by the $32 million decrease due to the deferral of 2010 costs related to storms and cost reduction initiatives as allowed by the WVPSC.

(c) Includes pretax plant impairments for the Sporn Unit 5 shutdown and FGD project at Muskingum River Unit 5 (see Note 5). Also includes a $43 million provision for refund of POLR charges.

(d) Includes a $31 million pretax write-off related to the disallowance of certain Virginia environmental costs incurred in 2009 and 2010 as a result of APCo's November 2011 Virginia SCC order. Includes a $27 million increase due to a favorable Asset Retirement Obligation adjustment related to the early closure and previous write-off of the Mountaineer Carbon Capture and Storage Product Validation Facility.

(e) Includes provisions related to the FAC, the 2010 SEET and the obligation to contribute to Partnership with Ohio and Ohio Growth Fund.

(f) Includes a pretax plant impairment for the Turk Plant (see Note 5).

COMBINED MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the Registrant Subsidiaries' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and net income and is meant to be read with (a) Management's Narrative Discussion and Analysis of Results of Operations, (b) financial statements, (c) footnotes and (d) the schedules of each individual registrant.

EXECUTIVE OVERVIEW

Sustainable Cost Reductions

In April 2012, a process was initiated to identify strategic repositioning opportunities and efficiencies that will result in sustainable cost savings. Management selected a consulting firm to conduct an organizational and process optimization evaluation and a second firm to evaluate the Registrant Subsidiaries' current employee benefit programs. A charge was recorded to expense of $47 million ($30 million, net of tax) in 2012 related primarily to severance benefits. Management expects to complete the final phase of the sustainable cost reduction program by the end of the first quarter of 2013. Going forward, management anticipates that this program provides a behavioral foundation upon which additional process improvement projects will be implemented as a regular business practice. At this time, management is unable to estimate the total amount to be incurred in future periods related to this initiative or to quantify the effects on future earnings, cash flows and financial condition.

Customer Demand

In comparison to 2011, cooling degree days in 2012 were down 6% in AEP's western region and up 4% in AEP's eastern region. Heating degree days in 2012 were down in AEP's western and eastern regions by 36% and 15%, respectively. Weather-normalized retail sales across the AEP System were down 0.7% compared to 2011. OPCo's weather-normalized industrial sales declined 4.4% partially due to Ormet, a large aluminum company that lowered their production in the third quarter of 2012 by one-third. In February 2013, Ormet filed Chapter 11 bankruptcy proceedings in the state of Delaware.

In 2013, management anticipates slight increases in retail sales in AEP's eastern region related to shale gas development and processing and in AEP's western region related to oil and gas extraction. Management also anticipates decreases in OPCo's industrial demand related to Ormet's lower production levels discussed above.

LITIGATION

Potential Uninsured Losses

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 a nuclear incident at the Cook Plant. Future losses or liabilities, which are not completely insured, unless recovered from customers, could reduce future net income and cash flows and impact financial condition.

ENVIRONMENTAL ISSUES

The Registrant Subsidiaries are implementing a substantial capital investment program and incurring additional operational costs to comply with new environmental control requirements. The Registrant Subsidiaries will need to make additional investments and operational changes in response to existing and anticipated requirements such as CAA requirements to reduce emissions of SO_2, NO_x, PM and hazardous air pollutants (HAPs) from fossil fuel-fired power plants, new proposals governing the beneficial use and disposal of coal combustion products and proposed clean water rules.

The Registrant Subsidiaries are engaged in litigation about environmental issues, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of SNF and future decommissioning of I&M's nuclear units. AEP, various industry groups, affected states and other parties have challenged some of the Federal EPA requirements in court. Management is also engaged in the development of possible future requirements including the items discussed below and reductions of CO_2 emissions to address concerns about global climate change. Management believes that further analysis and better coordination of these future environmental requirements would facilitate planning and lower overall compliance costs while achieving the same environmental goals.

Management will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. Recovery in Ohio will be dependent upon prevailing market conditions. If the Registrant Subsidiaries are unable to recover the costs of environmental compliance, it would reduce future net income and cash flows and impact financial condition.

Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed in the next several sections will have a material impact on the generating units in the AEP System. Management continues to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of December 31, 2012, the AEP System had a total generating capacity of nearly 37,600 MWs, of which over 23,700 MWs are coal-fired. Management continues to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on the coal-fired generating facilities. For the Registrant Subsidiaries, management's current ranges of estimates of environmental investments to comply with these proposed requirements are listed below:

	2012 to 2020 Estimated Environmental Investment	
Company	**Low**	**High**
	(in millions)	
APCo	$ 330	$ 440
I&M	510	610
OPCo	840	1,080
PSO	310	380
SWEPCo	1,430	1,750

For APCo, I&M and OPCo, the projected environmental investments above include the conversions of 470 MWs, 500 MWs and 585 MWs of coal generation to natural gas generation, respectively. If natural gas conversion is not completed, these units could be retired sooner than planned.

The preceding discussion of environmental investments and plans for future years reflects the ownership of plants as of December 31, 2012. The AEP East Companies have filed with the FERC to terminate the Interconnection Agreement and for OPCo to transfer facilities to APCo, KPCo and AEPGenCo. Management expects the transfers will be effective December 31, 2013.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in the final rules. The cost estimates for each Registrant Subsidiary will also change based on: (a) the states' implementation of these regulatory programs, including the potential for state implementation plans or federal implementation plans that impose standards more stringent than the proposed rules, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on the units, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity and (g) other factors.

Subject to the factors listed above and based upon management's continuing evaluation, management has given notice to the applicable RTOs of intent to retire the following plants or units of plants before or during 2016:

Company	Plant Name and Unit	Generating Capacity (in MWs)
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
APCo/OPCo	Philip Sporn Plant, Units 1-4	600
I&M	Tanners Creek Plant, Units 1-3	495
OPCo	Kammer Plant	630
OPCo	Muskingum River Plant, Units 1-4	840
OPCo	Picway Plant	100
SWEPCo	Welsh Plant, Unit 2	528

Duke Energy Corporation, the operator of W. C. Beckjord Generating Station, has announced its intent to close the facility in 2015. OPCo owns 12.5% (53 MWs) of one unit at that station.

In September 2012, based upon an agreement in principle with the Federal EPA, the State of Oklahoma and other parties, PSO filed an environmental compliance plan with the OCC to retire Units 3 and 4 of the Northeastern Station, a total of 930 MWs, in 2026 and 2016, respectively. See "Oklahoma Environmental Compliance Plan" and "Regional Haze" sections below.

In December 2012, OPCo retired its 165 MW Conesville Plant, Unit 3.

A decline in natural gas prices, pending environmental rules and the proposed termination of the Interconnection Agreement had an adverse impact on the recoverability of the net book values of certain coal-fired units. In 2012, OPCo recorded a $287 million pretax impairment charge for the net book value of certain plants totaling 1,870 MWs in the table above and Beckjord and Conesville plants discussed above. See "Impairments" section of Note 5.

Plans for and the timing of conversion of some of the coal units to natural gas, installing emission control equipment on other units and closure of existing units will be impacted by changes in emission requirements and demand for power. To the extent existing generation assets and the cost of new equipment and converted facilities are not recoverable, it could materially reduce future net income and cash flows.

Modification of the NSR Litigation Consent Decree

In 2007, the U.S. District Court for the Southern District of Ohio approved a consent decree between AEP subsidiaries in the eastern area of the AEP System and the Department of Justice, the Federal EPA, eight northeastern states and other interested parties to settle all claims that the AEP subsidiaries violated the NSR provisions of the CAA when they undertook various equipment repair and replacement projects over a period of nearly 20 years. The consent decree's terms include installation of environmental control equipment on certain generating units, a declining cap on SO_2 and NO_x emissions from the AEP System and various mitigation projects.

The consent decree requires certain types of control equipment to be installed at Muskingum River Plant, Unit 5 and Big Sandy Plant, Unit 2 in 2015 and the two units of the Rockport Plant in 2017 and 2019. In February 2013, an agreement to modify the consent decree was reached and filed with the court. The terms of the modification include more options for the affected units (including alternative control technologies, re-fueling and/or retirement), more stringent SO_2 emission caps for the AEP System and additional mitigation measures. The Federal EPA will seek public comments on the modification prior to its entry by the court. Under the terms of the modification, the units of Rockport Plant will be equipped with dry sorbent injection systems in 2015 and have options to retrofit additional SO_2 controls, refuel, repower or retire in 2025 and 2028. Muskingum River Plant, Unit 5 will have options to cease burning coal and retire in 2015 or cease burning coal in 2015 and complete a refueling project no later than June 2017. I&M will secure an additional 200 MWs of renewable power resources by December 2014 and provide $8.5 million for additional mitigation projects.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements.

The Federal EPA issued the Clean Air Interstate Rule (CAIR) in 2005 requiring specific reductions in SO_2 and NO_x emissions from power plants. In 2008, the District of Columbia Circuit Court of Appeals issued a decision remanding CAIR to the Federal EPA. The Federal EPA issued the Cross-State Air Pollution Rule (CSAPR) (discussed in detail below) in August 2011 to replace CAIR. The CSAPR was challenged in the courts. The United States Court of Appeals for the District of Columbia Circuit issued an order in December 2011 staying the effective date of the rule pending judicial review. In August 2012, a panel of the United States Court of Appeals for the District of Columbia Circuit issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the CAIR until a replacement rule is finalized. Nearly all of the states in which the Registrant Subsidiaries' power plants are located are covered by CAIR.

The Federal EPA issued final maximum achievable control technology (MACT) standards for coal and oil-fired power plants (discussed in detail below) in February 2012.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's requirement that certain facilities install best available retrofit technology (BART) to address regional haze in federal parks and other protected areas. BART requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through individual state implementation plans (SIPs) or, if SIPs are not adequate or are not developed on schedule, through federal implementation plans (FIPs). The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas and Oklahoma. The Federal EPA finalized a FIP for Oklahoma that contains more stringent control requirements for SO_2 emissions from affected units in that state. The Arkansas SIP was disapproved and the state is developing a revised submittal. In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the CSAPR trading programs to use those programs in place of source-specific BART for SO_2 and NO_x emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. This rule is being challenged in the United States Court of Appeals for the District of Columbia Circuit and its fate is uncertain given recent developments in the CSAPR litigation.

In 2009, the Federal EPA issued a final mandatory reporting rule for CO_2 and other greenhouse gases covering a broad range of facilities emitting in excess of 25,000 tons of CO_2 emissions per year. The Federal EPA issued a final endangerment finding for greenhouse gas emissions from new motor vehicles in 2009. The Federal EPA determined that greenhouse gas emissions from stationary sources will be subject to regulation under the CAA beginning January 2011 and finalized its proposed scheme to streamline and phase-in regulation of stationary source CO_2 emissions through the NSR prevention of significant deterioration and Title V operating permit programs through the issuance of final federal rules, SIP calls and FIPs. The Federal EPA is reconsidering whether to include CO_2 emissions in a number of stationary source standards, including standards that apply to new electric utility units and agreed to specific deadlines to issue proposed new source performance standards for utility boilers.

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for SO_2, NO_2 and lead, and is currently reviewing the NAAQS for ozone and PM. States are in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the new NAAQS and may develop additional requirements for facilities as a result of those evaluations. Management cannot currently predict the nature, stringency or timing of those requirements.

Notable developments in significant CAA regulatory requirements affecting the Registrant Subsidiaries' operations are discussed in the following sections.

Cross-State Air Pollution Rule (CSAPR)

In August 2011, the Federal EPA issued CSAPR. Certain revisions to the rule were finalized in March 2012. CSAPR relies on newly-created SO_2 and NO_x allowances and individual state budgets to compel further emission reductions from electric utility generating units in 28 states. Interstate trading of allowances is allowed on a restricted sub-regional basis. Arkansas and Louisiana are subject only to the seasonal NO_x program in the rule. Texas is subject to the annual programs for SO_2 and NO_x in addition to the seasonal NO_x program. The annual SO_2 allowance budgets in Indiana, Ohio and West Virginia were reduced significantly in the rule. A supplemental rule includes Oklahoma in the seasonal NO_x program. The supplemental rule was finalized in December 2011 with an increased NO_x emission budget for the 2012 compliance year. The Federal EPA issued a final Error Corrections Rule and further CSAPR revisions in 2012 to make corrections to state budgets and unit allocations and to remove the restrictions on interstate trading in the first phase of CSAPR.

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the United States Court of Appeals for the District of Columbia Circuit. Several of the petitioners filed motions to stay the implementation of the rule pending judicial review. In December 2011, the court granted the motions for stay. In August 2012, the panel issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the CAIR until a replacement rule is finalized. The majority determined that the CAA does not allow the Federal EPA to "over control" emissions in an upwind state and that the Federal EPA exceeded its statutory authority by failing to allow states an opportunity to develop their own implementation plans before issuing a FIP. The Federal EPA and other respondents filed petitions for rehearing but in January 2013, the United States Court of Appeals for the District of Columbia Circuit denied all petitions for rehearing. Separate appeals of the supplemental rule, the Error Corrections Rule and the further revisions have been filed, but are being held in abeyance.

The time frames and stringency of the required emission reductions, coupled with the lack of robust interstate trading and the elimination of historic allowance banks, pose significant concerns for the AEP System and its electric utility customers. Management cannot predict the outcome of the pending litigation.

Mercury and Other Hazardous Air Pollutants Regulation

In February 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for mercury, PM (as a surrogate for particles of nonmercury metal) and hydrogen chloride (as a surrogate for acid gases) for units burning coal on a site-wide 30-day rolling average basis. In addition, the rule proposes work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. The effective date of the final rule was April 16, 2012 and compliance is required within three years. The AEP System is participating through various organizations in the petitions for administrative reconsideration and judicial review that have been filed. In November 2012, the Federal EPA published a notice announcing that it would accept comments on its reconsideration of certain issues related to the new source standards, including clarification of the requirements that apply during periods of start-up and shut down, measurement issues and the application of variability factors that may have an impact on the level of the standards. It is uncertain whether any of the information generated during the reconsideration process will affect the standards for existing sources.

The final rule contains a slightly less stringent PM limit than the original proposal and allows operators to exclude periods of startup and shutdown from the emissions averaging periods. The compliance time frame remains a serious concern. A one-year administrative extension may be available if the extension is necessary for the installation of controls or to avoid a serious reliability problem. In addition, the Federal EPA issued an enforcement policy describing the circumstances under which an administrative consent order might be issued to provide a fifth year for the installation of controls or completion of reliability upgrades. Management is concerned about the availability of compliance extensions and the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines. The AEP System is participating in petitions for review filed in the United States Court of Appeals for the District of Columbia Circuit by several organizations of which companies in the AEP System are members. Certain issues related to the standards for new coal-fired units have been severed from the main case and are being held in abeyance pending completion of the Federal EPA's reconsideration proceeding. The case is proceeding on the remaining issues and briefing is scheduled to be completed by April 2013.

Regional Haze – Oklahoma Affecting PSO

In March 2011, the Federal EPA proposed to approve in part and disapprove in part the regional haze SIP submitted by the State of Oklahoma through the Department of Environmental Quality. The Federal EPA proposed to approve all of the NO_x control measures in the SIP and disapprove the SO_2 control measures for six electric generating units, including two units owned by PSO. The Federal EPA proposed a FIP that would require these units to install technology capable of reducing SO_2 emissions to 0.06 pounds per million British thermal units within three years of the effective date of the FIP. The Federal EPA finalized the FIP in December 2011 that mirrored the proposed rule but established a five-year compliance schedule. PSO filed a petition for review of the FIP in the Tenth Circuit Court of Appeals and engaged in settlement discussions with the Federal EPA, the State of Oklahoma and other parties. In November 2012, PSO notified the court that the parties had reached agreement on a settlement that would provide for submission of a revised Regional Haze SIP requiring the retirement of one coal-fired unit of PSO's Northeastern Station no later than 2016, installation of emission controls on the second coal-fired Northeastern unit in 2016 and retirement of the second unit no later than 2026. Notice of the proposed settlement was published in the Federal Register in November 2012 and the comment period has closed. The Tenth Circuit Court of Appeals is holding the appeal in abeyance pending implementation of the settlement.

CO_2 Regulation

In March 2012, the Federal EPA issued a proposal to regulate CO_2 emissions from new fossil fuel-fired electricity generating units. The proposed rule establishes a new source performance standard of 1,000 pounds of CO_2 per megawatt hour of electricity generated, a rate that most natural gas combined cycle units can meet, but that is substantially below the emission rate of a new pulverized coal generator or an integrated gas combined cycle unit that uses coal for fuel. As proposed, the rule does not apply to new gas-fired stationary combustion turbines used as peaking units, does not apply to existing, modified or reconstructed sources and does not apply to units whose CO_2 emission rate increases as a result of the addition of pollution control equipment to control criteria pollutant emissions or HAPs. The rule is not anticipated to have a significant immediate impact on the AEP System since it does not apply to existing units or units that have already commenced construction. The comment period closed in June 2012. New source performance standards affect units that have not yet received permits, but complete the permitting process while the proposal is pending. The proposed standards were challenged in the United States Court of Appeals for the District of Columbia Circuit. That case was dismissed because the court determined that no final agency action had yet been taken. The Federal EPA is expected to finalize these standards in 2013.

In June 2012, the United States Court of Appeals for the District of Columbia Circuit issued a decision upholding, in all material respects, the Federal EPA's endangerment finding, its regulatory program for CO_2 emissions from new motor vehicles and its plan to phase-in regulation of CO_2 emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. A petition for rehearing was filed which the court denied in December 2012. Petitioners may seek further review in the U.S. Supreme Court.

The Federal EPA also finalized a rule in June 2012 that retains the current thresholds for permitting stationary sources under the PSD and Title V operating permit programs at 100,000 tons per year for new sources and 75,000 tons per year for modified sources. The Federal EPA also confirmed that it will re-evaluate these thresholds during its five-year review in 2016. The AEP System's generating units are large sources of CO_2 emissions and management will continue to evaluate permitting obligations in light of these thresholds.

Coal Combustion Residual Rule

In June 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at coal-fired electric generating units. The rule contains two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials and another would allow states to retain primary authority to regulate the beneficial re-use and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and would require existing unlined surface impoundments to upgrade to the new standards or stop receiving coal ash and initiate closure within five years of the issuance of a final rule. In 2011, the Federal EPA issued a notice of data availability requesting comments on a number of technical reports and other data received during the comment period for the original proposal and requesting comments on potential modeling analyses to update its risk assessment. The Federal EPA has also announced its intention to complete a risk assessment of various beneficial uses of coal ash. Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. The Federal EPA opposed the petition and is seeking additional time to coordinate the issuance of a final rule with the issuance of new effluent limitations under the Clean Water Act for utility facilities.

Currently, approximately 40% of the coal ash and other residual products from the AEP System's generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. Certain of these uses would no longer be available and others are likely to significantly decline if coal ash and related materials are classified as hazardous wastes. In addition, surface impoundments and landfills to manage these materials are currently used at the generating facilities. The Registrant Subsidiaries will incur significant costs to upgrade or close and replace their existing facilities under the proposed solid waste management alternative. Regulation of these materials as hazardous wastes would significantly increase these costs. As the rule is not final, management is unable to determine a range of potential costs that are reasonably possible of occurring but expect the costs to be significant.

Clean Water Act Regulations

In April 2011, the Federal EPA issued a proposed rule setting forth standards for existing power plants that will reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. Entrainment is when small fish, eggs or larvae are drawn into the cooling water system and affected by heat, chemicals or physical stress. The proposed standards affect all plants withdrawing more than two million gallons of cooling water per day and establish specific intake design and intake velocity standards meant to allow fish to avoid or escape impingement. Compliance with this standard is required within eight years of the effective date of the final rule. The proposed standard for entrainment for existing facilities requires a site-specific evaluation of the available measures for reducing entrainment. The proposed entrainment standard for new units at existing facilities requires either intake flows commensurate with closed cycle cooling or achieving entrainment reductions equivalent to 90% or greater of the reductions that could be achieved with closed cycle cooling. Plants withdrawing more than 125 million gallons of cooling water per day must submit a detailed technology study to be reviewed by the state permitting authority. Management is evaluating the proposal and engaged in the collection of additional information regarding the feasibility of implementing this proposal at the AEP System's facilities. In June 2012, the Federal EPA issued additional Notices of Data Availability and requested public comments. The AEP System submitted comments in July 2012. Issuance of a final rule is not expected until June 2013. Management is preparing to begin activities to implement the rule following its issuance and an analysis of the final requirements.

In addition, the Federal EPA issued an information collection request and is developing revised effluent limitation guidelines for electricity generating facilities. A proposed rule is expected in 2013 and a final rule in 2014. Management is unable to predict the impact of these changes but expect the costs to be significant.

Climate Change

National public policy makers and regulators in the 10 states the Registrant Subsidiaries serve have diverse views on climate change. Management is currently focused on responding to these emerging views with prudent actions, such as improving energy efficiency, investing in developing cost-effective and less carbon-intensive technologies and evaluating assets across a range of plausible scenarios and outcomes. Management is also an active participant in a variety of public policy discussions at state and federal levels to assure that proposed new requirements are feasible and the economies of the states served are not placed at a competitive disadvantage.

While comprehensive economy-wide regulation of CO_2 emissions might be achieved through future legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO_2 emissions under the existing requirements of the CAA.

Several states have adopted programs that directly regulate CO_2 emissions from power plants. The majority of the states where the Registrant Subsidiaries have generating facilities passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements. The Registrant Subsidiaries are taking steps to comply with these requirements. In order to meet these requirements and as a key part of AEP's corporate sustainability effort, management pledged to increase wind power. By the end of 2012, the AEP System secured, through power purchase agreements, 1,994 MW of wind and solar power.

The AEP System has taken measurable, voluntary actions to reduce and offset CO_2 emissions. The AEP System participates in a number of voluntary programs to monitor, mitigate and reduce CO_2 emissions, but many of these programs have been discontinued due to anticipated legislative or regulatory actions. Management estimates that 2012 emissions were approximately 122 million metric tons.

Certain groups have filed lawsuits alleging that emissions of CO_2 are a "public nuisance" and seeking injunctive relief and/or damages from small groups of coal-fired electricity generators, petroleum refiners and marketers, coal companies and others. The Registrant Subsidiaries have been named in pending lawsuits, which management is defending. It is not possible to predict the outcome of these lawsuits or their impact on operations or financial condition. See "Carbon Dioxide Public Nuisance Claims" and "Alaskan Villages' Claims" sections of Note 4.

Future federal and state legislation or regulations that mandate limits on the emission of CO_2 could result in significant increases in capital expenditures and operating costs, which, in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force the Registrant Subsidiaries to close some coal-fired facilities and could lead to possible impairment of assets. Public perception may ultimately have a significant impact on future legislation and regulation that could adversely affect the Registrant Subsidiaries' ability to recover their investments in coal-fired plants.

Climate change and its resultant impact on weather patterns could modify the Registrant Subsidiaries' customers' power usage. Customers' energy needs currently vary with weather conditions and the economy. Increased or decreased energy usage could require the acquisition or construction of more generation and transmission assets or cause early retirement of such assets. The timing and duration of extreme weather conditions may require more system backup and contribute to increased system stresses, including service interruptions and increased storm restoration costs. Extreme weather conditions that create high energy demand could raise electricity prices, which could increase the cost of energy provided to customers and could provide opportunity for increased wholesale sales and higher margins.

To the extent climate change impacts a region's economic health, it could also affect revenues. The Registrant Subsidiaries' financial performance is tied to the health of the regional economies served. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods, has an impact on the economic health of communities served. The cost of additional regulatory requirements would normally be borne by consumers through higher prices for energy and purchased goods.

FINANCIAL CONDITION

BUDGETED CONSTRUCTION EXPENDITURES

The 2013 estimated construction expenditures by Registrant Subsidiary include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	2013 Budgeted Construction Expenditures					
Company	Environmental	Generation	Transmission	Distribution	Other	Total
			(in millions)			
APCo	$ 59	$ 87	$ 67	$ 145	$ 12	$ 370
I&M	42	293	49	89	11	484
OPCo	191	99	79	216	32	617
PSO	64	48	48	127	8	295
SWEPCo	143	82	86	79	8	398

For 2014 and 2015, management forecasts annual construction expenditures for the AEP System of $3.8 billion each year. The budgeted amounts exclude equity AFUDC and capitalized interest. The projected increases are generally the result of required environmental investment to comply with Federal EPA rules and additional transmission spending. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. These construction expenditures will be funded through cash flows from operations and financing activities. Generally, the Registrant Subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged.

SIGNIFICANT TAX LEGISLATION

The Small Business Jobs Act, enacted in September 2010, included 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, this act extended the time for claiming bonus depreciation and increased the deduction to 100% starting in September 2010 through 2011 and decreased the deduction to 50% for 2012. The American Taxpayer Relief Act of 2012 provided for the extension of several business and energy industry tax deductions and credits, including the one year extension of 50% bonus depreciation to 2013.

The enacted provisions had no material impact on the Registrant Subsidiaries' net income, financial condition or cash flows in 2012, but are expected to result in material future cash flow benefits.

CYBER SECURITY

Cyber security presents a heightened risk for electric utility systems because a cyber-attack could affect critical energy infrastructure. Breaches to the cyber security of the grid or the AEP System are potentially disruptive to people, property and commerce and create risk for business, investors and customers. In February 2013, President Obama signed an executive order that addresses how government agencies will operate and support the functions in cyber security as well as redefine how the government interfaces with critical infrastructure, such as the electric grid. The AEP System already operates under regulatory cyber security standards to protect critical infrastructure. The cyber security framework that will be developed through this executive order will be reviewed by the FERC. Management expects the AEP System to participate in the process and will share best practices already in place. Critical cyber assets, such as data centers and transmission operations centers and business network are protected, using multiple layers of cyber security and authentication. The AEP System is constantly scanned for risks or threats.

Cyber hackers have been able to breach a number of very secure facilities, from federal agencies, banks and retailers to social media sites. As these events become known and develop, cyber security tools and processes are continually assessed to determine where defenses might need strengthened.

In recent years, management has taken several steps to enhance capabilities for identifying risks or threats. AEP became the first utility in the country to build a Cyber Security Operations Center. Funding was included as part of a larger American Recovery and Reinvestment Act Department of Energy Smart Grid Demonstration Project grant. This facility is designed as a pilot cyber threat and information-sharing center specifically for the electric sector.

AEP has partnered with a nonaffiliated entity to leverage their experience and technical capabilities, which were developed through their work with the U.S. Department of Defense. AEP works with a consortium of other utilities across the country, learning how best to share information about potential threats and collaborating with each other and with the Department of Homeland Security. AEP also worked with a nonaffiliated entity to conduct several seminars in 2011 about recognizing and investigating cyber vulnerabilities. Through these types of efforts, AEP is working to protect itself while helping the industry advance its cyber security capabilities.

In March 2012, AEP signed a cooperative research and development agreement with the Department of Homeland Security's Office of Cyber Security and Communications, further enhancing the ability to directly exchange information about cyber threats. In addition, AEP continues to partner with a number of federal and industry groups to advance the national capabilities of cyber security. Among them is the U.S. Department of Energy, where AEP is working on several pilot projects covering advanced cyber security and assessment tools.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. Management considers an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on net income or financial condition.

Management discusses the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee reviews the disclosures relating to them.

Management believes that the current assumptions and other considerations used to estimate amounts reflected in the financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about the Registrant Subsidiaries' critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required

The financial statements of the Registrant Subsidiaries with cost-based rate-regulated operations (APCo, I&M, PSO, SWEPCo and a portion of OPCo) 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.

The Registrant Subsidiaries recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, the Registrant Subsidiaries match the timing of expense and income recognition with regulated revenues. Liabilities are also recorded for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used

When incurred costs are probable of recovery through regulated rates, the Registrant Subsidiaries record them as regulatory assets on the balance sheet. Management reviews the probability of recovery at each balance sheet date and whenever new events occur. Similarly, the Registrant Subsidiaries record regulatory liabilities when a determination is made that a refund is probable or when ordered by a commission. Examples of new events that affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs as well as the return of revenues, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, that regulatory asset is written-off as a charge against earnings. A write-off of regulatory assets or establishment of a regulatory liability may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used

A change in the above assumptions may result in a material impact on net income. Refer to Note 3 for further detail related to regulatory assets and liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

The Registrant Subsidiaries record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. In accordance with the applicable state commission regulatory treatment in Arkansas, Louisiana, Oklahoma and Texas, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

The changes in unbilled electricity utility revenues for the years ended December 31, 2012, 2011 and 2010 were as follows:

	Years Ended December 31,		
Company	**2012**	**2011**	**2010**
		(in thousands)	
APCo	$ 8,047	$ (41,979)	$ 30,337
I&M	(1,233)	(2,628)	2,194
OPCo	(14,721)	(20,449)	9,864
PSO	5,213	641	(4,159)
SWEPCo	2,302	643	(1,175)

Assumptions and Approach Used

For each Registrant Subsidiary, the monthly estimate for unbilled revenues is computed as net generation less the current month's billed KWh plus the prior month's unbilled KWh. However, due to meter reading issues, meter drift and other anomalies, a separate monthly calculation limits the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWh to the current month and previous month, on a cycle-by-cycle basis, and dividing the current month aggregated result by the billed KWh. The limits are statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

Effect if Different Assumptions Used

Significant fluctuations in energy demand for the unbilled period, weather, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1% of the accrued unbilled revenues.

Accounting for Derivative Instruments

Nature of Estimates Required

Management considers fair value techniques, valuation adjustments related to credit and liquidity and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used

The Registrant Subsidiaries measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based primarily on exchange prices and broker quotes. If a quoted market price is not available, the fair value is estimated based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

The Registrant Subsidiaries reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. Liquidity adjustments are calculated by utilizing bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. Credit adjustments on risk management contracts are calculated using estimated default probabilities and recovery rates relative to the counterparties or counterparties with similar credit profiles and contractual netting agreements. With respect to hedge accounting, management assesses hedge effectiveness and evaluates a forecasted transaction's probability of occurrence within the specified time period as provided in the original hedge documentation.

Effect if Different Assumptions Used

There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts settle.

The probability that hedged forecasted transactions will not occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding derivatives, hedging and fair value measurements, see Notes 8 and 9. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of "Property, Plant and Equipment" accounting guidance, the Registrant Subsidiaries evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable including planned abandonments and a probable disallowance for rate-making on a plant under construction or the assets meet the held-for-sale criteria. The Registrant Subsidiaries utilize a group composite method of depreciation to estimate the useful lives of long-lived assets. The evaluations of long-lived, held-and-used assets may result from abandonments, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount is not recoverable, the Registrant Subsidiary records an impairment to the extent that the fair value of the asset is less than its book value. Performing an impairment evaluation involves a significant degree of estimation and judgment in areas such as identifying circumstances that indicate an impairment may exist, identifying and grouping affected assets and developing the undiscounted and discounted future cash flows (used to estimate fair value in the absence of market-based value, in some instances) associated with the asset. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. For regulated assets, the earnings impact of an impairment charge could be offset by the establishment of a regulatory asset, if rate recovery is probable. For nonregulated assets, any impairment charge is recorded against earnings.

Assumptions and Approach Used

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, management estimates fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. Cash flow estimates are based on relevant information available at the time the estimates are made. Estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results. Also, when measuring fair value, management evaluates the characteristics of the asset or liability to determine if market participants would take those characteristics into account when pricing the asset or liability at the measurement date. Such characteristics include, for example, the condition and location of the asset or restrictions of the use of the asset. Management performs depreciation studies that include a review of any external factors that may affect the useful life to determine composite depreciation rates and related lives which are subject to periodic review by state regulatory commissions for cost-based regulated assets. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used

In connection with the evaluation of long-lived assets in accordance with the requirements of "Property, Plant and Equipment" accounting guidance, the fair value of the asset can vary if different estimates and assumptions would have been used in the applied valuation techniques. The estimate for depreciation rates takes into account the history of interim capital replacements and the amount of salvage expected. In cases of impairment, the best estimate of fair value was made using valuation methods based on the most current information at that time. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and management's analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

AEP maintains a qualified, defined benefit pension plan (Qualified Plan), which covers substantially all nonunion and certain union employees, and unfunded, nonqualified supplemental plans (Nonqualified Plans) to provide benefits in excess of amounts as permitted under the provisions of the tax law for participants in the Qualified Plan (collectively the Pension Plans). Additionally, AEP entered into individual employment contracts with certain current and retired executives that provide additional retirement benefits as a part of the Nonqualified Plans. AEP also sponsors other postretirement benefit plans to provide health and life insurance benefits for retired employees (Postretirement Plans). The Pension Plans and Postretirement Plans are collectively referred to as the Plans. The Registrant Subsidiaries participate in the 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. See Note 6 for information regarding costs and assumptions for employee retirement and postretirement benefits.

The following table shows the net periodic cost by Registrant Subsidiary for the Plans:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
Net Periodic Cost	2012	2011	2010	2012	2011	2010
	(in thousands)					
APCo	$ 16,646	$ 15,146	$ 15,818	$ 15,540	$ 13,301	$ 19,048
I&M	16,563	15,205	20,138	11,358	9,360	13,857
OPCo	18,978	19,418	19,701	20,282	16,651	24,112
PSO	7,495	7,388	5,439	4,821	3,881	7,443
SWEPCo	8,307	7,488	7,096	5,928	4,841	7,574

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2013, management evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Management also considered historical returns of the investment markets and changes in tax rates which affect a portion of the Postretirement Plans' assets. Management anticipates that the investment managers employed for the Plans will invest the assets to generate future returns averaging 6.5% for the Qualified Plan and 7% for the Postretirement Plans.

The expected long-term rate of return on the Plans' assets is based on AEP's targeted asset allocation and expected investment returns for each investment category. Assumptions for the Plans are summarized in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
	2013 Target Asset Allocation	**Assumed/ Expected Long-Term Rate of Return**	**2013 Target Asset Allocation**	**Assumed/ Expected Long-Term Rate of Return**
Equity	40 %	9.00 %	66 %	8.60 %
Fixed Income	50 %	4.00 %	33 %	3.50 %
Other Investments	10 %	8.80 %	-%	- %
Cash and Cash Equivalents	-%	-%	1 %	1.50 %
Total	100 %		100 %	

Management regularly reviews the actual asset allocation and periodically rebalances the investments to the targeted allocation. Management believes that 6.5% and 7% are reasonable estimates of the long-term rate of return on the Plans' assets. The Pension Plans' assets had an actual gain of 13.8% and 8.1% for the years ended December 31, 2012 and 2011, respectively. The Postretirement Plans' assets had an actual gain of 15.4% and 0.4% for the years ended December 31, 2012 and 2011, respectively. Management will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

AEP bases the determination of pension expense or income 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. As of December 31, 2012, AEP had cumulative gains of approximately $302 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial gains may result in decreases in the future pension costs depending on several factors, including whether such gains at each measurement date exceed the corridor in accordance with "Compensation – Retirement Benefits" accounting guidance. See the table below for the amount of cumulative gains by Registrant Subsidiary.

Cumulative Gains – Deferred Asset Gain	**December 31, 2012**
	(in thousands)
APCo	$ 39,913
I&M	35,447
OPCo	65,183
PSO	17,005
SWEPCo	17,960

The method used to determine the discount rate that AEP utilizes for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate as of December 31, 2012 under this method was 3.95% for the Qualified Plan, 3.8% for the Nonqualified Plans and 3.95% for the Postretirement Plans. Due to the effect of the unrecognized actuarial gains and based on an expected rate of return on the Pension Plans' assets of 6.5%, a discount rate of 3.95% and 3.8% and various other assumptions, management estimates that the pension costs by Registrant Subsidiary for all pension plans will approximate the amounts in the following table. Based on an expected rate of return on the OPEB plans' assets of 7%, a discount rate of 3.95% and various other assumptions, management estimates Postretirement Plan costs (credits) by Registrant Subsidiary will approximate the amounts in the following table.

Estimated Postretirement Plan Costs (Credits)	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2013	2014	2015	2013	2014	2015
	(in thousands)					
APCo	$ 22,556	$ 16,753	$ 12,791	$ 106	$ (886)	$ (2,195)
I&M	21,881	16,332	12,428	(3,101)	(3,598)	(4,370)
OPCo	27,866	19,771	14,214	1,994	770	(713)
PSO	10,656	8,423	7,037	(1,653)	(1,851)	(2,202)
SWEPCo	11,394	8,758	7,002	(2,134)	(2,356)	(2,739)

Future actual costs will depend on future investment performance, changes in future discount rates and various other factors related to each Registrant Subsidiary's populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the "Effect if Different Assumptions Used" section below.

In November 2012, management announced changes to the retiree medical coverage. Effective for retirements after December 2012, management capped contributions to retiree medical costs reducing the Registrant Subsidiaries' future exposure to medical cost inflation. Effective for employees hired after December 2013, retiree medical coverage will not be provided. This change will reduce costs of the plan beginning in 2013 as shown by the estimated credits for Postretirement Plans in the previous table.

The value of AEP's Pension Plans' assets increased to $4.7 billion as of December 31, 2012 from $4.3 billion as of December 31, 2011 primarily due to investment returns and a $200 million contribution from AEP System companies. During 2012, the Qualified Plan paid $367 million and the Nonqualified Plans paid $16 million in benefits to plan participants. The value of AEP's Postretirement Plans' assets increased to $1.6 billion as of December 31, 2012 from $1.4 billion as of December 31, 2011 primarily due to investment returns and contributions from AEP System companies and the participants. The Postretirement Plans paid $151 million in benefits to plan participants during 2012. See Note 6 for complete details by Registrant Subsidiary.

Nature of Estimates Required

The Registrant Subsidiaries participate in AEP sponsored pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. These benefits are accounted for under "Compensation" and "Plan Accounting" accounting guidance. The measurement of pension and postretirement benefit obligations, costs and liabilities is dependent on a variety of assumptions.

Assumptions and Approach Used

The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Compensation increase rate
- Cash balance crediting rate
- Health care cost trend rate
- Expected return on plan assets

Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used

The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

APCo

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
	(in thousands)			
Effect on December 31, 2012 Benefit Obligations				
Discount Rate	$ (38,174)	$ 42,021	$ (19,078)	$ 21,054
Compensation Increase Rate	1,060	(951)	NA	NA
Cash Balance Crediting Rate	3,318	(2,813)	NA	NA
Health Care Cost Trend Rate	NA	NA	9,317	(10,984)
Effect on 2012 Periodic Cost				
Discount Rate	(2,274)	2,464	(2,014)	2,238
Compensation Increase Rate	589	(539)	NA	NA
Cash Balance Crediting Rate	1,524	(1,346)	NA	NA
Health Care Cost Trend Rate	NA	NA	3,648	(3,259)
Expected Return on Plan Assets	(3,037)	3,037	(1,145)	1,151

I&M

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
	(in thousands)			
Effect on December 31, 2012 Benefit Obligations				
Discount Rate	$ (34,813)	$ 38,485	$ (11,845)	$ 13,093
Compensation Increase Rate	1,557	(1,420)	NA	NA
Cash Balance Crediting Rate	4,281	(3,694)	NA	NA
Health Care Cost Trend Rate	NA	NA	3,951	(5,297)
Effect on 2012 Periodic Cost				
Discount Rate	(1,964)	2,128	(1,266)	1,402
Compensation Increase Rate	508	(466)	NA	NA
Cash Balance Crediting Rate	1,317	(1,162)	NA	NA
Health Care Cost Trend Rate	NA	NA	2,302	(2,064)
Expected Return on Plan Assets	(2,623)	2,623	(830)	834

OPCo

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in thousands)			
Effect on December 31, 2012 Benefit Obligations				
Discount Rate	$ (54,592)	$ 59,980	$ (27,795)	$ 31,043
Compensation Increase Rate	1,869	(1,705)	NA	NA
Cash Balance Crediting Rate	4,727	(4,301)	NA	NA
Health Care Cost Trend Rate	NA	NA	15,452	(17,221)
Effect on 2012 Periodic Cost				
Discount Rate	(3,406)	3,690	(2,692)	2,990
Compensation Increase Rate	882	(807)	NA	NA
Cash Balance Crediting Rate	2,282	(2,015)	NA	NA
Health Care Cost Trend Rate	NA	NA	4,880	(4,361)
Expected Return on Plan Assets	(4,542)	4,542	(1,567)	1,574

PSO

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in thousands)			
Effect on December 31, 2012 Benefit Obligations				
Discount Rate	$ (13,015)	$ 14,209	$ (5,439)	$ 6,010
Compensation Increase Rate	941	(864)	NA	NA
Cash Balance Crediting Rate	2,842	(3,629)	NA	NA
Health Care Cost Trend Rate	NA	NA	1,705	(2,369)
Effect on 2012 Periodic Cost				
Discount Rate	(913)	990	(578)	639
Compensation Increase Rate	237	(217)	NA	NA
Cash Balance Crediting Rate	612	(540)	NA	NA
Health Care Cost Trend Rate	NA	NA	1,051	(943)
Expected Return on Plan Assets	(1,218)	1,218	(387)	389

SWEPCo

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in thousands)			
Effect on December 31, 2012 Benefit Obligations				
Discount Rate	$ (13,402)	$ 14,642	$ (6,135)	$ 6,787
Compensation Increase Rate	1,068	(978)	NA	NA
Cash Balance Crediting Rate	4,688	(4,426)	NA	NA
Health Care Cost Trend Rate	NA	NA	1,580	(2,327)
Effect on 2012 Periodic Cost				
Discount Rate	(929)	1,006	(637)	705
Compensation Increase Rate	241	(220)	NA	NA
Cash Balance Crediting Rate	622	(549)	NA	NA
Health Care Cost Trend Rate	NA	NA	1,160	(1,040)
Expected Return on Plan Assets	(1,238)	1,238	(427)	429

NA Not applicable.

ACCOUNTING PRONOUNCEMENTS

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, management cannot determine the impact on the reporting of the Registrant Subsidiaries' operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, financial instruments, leases, insurance, hedge accounting and consolidation policy. The ultimate pronouncements resulting from these and future projects could have an impact on future net income and financial position.

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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

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

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Ohio Power Company	End of 2012/Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

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

The CPA Certification Statement should:

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

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

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

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

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

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

(3) 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

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

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

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

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

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

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

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Ohio Power Company	02 Year/Period of Report End of 2012/Q4
03 Previous Name and Date of Change *(if name changed during year)*	/ /
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 1 Riverside Plaza, Columbus, Ohio 43215-2373	
05 Name of Contact Person Jason M. Johnson	06 Title of Contact Person Accountant
07 Address of Contact Person *(Street, City, State, Zip Code)* AEP Service Corporation, 1 Riverside Plaza, Columbus, Ohio 43215-2373	

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

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Andrew B. Reis		
02 Title Assistant Controller	Andrew B. Reis	04/11/2013

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

LIST OF SCHEDULES (Electric Utility)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	None
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	None
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	None
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	None
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	None
66	Generating Plant Statistics Pages	410-411	None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [ ] Two copies will be submitted [ ] No annual report to stockholders is prepared		

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2012/Q4

GENERAL INFORMATION

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

Andrew B. Reis, Assistant Controller
1 Riverside Plaza
Columbus, Ohio 43215-2373

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

Ohio - May 8, 1907
Reorganized - December 18, 1924

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

None

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

Electric - Ohio

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 the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

CONTROL OVER RESPONDENT

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

American Electric Power Company, Inc.

Ownership of 100% of the Common Stock.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Cardinal Operating Company	Operates Generating Station	50	(a)
2				
3	Central Coal Company	Coal Mining - Inactive	50	(b)
4				
5	Conesville Coal Preparation Company	Provides coal washing	100	
6		services for one of the		
7		Company's generating		
8		stations. Became inactive		
9		in 2012.		
10	(a) Joint Control			
11	- Buckeye Power, Inc.			
12	(b) Joint Control			
13	- Appalachian Power Company			
14	(Associated Company)			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	See Footnote		
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	/ /	2012/Q4

FOOTNOTE DATA

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

Executive Compensation Table

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

Name and Principal Position (a)	Salary ($)(1) (b)	Bonus ($) (c)	Stock Awards ($)(2) (d)	Option Awards ($) (e)	Non-Equity Incentive Plan Compensation ($)(3) (f)	Change in Pension Value and Non-qualified Deferred Compensation Earnings ($)(4) (g)	All Other Compensation Earnings ($)(5) (h)	Total ($) (i)
Nicholas K. Akins — President and Chief Executive Officer	903,461	—	4,600,008	—	1,500,000	176,312	106,709	7,286,490
Brian X. Tierney — Executive Vice President and Chief Financial Officer	652,500	—	1,896,860	—	800,000	228,760	49,467	3,627,587
Robert P. Powers — Executive Vice President and Chief Operating Officer	652,500	—	1,896,860	—	800,000	586,359	60,809	3,996,528
Dennis E. Welch(6) — Executive Vice President and Chief External Officer	465,283	—	920,291	—	415,000	81,405	39,275	1,921,254
David M. Feinberg(7) — Executive Vice President and General Counsel	451,731	—	857,807	—	450,000	30,361	37,044	1,826,943

(1) Amounts in the salary column are composed of executive salaries paid for the year shown, which include 261 days of pay for 2012, which is one day more than the standard 260 calendar work days and holidays in a year.

(2) The amounts reported in this column reflect the total grant date fair value, calculated in accordance with FASB ASC Topic 718, of performance units and restricted stock units granted under our Long-Term Incentive Plan. See Note 14 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2012 for a discussion of the relevant assumptions used in calculating these amounts. The restricted stock units vest over a forty month period. The value realized for the performance units, if any, will depend on the Company's performance during a three-year performance and vesting period. The potential payout can range from 0 percent to 200 percent of the target number of performance units. Therefore, the maximum amount payable for the performance units is equal to $5,520,010 for Mr. Akins, $2,276,232 for Mr. Tierney, $2,276,232 for Mr. Powers, $1,104,350 for Mr. Welch and $1,029,368 for Mr. Feinberg.

(3) The amounts shown in this column are annual incentive awards made under the Senior Officer Incentive Plan for the year shown. At the outset of each year, the HR Committee sets annual incentive targets and performance criteria that are used after year-end to determine if and the extent to which executive officers may receive annual incentive award payments under this plan.

(4) The amounts shown in this column are attributable to the increase in the actuarial values of each of the named executive officer's combined benefits under AEP's qualified and non-qualified defined benefit plans determined using interest rate and mortality assumptions consistent with those used in the Company's financial statements. No named executive officer received preferential or above-market earnings on deferred compensation. See Note 7 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2012, for a discussion of the relevant assumptions.

(5) Amounts shown in the All Other Compensation column for 2012 include: (a) Company contributions to the Company's Retirement Savings Plan, (b) Company contributions to the Company's Supplemental Retirement Savings Plan, (c) perquisites and (d) for Mr. Akins, a tax gross-up associated with a reimbursement for a Company-caused tax penalty. The amounts are listed in the following table:

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2012/Q4

FOOTNOTE DATA

All Other Compensation

Type	Nicholas K. Akins	Brian X. Tierney	Robert P. Powers	Dennis E. Welch	David M. Feinberg
Retirement Savings Plan Match	11,250	11,250	11,250	11,250	11,250
Supplemental Retirement Savings Plan Match	63,000	38,217	38,250	16,846	16,356
Perquisites	28,385	-	11,309	11,179	9,438
Tax Gross-Up	4,074	-	-	-	-
Total	106,709	49,467	60,809	39,275	37,044

Perquisites provided in 2012 included: financial counseling and tax preparation, air and hotel club memberships, and, for Mr. Akins, director's accidental death insurance premium and on one occasion, personal use of Company aircraft for a death in the family. None of the individual perquisites had a value exceeding $25,000 for a named executive officer.

(6) Mr. Welch was not considered an executive officer prior to 2012.

(7) Mr. Feinberg was not considered an executive officer prior to 2012.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1		
2	Nicholas K. Akins, Chairman of the Board	Columbus, Ohio
3	and Chief Executive Officer	
4		
5	Lisa M. Barton, Vice President	Columbus, Ohio
6		
7	David M. Feinberg, Secretary	Columbus, Ohio
8		
9	Mark C. McCullough, Vice President	Columbus, Ohio
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11	Robert P. Powers, Vice President	Columbus, Ohio
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13	Brian X. Tierney, Vice President	Columbus, Ohio
14	and Chief Financial Officer	
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16	Dennis E. Welch, Vice President	Columbus, Ohio
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18	Barbara D. Radous, Vice President	Columbus, Ohio
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25	Note: The Respondent does not have an Executive Committee	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

Does the respondent have formula rates?

[X] Yes
[ ] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	PJM Interconnection L.L.C. Attachment H-14	ER08-1329
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Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

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

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[X] Yes
[ ] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20120525-5106	05/25/2012	ER08-1329	AEP PJM OATT Formula Updat	PJM OATT Attachment H-14
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
1	Not Applicable			
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	/ /	2012/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1.

Date Acquired Or Extended	Community	Period of Franchise & Termination	Consideration
Renewed on January 6, 2012	Village of Newcomerstown, State of Ohio	Ten (10) year franchise renewal expiring on January 6, 2022	None
Renewed on January 9, 2012	Village of Rio Grande, State of Ohio	Twenty-five (25) year franchise renewal expiring on January 9, 2037	None
Renewed on May 7, 2012	Village of Fredericktown, State of Ohio	Ten (10) year franchise renewal expiring on May 7, 2022	None
Renewed on May 15, 2012	Village of Adena, State of Ohio	Ten (10) year franchise renewal expiring on May 15, 2022	None
Renewed on July 11, 2012	Village of New Concord, State of Ohio	Ten (10) year franchise renewal expiring on July 11, 2022	None
Renewed on July 18, 2012	Village of East Canton, State of Ohio	Twenty-five (25) year franchise renewal expiring on July 18, 2037	None
Renewed on September 10, 2012	Village of Sugar Grove, State of Ohio	Twenty-five (25) year franchise renewal expiring on September 10, 2037	None
Renewed on September 13, 2012	Village of Pleasantville, State of Ohio	Twenty-five (25) year franchise renewal expiring on September 13, 2037	None
Renewed on October 16, 2012	Village of Glouster, State of Ohio	Twenty-five (25) year franchise renewal expiring on October 16, 2037	None

2. None

3. None

4. None

5. None

6. None

7. None

8. Transmission Line employees represented by Local IBEW #1466-1 were provided with a 2% general wage increase effective April 1, 2012

Newark, Zanesville employees represented by Local IBEW #1466-2 were provided with a 2% general wage increase effective April 1, 2012

Columbus, Athens, Chillocothe employees represented by Local IBEW #1466-3 were provided with a 2% general wage increase effective April 1, 2012

Steubenville employees represented by Local IBEW #696 were provided with a 2% general wage increase effective April 1, 2012

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2012/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

Cardinal Plant employees represented by UWUA Local #478 were provided with a 2% general wage increase effective June 1, 2012

Kammer Plant employees represented by UWUA Local #468 were provided with a 2% general wage increase effective June 1, 2012

Mitchell Plant employees represented by UWUA Local #492 were provided with a 2% general wage increase effective June 1, 2012

Western Ohio Region employees represented by UWUA Local #111 were provided with a 2% general wage increase effective July 1, 2012

Canton Warehouse employees represented by UWUA Local #116 were provided with a 2% general wage increase effective July 1, 2012

Canton Region employees represented by UWUA Local #116 were provided with a 2% general wage increase effective July 1, 2012

Cook Coal Terminal employees represented by UMWA Local #2463 were provided with a 3.7% general wage increase extension through 2013

Gavin Plant employees represented by UWUA Local #296 were provided with a 2% general wage increase effective October 1, 2012

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

10. None

11. Reserved

12. Not Used

13. Nicholas K. Adkins elected as Chairman of the Board effective January 1, 2012

David M. Feinberg elected as Director and Secretary effective January 1, 2012

Mark C. McCullough elected as Director effective January 1, 2012

Scott N. Smith elected as Vice President effective January 26, 2012

Anne M. Vogel resigned as Assistant Secretary effective March 13, 2012

Joseph Hamrock resigned as President and Chief Operating Officer effective April 30, 2012

Pablo A. Vegas elected as President and Chief Operating Officer effective May 1, 2012

Mark A. Peifer resigned as Vice President - Generation Assets effective May 22, 2012

Barbara D. Radous resigned as Director and Vice President effective December 31, 2012

Charles E. Zebula resigned as Treasurer effective December 31, 2012

14. Proprietary capital ratio exceeds 30%

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	15,808,576,772	15,467,009,111
3	Construction Work in Progress (107)	200-201	354,496,915	354,465,481
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		16,163,073,687	15,821,474,592
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	6,670,266,900	6,098,377,155
6	Net Utility Plant (Enter Total of line 4 less 5)		9,492,806,787	9,723,097,437
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		9,492,806,787	9,723,097,437
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		27,287,566	26,902,625
19	(Less) Accum. Prov. for Depr. and Amort. (122)		10,826,797	10,839,308
20	Investments in Associated Companies (123)		430,000	430,000
21	Investment in Subsidiary Companies (123.1)	224-225	-1,804,458	-1,834,676
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	12,759,081	19,107,019
24	Other Investments (124)		120,140,432	118,505,770
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		0	0
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		48,001,526	53,578,159
31	Long-Term Portion of Derivative Assets – Hedges (176)		286,576	35,356
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		196,273,926	205,884,945
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		3,640,465	2,095,486
36	Special Deposits (132-134)		13,619,986	23,159,947
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		160,797,024	144,078,351
41	Other Accounts Receivable (143)		9,356,468	11,694,341
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		5,582,752	3,571,211
43	Notes Receivable from Associated Companies (145)		106,292,693	209,222,706
44	Accounts Receivable from Assoc. Companies (146)		170,651,273	155,961,433
45	Fuel Stock (151)	227	315,658,014	252,654,805
46	Fuel Stock Expenses Undistributed (152)	227	13,182,324	10,230,746
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	160,826,749	172,582,158
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	34,328,433	49,819,987

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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		12,759,081	19,107,019
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)		17,727,643	22,771,853
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		532	6,220,442
60	Rents Receivable (172)		2,396,749	2,354,076
61	Accrued Utility Revenues (173)		57,886,858	19,011,672
62	Miscellaneous Current and Accrued Assets (174)		4,331,981	4,461,038
63	Derivative Instrument Assets (175)		92,184,897	107,322,185
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		48,001,526	53,578,159
65	Derivative Instrument Assets - Hedges (176)		416,113	583,909
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		286,576	35,356
67	Total Current and Accrued Assets (Lines 34 through 66)		1,096,668,267	1,117,933,390
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		14,837,869	18,103,943
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	1,409,395,872	1,357,975,634
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,789,166	1,972,199
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	258,247,301	256,879,178
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)		13,215,480	14,551,607
82	Accumulated Deferred Income Taxes (190)	234	497,598,964	565,661,913
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,195,084,652	2,215,144,474
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		12,980,833,632	13,262,060,246

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2012/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	321,201,454	321,201,454
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	1,707,589,825	1,707,589,825
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	2,623,929,127	2,580,395,020
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	2,204,800	2,204,800
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)	-165,724,552	-197,721,635
16	Total Proprietary Capital (lines 2 through 15)		4,489,200,654	4,413,669,464
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
19	(Less) Reaquired Bonds (222)	256-257	462,500,000	418,000,000
20	Advances from Associated Companies (223)	256-257	200,000,000	200,000,000
21	Other Long-Term Debt (224)	256-257	4,130,325,000	4,280,325,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		7,384,697	8,177,158
24	Total Long-Term Debt (lines 18 through 23)		3,860,440,303	4,054,147,842
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		36,380,966	40,152,075
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		624,941	601,600
29	Accumulated Provision for Pensions and Benefits (228.3)		152,059,545	308,743,140
30	Accumulated Miscellaneous Operating Provisions (228.4)		5,459,665	30,444,899
31	Accumulated Provision for Rate Refunds (229)		22,577,000	20,000,000
32	Long-Term Portion of Derivative Instrument Liabilities		25,384,811	17,502,503
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		580,515	387,068
34	Asset Retirement Obligations (230)		265,026,210	237,119,843
35	Total Other Noncurrent Liabilities (lines 26 through 34)		508,093,653	654,951,128
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		276,205,657	293,642,232
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		154,247,266	186,735,942
41	Customer Deposits (235)		50,964,245	55,784,949
42	Taxes Accrued (236)	262-263	448,942,948	437,248,507
43	Interest Accrued (237)		64,279,794	68,187,886
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2012/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)		277,115	2,291,821
48	Miscellaneous Current and Accrued Liabilities (242)		130,325,753	117,256,555
49	Obligations Under Capital Leases-Current (243)		14,707,005	14,095,873
50	Derivative Instrument Liabilities (244)		48,216,808	51,211,394
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		25,384,811	17,502,503
52	Derivative Instrument Liabilities - Hedges (245)		1,903,605	3,239,217
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		580,515	387,068
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,164,104,870	1,211,804,805
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		274,889	275,115
57	Accumulated Deferred Investment Tax Credits (255)	266-267	11,643,327	13,492,560
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	65,678,586	50,451,156
60	Other Regulatory Liabilities (254)	278	39,462,132	38,553,823
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	376,657,740	353,460,058
63	Accum. Deferred Income Taxes-Other Property (282)		1,867,120,302	1,781,887,359
64	Accum. Deferred Income Taxes-Other (283)		598,157,176	689,366,936
65	Total Deferred Credits (lines 56 through 64)		2,958,994,152	2,927,487,007
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		12,980,833,632	13,262,060,246

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	4,921,622,058	5,455,769,264		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,721,314,561	3,210,008,620		
5	Maintenance Expenses (402)	320-323	319,324,438	393,943,466		
6	Depreciation Expense (403)	336-337	459,584,807	484,298,323		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	12,055,617	8,849,303		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	24,200,887	22,975,714		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	12,696	12,696		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		15,728,448	29,239,772		
13	(Less) Regulatory Credits (407.4)		512,603			
14	Taxes Other Than Income Taxes (408.1)	262-263	404,969,760	398,494,481		
15	Income Taxes - Federal (409.1)	262-263	91,930,521	168,987,812		
16	- Other (409.1)	262-263	8,580,447	4,537,706		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	540,713,172	596,165,325		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	395,675,882	542,311,812		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,768,489	-2,093,303		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)			8,727,304		
22	(Less) Gains from Disposition of Allowances (411.8)		8,154,591	13,979,215		
23	Losses from Disposition of Allowances (411.9)		2,117,874	5,969,272		
24	Accretion Expense (411.10)		14,767,942	13,171,145		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		4,209,189,605	4,786,996,609		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		712,432,453	668,772,655		

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
4,921,622,058	5,455,769,264					2
						3
2,721,314,561	3,210,008,620					4
319,324,438	393,943,466					5
459,584,807	484,298,323					6
12,055,617	8,849,303					7
24,200,887	22,975,714					8
12,696	12,696					9
						10
						11
15,728,448	29,239,772					12
512,603						13
404,969,760	398,494,481					14
91,930,521	168,987,812					15
8,580,447	4,537,706					16
540,713,172	596,165,325					17
395,675,882	542,311,812					18
-1,768,489	-2,093,303					19
						20
	8,727,304					21
8,154,591	13,979,215					22
2,117,874	5,969,272					23
14,767,942	13,171,145					24
4,209,189,605	4,786,996,609					25
712,432,453	668,772,655					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)		712,432,453	668,772,655		
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)		49,122,115	41,556,402		
34	(Less) Expenses of Nonutility Operations (417.1)		49,660,842	41,635,082		
35	Nonoperating Rental Income (418)		595,942	706,828		
36	Equity in Earnings of Subsidiary Companies (418.1)	119		70,000		
37	Interest and Dividend Income (419)		3,499,402	7,043,815		
38	Allowance for Other Funds Used During Construction (419.1)		3,491,759	5,548,812		
39	Miscellaneous Nonoperating Income (421)		24,890,606	55,080,024		
40	Gain on Disposition of Property (421.1)		1,511,119	11,367,656		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		33,450,101	79,738,455		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		-258,848	217,428		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		4,372,607	12,359,721		
46	Life Insurance (426.2)					
47	Penalties (426.3)		52,209	3,389,293		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,687,777	3,823,366		
49	Other Deductions (426.5)		280,656,471	52,563,840		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		287,510,216	72,353,648		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	1,005,527	984,577		
53	Income Taxes-Federal (409.2)	262-263	1,023,944	-76,076,084		
54	Income Taxes-Other (409.2)	262-263	87,190	-2,297,265		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	22,101,985	172,026,654		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	122,394,298	104,757,181		
57	Investment Tax Credit Adj.-Net (411.5)		-80,744	-286,702		
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-98,256,396	-10,406,001		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-155,803,719	17,790,808		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		202,006,228	204,509,827		
63	Amort. of Debt Disc. and Expense (428)		3,978,647	4,329,899		
64	Amortization of Loss on Reaquired Debt (428.1)		1,336,128	1,338,011		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		11,071,815	10,512,117		
68	Other Interest Expense (431)		3,747,937	3,231,163		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		9,046,128	2,349,893		
70	Net Interest Charges (Total of lines 62 thru 69)		213,094,627	221,571,124		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		343,534,107	464,992,339		
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)		343,534,107	464,992,339		

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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		2,576,018,934	2,762,444,406
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Capital Stock Expense	210		(323,317)
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			(323,317)
16	Balance Transferred from Income (Account 433 less Account 418.1)		343,534,107	464,922,339
17	Appropriations of Retained Earnings (Acct. 436)			
18	Excess Earnings on Hydro Licensed Projects	215.1	-654,657	(353,926)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-654,657	(353,926)
23	Dividends Declared-Preferred Stock (Account 437)			
24	Perferred Stock Not Subject to Mandatory Redemption			
25	4.08% Series			(54,177)
26	4.20% Series			(87,872)
27	4.40% Series			(126,977)
28	4.50% Series			(401,542)
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			(670,568)
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock		-300,000,000	(650,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-300,000,000	(650,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,618,898,384	2,576,018,934
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		5,030,743	4,376,086
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		5,030,743	4,376,086
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,623,929,127	2,580,395,020
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		2,204,800	2,134,800
50	Equity in Earnings for Year (Credit) (Account 418.1)			70,000
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		2,204,800	2,204,800

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	343,534,107	464,992,339
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	495,854,007	516,136,036
5	Amortization of Regulatory Debits and Credits (Net)	15,215,845	29,239,772
6	Impairment of Long-Lived Assets	287,030,792	89,823,886
7	Carrying Costs	-16,941,933	-53,345,160
8	Deferred Income Taxes (Net)	44,744,977	121,122,986
9	Investment Tax Credit Adjustment (Net)	-1,849,233	-2,380,005
10	Net (Increase) Decrease in Receivables	-21,613,572	73,088,052
11	Net (Increase) Decrease in Inventory	-66,928,853	51,521,509
12	Net (Increase) Decrease in Allowances Inventory	15,491,554	25,322,120
13	Net Increase (Decrease) in Payables and Accrued Expenses	-30,346,942	12,870,137
14	Net (Increase) Decrease in Other Regulatory Assets	-96,646,358	-64,417,950
15	Net Increase (Decrease) in Other Regulatory Liabilities	-13,088,606	18,376,655
16	(Less) Allowance for Other Funds Used During Construction	3,491,759	5,548,812
17	(Less) Undistributed Earnings from Subsidiary Companies		70,000
18	Other (provide details in footnote):	-19,073,495	81,308,852
19	Pension Contributions to Qualified Plan Trust	-42,485,000	-127,481,000
20	Over/Under Recovered Fuel, Net	10,597,928	-727,950
21	Deferred Property Taxes	-3,848,589	-5,722,132
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	896,154,870	1,224,109,335
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-516,720,156	-459,600,015
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-4,515,702	-822,250
30	(Less) Allowance for Other Funds Used During Construction	-3,491,759	-5,548,812
31	Other (provide details in footnote):		
32			
33	Acquired Assets	-2,919,185	-2,220,199
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-520,663,284	-457,093,652
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	7,320,163	47,462,642
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)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	45	623
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	gridSmart Reimbursement Allocation	10,013,254	25,563,591
54	(Increase) Decrease in Other Special Deposits		3,450,132
55	Notes Receivable from Associated Companies	102,930,013	-58,982,177
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-400,399,809	-439,598,841
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		50,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Long Term Issuances Costs		-252,103
66	Net Increase in Short-Term Debt (c)		
67	Proceeds from Acquired Assets subject to Capital Lease	289,918	666,647
68	Amortization of Amended Coal Contract Deferred Revenues		-276,694
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	289,918	50,137,850
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-194,500,000	-165,000,000
74	Preferred Stock		-17,831,070
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		-670,568
81	Dividends on Common Stock	-300,000,000	-650,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-494,210,082	-783,363,788
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	1,544,979	1,146,706
87			
88	Cash and Cash Equivalents at Beginning of Period	2,095,486	948,780
89			
90	Cash and Cash Equivalents at End of period	3,640,465	2,095,486

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2012/Q4

FOOTNOTE DATA

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

	2012 Cash Flow Incr/(Decr)	2011 Cash Flow Incr/(Decr)
Utility Plant, Net	$ (22,794,477)	$ (23,766,011)
Property and Investments, Net	(881,926)	(116,365)
Margin Deposits	9,539,961	10,597,708
Mark-to-Market of Risk Management Contracts	12,142,703	(3,695,224)
Prepayments	17,530,235	18,548,401
Accrued Utility Revenues, Net	(38,875,185)	41,737,804
Miscellaneous Current and Accr Assets	(3,008,336)	6,042,937
Unamortized Debt Expense	3,266,074	4,071,236
Other Deferred Debits, Net	4,675,569	(12,763,439)
Other Comprehensive Income, Net	(1,690,918)	(614,881)
Unamortized Discount/Premium on Long-Term Debt	792,461	795,867
Accumulated Provisions - Misc	(20,532,736)	43,799,732
Current and Accrued Liabilities, Net	7,098,764	(34,539,182)
Other Deferred Credits, Net	13,664,316	31,210,269
Total	$ (19,073,495)	$ 81,308,852

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

	2012 Cash Flow Incr/(Decr)	2011 Cash Flow Incr/(Decr)
Sale of H-frame Structures to Kentucky Power Company	$ 326,276	$ -
Sale of Boiler Feedpump to AEP Lawrenceburg	345,510	-
Sale of Carrier Blades to Appalachain Power Company	281,558	-
Sale of Land to Cyprus Creek Land Company	-	16,922,657
Sale of Land to Umang V. & Tracy L. Nanda	2,002,691	-
Sale of M/V Mike Weisend Towboat to Mass Mutual Life Ins. Co.	-	16,373,933
Sale of meters & transformers to various associated companies	1,062,574	3,388,604
Sale of Rotors to Appalachain Power Company	1,061,996	-
Ssle of Scrap Materials to Aaron Equipment Company	200,000	-
Sale of Scrap Metals to J.V. Metals LLC	563,000	100,760
Sale of Scrap Metals to TCI of Alabama LLC	391,572	-
Sale of Transformer (UTC 420786) to Southwestern Electric Power Co.	529,214	-
Sale of Transmission Assets to AEP Ohio Transco	555,772	8,723,440
Proceeds from acquired assets subject to operating lease	-	1,953,248
Total	$ 7,320,163	$ 47,462,642

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

NOTES TO FINANCIAL STATEMENTS

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

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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	/ /	2012/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

INDEX OF NOTES TO FINANCIAL STATEMENTS

Glossary of Term for Notes

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

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2012/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

GLOSSARY OF TERMS FOR NOTES

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., an electric utility holding company.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEPGenCo	AEP Generation Resources Inc., a nonregulated AEP subsidiary in the Generation and Marketing segment.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West Companies	PSO, SWEPCo, TCC and TNC.
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.
CRES	Competitive Retail Electric Service.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
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.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
ESP	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments.
FAC	Fuel Adjustment Clause.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
IEU	Industrial Energy Users-Ohio.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	/ /	2012/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
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.
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.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate transactions among members of the Interconnection Agreement.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NO_x	Nitrogen oxide.
OATT	Open Access Transmission Tariff.
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.
POLR	Provider of Last Resort revenues.
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.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SEET	Significantly Excessive Earnings Test.
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.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.

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1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, OPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 1,459,000 retail customers in the northwestern, central, eastern and southern sections of Ohio.

The Interconnection Agreement 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. Members of the Interconnection Agreement are compensated for their costs of energy delivered and charged for energy received. The capacity reserve relationship of the Interconnection Agreement members changes as generating assets are added, retired or sold and relative peak demand changes. The Interconnection Agreement 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. The addition of APCo's Dresden Plant in January 2012 and removal of OPCo's Sporn Plant, Unit 5 in September 2011 changed the capacity reserve relationship of the 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 2010. The new Transmission Agreement will be phased in for retail rates, added KGPCo and WPCo as parties to the agreement and changed the allocation method.

In 2007, OPCo and AEGCo entered into a 10-year unit power agreement for the entire output from the Lawrenceburg Plant with an option for an additional 2-year period. OPCo pays AEGCo for the capacity, depreciation, fuel, operation, maintenance and tax expenses. These payments are due regardless of whether the plant operates.

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 OPCo's behalf. OPCo 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 Interconnection Agreement and the SIA. OPCo 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.

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To minimize the credit requirements and operating constraints of 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.

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

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

OPCo is subject to regulation by the FERC under the Federal Power Act, the 2005 Public Utility Holding Company Act and the Energy Policy Act of 2005 and maintains accounts in accordance with the FERC and other regulatory guidelines. OPCo's rates are regulated by the FERC and the PUCO. The FERC also regulates affiliated transactions, including AEPSC intercompany service billings which are generally at cost. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires 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 PUCO also regulates certain intercompany transactions under various orders and affiliate statutes. Both the FERC and the PUCO 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. OPCo's wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when OPCo negotiates and files a cost-based contract with the FERC or the FERC determines that OPCo has "market power" in the region where the transaction occurs. OPCo 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 PUCO regulates all of the retail distribution operations and rates on a cost basis. The ESP rates in Ohio continue the process of aligning generation/power supply rates over time with market rates.

The FERC also regulates OPCo's wholesale transmission operations and rates. The FERC claims jurisdiction over retail transmission rates when retail rates are unbundled in connection with restructuring. OPCo's retail transmission rates in Ohio are unbundled and are based on formula rates included in the PJM OATT that are cost-based.

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. In October 2012, the AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and the AEP System Interim Allowance Agreement and approve a new Power Coordination Agreement among APCo, I&M and KPCo. A decision is expected from the FERC in mid-2013.

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Basis of Accounting

OPCo's accounting is subject to the requirements of the PUCO 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 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 reporting of acquired generating facilities on a gross basis rather than a net basis.
- The classification of noncurrent tax liabilities related to the accounting guidance for "Uncertainty in Income Taxes" as a current liability rather than a noncurrent liability.
- The classification of an accrued provision for potential refund as other noncurrent liability rather than a current liability.
- The classification of regulatory assets and liabilities related to the accounting guidance for "Accounting for Income Taxes" as separate assets and liabilities rather than as a single amount.
- The presentation of capital leased assets and their associated accumulated amortization as a single amount instead of as separate amounts.
- The classification of factored accounts receivable expense as a nonoperating expense instead of as an operating expense.
- The classification of certain nonoperating revenues as miscellaneous nonoperating income instead of as operating revenue.
- The classification of certain nonoperating expenses as miscellaneous nonoperating expense instead of as operating expense.
- The separate classification of income tax expense for operating and nonoperating activities instead of as a single income tax expense.
- The classification of a capital reserve associated with gridSMART® demonstration program as other deferred credits instead of property, plant and equipment – electric distribution.
- 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 accumulated depreciation associated with the acquisition of JMG as miscellaneous paid-in capital and accumulated deferred income taxes rather than as accumulated depreciation.
- The classification of unamortized loss on reacquired debt in deferred debits rather than in regulatory assets.

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- The classification of accumulated deferred investment tax credits in deferred credits rather than in regulatory liabilities and deferred investment tax credits.
- The classification of impaired plant in service in accumulated provision for depreciation, amortization and depletion rather than in property, plant and equipment – electric generation.
- The classification of certain other assets and liabilities as current instead of noncurrent.
- The classification of certain other assets and liabilities as noncurrent instead of current.

Accounting for the Effects of Cost-Based Regulation

As a rate-regulated electric public utility company, OPCo'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," OPCo records regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates. Due to the passage of legislation requiring restructuring and a transition to customer choice and market-based rates, OPCo applies "Regulated Operations" accounting treatment only to specifically approved portions of its generation business consisting of fuel and capacity costs.

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

	2012	2011
For the Years Ended December 31,	**(in thousands)**	
Cash was Paid for:		
Interest (Net of Capitalized Amounts)	$ 212,770	$ 226,712
Income Taxes (Net of Refunds)	69,160	80,098
Noncash Acquisitions Under Capital Leases	8,598	5,766
As of December 31,		
Government Grants Included in Other Accounts Receivable	660	1,383
Construction Expenditures Included in Current and Accrued Liabilities	84,320	61,428

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Special Deposits

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

Inventory

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

Accounts Receivable

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

Revenue is recognized from electric power sales when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, OPCo accrues and recognizes, as Accrued Utility Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, through purchase agreements with OPCo. See "Sale of Receivables – AEP Credit" section of Note 12 for additional information.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense related to receivables purchased from OPCo 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

OPCo does not have any significant customers that comprise 10% or more of its Operating Revenues as of December 31, 2012.

OPCo 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.

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Emission Allowances

OPCo records emission allowances at cost through December 31, 2014, including the annual SO_2 and NO_X emission allowance entitlements received at no cost from the Federal EPA. OPCo records allowances expected to be consumed subsequent to December 31, 2014 at the lower of cost or market when allowances are no longer included in the FAC due to energy auctions of SSO load. 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. The 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

Regulated

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

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets."

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.

Nonregulated

The generation operations of OPCo generally follow the policies of rate-regulated operations listed above but with the following exceptions. Property, plant and equipment of nonregulated operations are stated at fair value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for most nonregulated operations under the group composite method of depreciation. A gain or loss would be recorded if the retirement is not considered an interim routine replacement. Removal costs are charged to expense.

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Investment in Subsidiary Companies

OPCo has one wholly-owned subsidiary, Conesville Coal Preparation Company (CCPC). CCPC provides coal washing services for one of OPCo's generating stations. Coal washing services provided by CCPC are priced at cost plus an approved return on investment. Investment in the net assets of the wholly-owned subsidiary is carried at cost plus equity in its undistributed earnings since acquisition.

In addition, OPCo has a 50% interest in two jointly owned companies. The investments are included in Investment in Subsidiary Companies and were $735 thousand as of both December 31, 2012 and 2011. One company is a joint-facility company that operates the Cardinal Plant. The second company, Central Coal Company, which is owned with an affiliated company, is inactive. The expenses of the active joint-facility company, including compensation for the use of certain capital, are apportioned between the owners of the plant. OPCo's share of the costs is appropriately classified in operating expense accounts.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

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. For nonregulated operations, including generating assets owned by OPCo, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest."

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.

Fair Value Measurements of Assets and Liabilities

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

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

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the benefit plan 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 trust and Special Deposits are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities 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.

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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. OPCo's 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 PUCO's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the PUCO. On a routine basis, the PUCO reviews and/or audits OPCo's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a fuel cost disallowance becomes probable, OPCo adjusts its FAC deferrals and record provisions for estimated refunds to recognize these probable outcomes.

Changes in fuel costs (beginning in 2012 through the ESP related to non-auction standard service offer load served) are reflected in rates in a timely manner generally through the FAC. Changes in fuel costs, including purchased power in Ohio (beginning in 2009 through 2011) are reflected in rates through FAC phase-in plans. The FAC generally includes some sharing of off-system sales. None of the profits from off-system sales are given to customers through the FAC in Ohio.

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, OPCo records them as assets on the balance sheets. OPCo 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, OPCo writes off that regulatory asset as a charge against income.

Electricity Supply and Delivery Activities

OPCo recognizes revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. OPCo 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. Generally, these power sales and purchases are reported on a net basis as revenues. However, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are recorded gross as Operation Expenses. Other RTOs do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

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

In general, OPCo records expenses when purchased electricity is received and when expenses are incurred. For certain power purchase contracts that are derivatives and accounted for using MTM accounting, OPCo records these contracts on a net basis in revenues.

Energy Marketing and Risk Management Activities

AEPSC, on behalf of OPCo, 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. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. Certain energy marketing and risk management transactions are with RTOs.

OPCo recognizes revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. OPCo 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. OPCo includes realized gains and losses on wholesale marketing and risk management transactions in revenues on a net basis. Unrealized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM are included in revenues on a net basis.

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). OPCo 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, OPCo 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. The ineffective portion of the gain or loss is recognized in revenues or expense on the income statements immediately. See "Accounting for Cash Flow Hedging Strategies" section of Note 8.

Maintenance

OPCo expenses maintenance costs as incurred. If it becomes probable that OPCo will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues.

Income Taxes and Investment Tax Credits

OPCo 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.

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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.

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

Excise Taxes

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

Government Grants

For OPCo's gridSMART® demonstration program, OPCo is reimbursed by the Department of Energy for allowable costs incurred during the billing period. In addition, AEP built a cyber security operations center that will be used to enhance the capabilities for identifying cyber risks or threats, which was also partially funded by the gridSMART® demonstration grant for OPCo's incurred costs. These reimbursements result in the reduction of Operation Expenses and Maintenance Expenses or a reduction in Construction Work in Progress.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. OPCo's generating operations require that these costs be expensed upon reacquisition. OPCo reports gains and losses on the reacquisition of debt for operations that are not subject to cost-based rate regulation in Amortization of Debt Discount and Expense.

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.

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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. 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	40.0 %
Fixed Income	50.0 %
Other Investments	10.0 %

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

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

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

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

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and development risk classifications and some investments in Real Estate Investment Trusts (REITs), which are publicly traded real estate securities classified as Level 1.

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

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for cash collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the cash collateral is invested. The difference between the rebate owed to the borrower and the cash collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is providing modest incremental income with a limited increase in risk.

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

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

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.

OPCo Revised Depreciation Rates

Effective December 1, 2011, OPCo revised book depreciation rates for certain generating plants consistent with shortened depreciable lives for the generating units. This change in depreciable lives resulted in a $52 million increase in depreciation expense in 2012.

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In the fourth quarter of 2012, OPCo impaired the generating units discussed above (see Note 5). As a result of this impairment of the full book value of these assets, OPCo ceased depreciation on these generating units effective December 1, 2012.

2. RATE MATTERS

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

Ohio Electric Security Plan Filing

2009 – 2011 ESP

The PUCO issued an order in March 2009 that modified and approved the ESP which established rates at the start of the April 2009 billing cycle through 2011. OPCo collected the 2009 annualized revenue increase over the last nine months of 2009. The order also provided a phase-in FAC, which was authorized to be recovered through a non-bypassable surcharge over the period 2012 through 2018. The PUCO's March 2009 order was appealed to the Supreme Court of Ohio, which issued an opinion and remanded certain issues back to the PUCO.

In October 2011, the PUCO issued an order in the remand proceeding. As a result, OPCo ceased collection of POLR billings in November 2011 and recorded a write-off in 2011 related to POLR collections for the period June 2011 through October 2011. In February 2012, the Ohio Consumers' Counsel and the IEU filed appeals of that order with the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge, which, if ordered, could reduce OPCo's net deferred fuel costs up to the total balance. As of December 31, 2012, OPCo's net deferred fuel balance was $519 million, excluding unrecognized equity carrying costs. A decision from the Supreme Court of Ohio is pending.

In January 2011, the PUCO issued an order on the 2009 SEET filing, which resulted in a write-off in 2010 and a subsequent refund to customers during 2011. The IEU and the Ohio Energy Group filed appeals with the Supreme Court of Ohio challenging the PUCO's SEET decision. In December 2012, the Supreme Court of Ohio issued an order which rejected all of the intervenors' challenges and affirmed the PUCO decision.

The 2009 SEET order gave consideration for a future commitment to invest $20 million to support the development of a large solar farm. In January 2013, the PUCO found there was not a need for the large solar farm. The PUCO noted that OPCo remains obligated to spend $20 million on this solar project or another similar project by the end of 2013.

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In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. Subsequent testimony and legal briefs from intervenors recommended a refund of up to $62 million of 2010 earnings, which included off-system sales in the SEET calculation. In December 2011, the PUCO staff filed testimony that recommended a $23 million refund of 2010 earnings. OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO ordered SEET refund. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. The PUCO approved OPCo's request to file the 2011 SEET one month after the PUCO issues an order on the 2010 SEET. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo and in 2012 for OPCo.

Management is unable to predict the outcome of the unresolved litigation discussed above. If these proceedings result in adverse rulings, it could reduce future net income and cash flows and impact financial condition.

January 2012 – May 2016 ESP as Rejected by the PUCO

In December 2011, the PUCO approved an ESP modified stipulation which established a SSO pricing for generation. Various parties filed for rehearing with the PUCO requesting that the PUCO reconsider adoption of the modified stipulation. In February 2012, the PUCO issued an entry on rehearing which rejected the modified stipulation and ordered a return to the 2011 ESP rates. Those rates remained in effect until the new ESP was approved in August 2012. See the "June 2012 – May 2015 ESP Including Capacity Charge" section below.

As a result of the PUCO's rejection of the modified stipulation, OPCo reversed a $35 million obligation to contribute to the Partnership with Ohio and the Ohio Growth Fund and an $8 million regulatory asset for 2011 storm damage, both originally recorded in 2011.

As directed by the February 2012 order, OPCo filed revised tariffs with the PUCO to implement the provisions of the 2011 ESP. Included in the revised tariffs was the Phase-In Recovery Rider (PIRR) to recover deferred fuel costs as authorized under the 2009 – 2011 ESP order. In March 2012, the PUCO issued an order that directed OPCo to file new revised tariffs removing the PIRR and stated that its recovery would be addressed in a future proceeding. OPCo implemented the new revised tariffs in March 2012. In March 2012, OPCo resumed recording a weighted average cost of capital return on the deferred fuel balance in accordance with the 2009 - 2011 ESP order. OPCo also filed a request for rehearing of the March 2012 order relating to the PIRR, which the PUCO denied but provided that all of the substantive concerns and issues raised would be addressed in a separate PIRR docket.

In August 2012, the PUCO ordered implementation of PIRR rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. The August 2012 order was upheld on rehearing by the PUCO in October 2012. In November 2012, OPCo filed an appeal at the Supreme Court of Ohio claiming a long-term debt rate modified the previously adjudicated ESP order, which granted a weighted average cost of capital rate. The IEU and the Ohio Consumers' Counsel also filed appeals at the Supreme Court of Ohio in November 2012 arguing that the PUCO should have reduced the deferred fuel balance to reflect the prior "improper" collection of POLR revenues and reduced carrying costs due to an accumulated deferred income tax credit. See the "2009 – 2011 ESP" section above. These appeals could reduce OPCo's net deferred fuel balance up to the total balance, which would reduce future net income and cash flows. A decision from the Supreme Court of Ohio is pending.

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June 2012 – May 2015 ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that establishes base generation rates through May 2015, adopted a 12% earnings threshold for the SEET and allowed the continuation of the fuel adjustment clause. Further, the ESP established a non-bypassable Distribution Investment Rider effective September 2012 through May 2015 to recover, with certain caps, post-August 2010 distribution investment. The ESP also maintained recovery of several previous ESP riders and required OPCo to contribute $2 million per year during the ESP to the Ohio Growth Fund. In addition, the PUCO approved a storm damage recovery mechanism.

As part of the ESP decision, the PUCO ordered OPCo to conduct an energy-only auction for 10% of the SSO load with delivery beginning six months after the receipt of final orders in both the ESP and corporate separation cases and extending through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 50% of the SSO load with delivery beginning June 2014 through May 2015 and for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. OPCo will conduct energy and capacity auctions for its entire SSO load for delivery starting in June 2015.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The RPM price is approximately $20/MW day through May 2013. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio.

As part of the August 2012 PUCO ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is intended to provide approximately $500 million over the ESP period and will be collected from customers at $3.50/MWh through May 2014 and $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the deferred capacity costs. As of December 31, 2012, OPCo recorded $66 million of incurred deferred capacity costs, including debt carrying costs, in Regulatory Assets on the balance sheet. In August 2012, the IEU filed an action with the Supreme Court of Ohio stating, among other things, that OPCo's collection of its capacity costs is illegal. In September 2012, OPCo and the PUCO filed motions to dismiss the IEU's action. If OPCo is ultimately not permitted to fully collect its deferred capacity costs, it would reduce future net income and cash flows and impact financial condition. A decision from the Supreme Court of Ohio is pending.

In January 2013, the PUCO issued its Order on Rehearing for the ESP which generally upheld its August 2012 order including the implementation of the RSR. The PUCO clarified that a final reconciliation of revenues and costs would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket. If OPCo is ultimately not permitted to fully collect its ESP rates, including the RSR, it would reduce future net income and cash flows and impact financial condition.

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Corporate Separation

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo's generation assets including the transfer of OPCo's generation assets at net book value to AEPGenCo. AEPGenCo will also assume the associated generation liabilities. In December 2012, the PUCO granted the IEU and Ohio Consumers' Counsel requests for rehearing for the purpose of further consideration and those requests remain pending.

Also in October 2012, filings at the FERC were submitted related to corporate separation. See the "Corporate Separation and Termination of Interconnection Agreement" section below.

2011 Ohio Distribution Base Rate Case

In December 2011, the PUCO approved a stipulation which provided for no change in distribution rates and a new rider for a $15 million annual credit to residential ratepayers due principally to the inclusion of the rate base distribution investment in the Distribution Investment Rider (DIR) as approved in December 2011 by the modified stipulation in the ESP proceeding. However, when the February 2012 PUCO order rejected the ESP modified stipulation, collection of the DIR terminated. In August 2012, the PUCO approved a new DIR as part of the June 2012 – May 2015 ESP proceeding. The DIR is capped at $86 million in 2012, $104 million in 2013, $124 million in 2014 and $52 million for the period January through May 2015, for a total of $366 million.

Storm Damage Recovery Rider (SDRR)

In December 2012, OPCo submitted an application with the PUCO to establish initial SDRR rates. The SDRR seeks recovery of 2012 incremental storm distribution expenses over twelve months starting with the effective date of the SDRR as approved by the PUCO. If the PUCO extends recovery beyond twelve months and/or does not commence cost recovery by April 2013, OPCo requested approval of a weighted average cost of capital carrying charge, effective April 2013. As of December 31, 2012, OPCo recorded $62 million in Regulatory Assets on the balance sheet related to 2012 storm damage. If OPCo is not ultimately permitted to recover these storm costs, it would reduce future net income and cash flows and impact financial condition.

2009 Fuel Adjustment Clause Audit

The PUCO selected an outside consultant to conduct an audit of OPCo's FAC for 2009. The outside consultant provided its audit report to the PUCO. In January 2012, the PUCO ordered that the remaining $65 million in proceeds from a 2008 coal contract settlement agreement be applied against OPCo's under-recovered fuel balance. In April 2012, on rehearing, the PUCO ordered that the settlement credit only needed to reflect the Ohio retail jurisdictional share of the gain not already flowed through the FAC with carrying charges. OPCo recorded a $30 million net favorable adjustment on the statement of income in the second quarter of 2012. The January 2012 PUCO order also stated that a consultant should be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers. Management is unable to predict the outcome of any future consultant recommendation. If the PUCO ultimately determines that additional amounts should benefit ratepayers as a result of the consultant's review of the coal reserve valuation, it could reduce future net income and cash flows and impact financial condition.

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In August 2012, intervenors filed with the Supreme Court of Ohio claiming the settlement credit ordered by the PUCO should have reflected the remaining gain not already flowed through the FAC with carrying charges, which, if ordered, would be $35 million plus carrying charges. If the Supreme Court of Ohio ultimately determines that additional amounts should benefit ratepayers, it could reduce future net income and cash flows and impact financial condition.

2010 and 2011 Fuel Adjustment Clause Audits

The PUCO-selected outside consultant issued its 2010 and 2011 FAC audit reports which included a recommendation that the PUCO reexamine the carrying costs on the deferred FAC balance and determine whether the carrying costs on the balance should be net of accumulated income taxes. As of December 31, 2012, the amount of OPCo's carrying costs that could potentially be reduced due to the accumulated income tax issue is estimated to be approximately $36 million, including $19 million of unrecognized equity carrying costs. These amounts include the carrying costs exposure of the 2009 FAC audit, which has been appealed by an intervenor to the Supreme Court of Ohio. Decisions from the PUCO are pending. Management is unable to predict the outcome of these proceedings. If the PUCO orders result in a reduction to the FAC deferral, it would reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

OPCo and Ormet, a large aluminum company, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. This interim arrangement was approved by the PUCO and was effective from January 2009 through September 2009. In March 2009, the PUCO approved a FAC in the ESP filing and the FAC aspect of the ESP order was upheld by the Supreme Court of Ohio. The approval of the FAC as part of the ESP, together with the PUCO approval of the interim arrangement, provided the basis to record a regulatory asset for the difference between the approved market price and the rate paid by Ormet. Through September 2009, the last month of the interim arrangement, OPCo had $64 million of deferred FAC costs related to the interim arrangement, excluding $2 million of unrecognized equity carrying costs. In November 2009, OPCo requested that the PUCO approve recovery of the deferral under the interim agreement plus a weighted average cost of capital carrying charge. The deferral amount is included in OPCo's FAC phase-in deferral balance. In the 2009 – 2011 ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related regulatory asset and requested that the PUCO prevent OPCo from collecting the Ormet-related revenues in the future. The PUCO did not take any action on this request. The intervenors raised the issue again in response to OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement. This issue remains pending before the PUCO. If OPCo is not ultimately permitted to fully recover its requested deferrals under the interim arrangement, it would reduce future net income and cash flows and impact financial condition.

Special Rate Mechanism for Ormet

In October 2012, the PUCO issued an order approving a delayed payment plan for Ormet of its October and November 2012 power billings totaling $27 million to be paid in equal monthly installment over the period January 2014 to May 2015 without interest. In the event Ormet does not pay the $27 million, the PUCO permitted OPCo to recover the unpaid balance, up to $20 million, in the economic development rider. To the extent unpaid amounts exceed $20 million, it will reduce future net income and cash flows.

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Ohio IGCC Plant

In March 2005, OPCo filed an application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. As of December 31, 2012, OPCo has collected $24 million in pre-construction costs authorized in a June 2006 PUCO order. Intervenors have filed motions with the PUCO requesting all collected pre-construction costs be refunded to Ohio ratepayers with interest.

Management cannot predict the outcome of these proceedings concerning the Ohio IGCC plant or what effect, if any, these proceedings would have on future net income and cash flows. However, if OPCo is required to refund pre-construction costs collected, it could reduce future net income and cash flows and impact financial condition.

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. OPCo's portion of recognized gross SECA revenues is $92.1 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. In August 2010, the affected companies, including the AEP East Companies, filed a compliance filing with the FERC. The AEP East Companies provided reserves for net refunds for SECA settlements. The AEP East Companies settled with various parties prior to the FERC compliance filing and entered into additional settlements subsequent to the compliance filing being filed at the FERC. Based on the analysis of the May 2010 order, the compliance filing and recent settlements, management believes that the reserve is adequate to pay the refunds, including interest, and any remaining exposure beyond the reserve is immaterial.

Corporate Separation and Termination of Interconnection Agreement

In October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generation assets from its distribution and transmission operations. The filings requested approval to transfer at net book value approximately 9,200 MW of OPCo-owned generation assets to a new wholly-owned company, AEPGenCo. The AEP East Companies also requested FERC approval to transfer at net book value OPCo's current two-thirds ownership (867 MW) in Amos Plant, Unit 3 to APCo and transfer at net book value OPCo's Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each). Additionally, the AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement among APCo, I&M and KPCo. Intervenors have opposed several of these filings. The AEP East Companies have responded and continue to pursue approvals from the FERC. A decision from the FERC is expected in mid-2013.

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3. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2012	December 31, 2011	Remaining Recovery Period
Regulatory Assets:	(in thousands)		
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:			
Regulatory Assets Currently Earning a Return			
Economic Development Rider	$ 13,213	$ 12,572	
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	61,828	8,375	
Ormet Delayed Payment Arrangement	5,453	-	
Other Regulatory Assets Not Yet Being Recovered	30	-	
Total Regulatory Assets Not Yet Being Recovered	80,524	20,947	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Fuel Adjustment Clause	518,595	506,607	6 years
Deferred Asset Recovery Rider	152,039	173,274	6 years
Capacity Deferral	65,818	-	6 years
Transmission Cost Recovery Rider	49,390	28,404	3 years
RTO Formation/Integration Costs	6,594	7,836	7 years
Economic Development Rider	5,488	11,738	1 year
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	309,684	389,712	12 years
Income Tax Assets	192,332	193,004	21 years
Distribution Decoupling	16,198	-	2 years
Postemployment Benefits	7,658	8,669	5 years
Partnership with Ohio Contribution	2,405	3,400	3 years
Distribution Investment Rider	1,304	-	1 year
Unrealized Loss on Forward Commitments	810	9,930	1 year
Enhanced Service Reliability Plan	557	4,454	1 year
Total Regulatory Assets Being Recovered	1,328,872	1,337,028	
Total FERC Account 182.3 Regulatory Assets	$ 1,409,396	$ 1,357,975	

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	December 31, 2012	December 31, 2011	Remaining Refund Period
Regulatory Liabilities:	(in thousands)		
Regulatory liabilities not yet being paid:			
Regulatory Liabilities Currently Paying a Return			
IGCC Preconstruction Costs	$ 4,411	$ 4,196	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Not Yet Being Paid	216	216	
Total Regulatory Liabilities Not Yet Being Paid	4,627	4,412	
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Economic Development Rider	-	2,428	
Transmission Cost Recovery Rider	-	542	
Regulatory Liabilities Currently Not Paying a Return			
Over-recovered Fuel Costs	14,848	-	1 year
Peak Demand Reduction/Energy Efficiency	12,596	19,124	2 years
Income Tax Liabilities	1,647	2,022	21 years
Over-recovery of Costs Related to gridSMART®	3,501	7,504	2 years
Low Income Customers/Economic Recovery	2,243	2,521	3 years
Total Regulatory Liabilities Being Paid	34,835	34,141	
Total FERC Account 254 Regulatory Liabilities	$ 39,462	$ 38,553	

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

OPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, OPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements.

COMMITMENTS

Construction and Commitments

OPCo has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, OPCo contractually commits to third-party construction vendors for certain material purchases and other construction services. Management forecasts approximately $617 million of construction expenditures, excluding equity AFUDC and capitalized interest, for 2013.

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OPCo also purchases fuel, materials, supplies, services and property, plant and equipment under contract as part of its normal course of business. Certain supply contracts contain penalty provisions for early termination.

The following table summarizes the actual contractual commitments as of December 31, 2012:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 1,167,631	$ 2,012,580	$ 1,542,218	$ 1,368,019	$ 6,090,448
Energy and Capacity Purchase Contracts (b)	45,009	91,997	94,290	920,573	1,151,869
Construction Contracts for Capital Assets (c)	22,407	-	-	-	22,407
Total	$ 1,235,047	$ 2,104,577	$ 1,636,508	$ 2,288,592	$ 7,264,724

(a) Represents contractual commitments to purchase coal, natural gas 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

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

AEP has two credit facilities totaling $3.25 billion, under which up to $1.35 billion may be issued as letters of credit. In February 2013, AEP increased and extended the $1.5 billion credit facility due in June 2015 to $1.75 billion due in June 2016, extended the $1.75 billion credit facility due in July 2016 to July 2017 and issued a $1 billion interim credit facility due in May 2015 to fund certain OPCo maturities. As of December 31, 2012, OPCo's maximum future payment for letters of credit issued under the credit facilities was $2.1 million with a maturity of June 2013.

OPCo has $50 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $50.6 million. In February 2013, OPCo extended its bilateral letter of credit due in March 2013 to July 2014.

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Indemnifications and Other Guarantees

Contracts

OPCo 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, 2012, 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 power purchase and sale activity pursuant to the SIA.

Lease Obligations

OPCo leases certain equipment under master lease agreements. See "Master Lease Agreements" section of Note 11 for disclosure of lease residual value guarantees.

ENVIRONMENTAL CONTINGENCIES

Carbon Dioxide Public Nuisance Claims

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011. Plaintiffs refiled their complaint in federal district court. The court ordered all defendants to respond to the refiled complaints in October 2011. In March 2012, the court granted the defendants' motion for dismissal on several grounds, including the doctrine of collateral estoppel and the applicable statute of limitations. Plaintiffs appealed the decision to the Fifth Circuit Court of Appeals. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

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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. In September 2012, the Ninth Circuit Court of Appeals affirmed the trial court's decision, holding that the CAA displaced Kivalina's claims for damages. Plaintiffs' petition for rehearing by the full court was denied in November 2012, but the plaintiffs could seek further review in the U.S. Supreme Court. Management believes the action is without merit and will continue 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 and sludge. 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. OPCo 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. As of December 31, 2012, OPCo is named a Potentially Responsible Party (PRP) for three sites by the Federal EPA. There are three additional sites for which OPCo have received information requests which could lead to PRP designation. In those instances where OPCo has been named a PRP or defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

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.

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OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

OPCo maintains insurance coverage normal and customary for electric utilities, subject to various deductibles. Insurance coverage includes all risks of physical loss or damage to 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 OPCo. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

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. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could reduce future net income and cash flows and impact financial condition.

5. IMPAIRMENTS

2012

Beckjord Plant Unit 6, Conesville Plant Unit 3, Kammer Plant Units 1-3, Muskingum River Plant Units 1-4, Sporn Plant Units 2 and 4 and Picway Plant Unit 5

In October 2012, management filed applications with the FERC proposing to terminate the Interconnection Agreement and seeking to complete the corporate separation of OPCo's generation assets. Based on the intention to terminate the Interconnection Agreement and the FERC filing, management performed an evaluation of the recoverability of generation assets. As a result, in November 2012, management, using generating unit specific estimated future cash flows, concluded that OPCo had a material impairment of certain generation assets. Under a market-based value approach, using level 3 unobservable inputs, management determined that the fair value of these generating units was zero based on the lack of installed environmental control equipment and the nature and condition of these generating units. In the fourth quarter of 2012, OPCo recorded a pretax impairment of $287 million in Other Deductions related to Beckjord Plant Unit 6, Conesville Plant Unit 3, Kammer Plant Units 1-3, Muskingum River Plant Units 1-4, Sporn Plant Units 2 and 4 and Picway Plant Unit 5 generating units which includes $13 million of related material and supplies inventory.

2011

Muskingum River Plant Unit 5 FGD Project (MR5)

In September 2011, subsequent to the stipulation agreement filed with the PUCO, management determined that OPCo was not likely to complete the previously suspended MR5 project and that the project's preliminary engineering costs were no longer probable of being recovered. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $42 million in Operation Expenses.

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Sporn Plant Unit 5

In the third quarter of 2011, management decided to no longer offer the output of Sporn Unit 5 into the PJM market. Sporn Unit 5 is not expected to operate in the future, resulting in the removal of Sporn Unit 5 from the Interconnection Agreement. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $48 million in Operation Expenses.

6. BENEFIT PLANS

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

OPCO participates in an AEP sponsored qualified pension plan and two unfunded nonqualified pension plans. Substantially all employees are covered by the qualified plan or both the qualified and nonqualified pension plans. OPCO also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees.

OPCO recognizes the funded status associated with defined benefit pension and OPEB plans in its balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. OPCO 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. OPCO 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	**2012**	**2011**	**2012**	**2011**
Discount Rate	3.95 %	4.55 %	3.95 %	4.75 %
Rate of Compensation Increase	5.00 % (a)	5.00 % (a)	NA	NA

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

NA Not applicable.

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

For 2012, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 11.5% per year, with an average increase of 5%.

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	**2012**	**2011**	**2012**	**2011**
Discount Rate	4.55 %	5.05 %	4.75 %	5.25 %
Expected Return on Plan Assets	7.25 %	7.75 %	7.25 %	7.50 %
Rate of Compensation Increase	5.00 %	5.00 %	NA	NA

NA Not applicable.

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

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

Health Care Trend Rates	2012	2011
Initial	7.00 %	7.50 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2020	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	$ 5,129	$ (4,042)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	30,995	(23,603)

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Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. Management monitors the plans to control security diversification and ensure compliance with the investment policy. As of December 31, 2012, 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, 2012 and 2011

The following tables provide 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	
	2012	**2011**	**2012**	**2011**
Change in Benefit Obligation	(in thousands)			
Benefit Obligation as of January 1	$ 1,016,501	$ 979,781	$ 504,051	$ 491,176
Service Cost	10,979	10,207	8,437	7,537
Interest Cost	44,999	48,144	23,493	24,810
Actuarial Loss	63,464	42,841	40,853	49,596
Plan Amendment Prior Service Credit	-	-	(100,974)	(42,196)
Benefit Payments	(72,472)	(64,472)	(37,669)	(38,055)
Participant Contributions	-	-	8,508	8,786
Medicare Subsidy	-	-	2,501	2,397
Benefit Obligation as of December 31	$ 1,063,471	$ 1,016,501	$ 449,200	$ 504,051
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1	$ 922,283	$ 796,001	$ 310,571	$ 331,904
Actual Gain (Loss) on Plan Assets	118,014	63,208	64,820	(6,634)
Company Contributions	42,549	127,546	18,540	14,570
Participant Contributions	-	-	8,508	8,786
Benefit Payments	(72,472)	(64,472)	(37,669)	(38,055)
Fair Value of Plan Assets as of December 31	$ 1,010,374	$ 922,283	$ 364,770	$ 310,571
Underfunded Status as of December 31	$ (53,097)	$ (94,218)	$ (84,430)	$ (193,480)

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Amounts Recognized on the Balance Sheets as of December 31, 2012 and 2011

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2012	2011	2012	2011
	(in thousands)			
Miscellaneous Current and Accrued Liabilities - Short-term Benefit Liability	$ (64)	$ (62)	$ (582)	$ (508)
Accumulated Provision for Pensions and Benefits - Long-term Benefit Liability	(53,033)	(94,156)	(83,848)	(192,972)
Underfunded Status	$ (53,097)	$ (94,218)	$ (84,430)	$ (193,480)

Amounts Included in AOCI and Regulatory Assets as of December 31, 2012 and 2011

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2012	2011	2012	2011
Components	(in thousands)			
Net Actuarial Loss	$ 498,833	$ 515,569	$ 208,777	$ 224,122
Prior Service Cost (Credit)	1,278	2,019	(141,685)	(44,569)
Transition Obligation	-	-	-	74
Recorded as				
Regulatory Assets	$ 289,931	$ 305,240	$ 19,754	$ 84,472
Deferred Income Taxes	73,563	74,322	16,568	33,304
Net of Tax AOCI	136,617	138,026	30,770	61,851

Components of the change in amounts included in AOCI and regulatory assets during the years ended December 31, 2012 and 2011 are as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2012	2011	2012	2011
Components	(in thousands)			
Actuarial Loss During the Year	$ 13,572	$ 44,830	$ (2,119)	$ 80,022
Prior Service Credit	-	-	(100,974)	(42,196)
Amortization of Actuarial Loss	(30,308)	(24,721)	(13,226)	(6,933)
Amortization of Prior Service Credit (Cost)	(741)	(1,471)	3,858	212
Amortization of Transition Obligation	-	-	(74)	(106)
Change for the Year	$ (17,477)	$ 18,638	$ (112,535)	$ 30,999

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Pension and Other Postretirement Plans' Assets

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

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 281,456	$ -	$ -	$ -	$ 281,456	27.9 %
International	106,889	-	-	-	106,889	10.5 %
Real Estate Investment Trusts	19,484	-	-	-	19,484	1.9 %
Common Collective Trust - International	-	934	-	-	934	0.1 %
Subtotal - Equities	407,829	934	-	-	408,763	40.4 %
Fixed Income:						
Common Collective Trust - Debt	-	6,826	-	-	6,826	0.7 %
United States Government and Agency Securities	-	153,908	-	-	153,908	15.2 %
Corporate Debt	-	265,747	-	-	265,747	26.3 %
Foreign Debt	-	42,737	-	-	42,737	4.2 %
State and Local Government	-	9,462	-	-	9,462	0.9 %
Other - Asset Backed	-	7,663	-	-	7,663	0.8 %
Subtotal - Fixed Income	-	486,343	-	-	486,343	48.1 %
Real Estate	-	-	47,243	-	47,243	4.7 %
Alternative Investments	-	-	42,082	-	42,082	4.2 %
Securities Lending	-	17,284	-	-	17,284	1.7 %
Securities Lending Collateral (a)	-	-	-	(19,547)	(19,547)	(1.9)%
Cash and Cash Equivalents	-	27,058	-	-	27,058	2.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	1,148	1,148	0.1 %
Total	$ 407,829	$ 531,619	$ 89,325	$ (18,399)	$ 1,010,374	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.

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

	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2012	$ 1,366	$ 35,010	$ 34,369	$ 70,745
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	6,471	2,203	8,674
Relating to Assets Sold During the Period	(481)	-	1,068	587
Purchases and Sales	(885)	5,762	4,442	9,319
Transfers into Level 3	-	-	-	-
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2012	$ -	$ 47,243	$ 42,082	$ 89,325

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

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 98,171	$ -	$ -	$ -	$ 98,171	26.9 %
International	117,374	-	-	-	117,374	32.2 %
Subtotal - Equities	215,545	-	-	-	215,545	59.1 %
Fixed Income:						
Common Collective Trust - Debt	-	16,876	-	-	16,876	4.6 %
United States Government and Agency Securities	-	19,122	-	-	19,122	5.2 %
Corporate Debt	-	36,015	-	-	36,015	9.9 %
Foreign Debt	-	6,088	-	-	6,088	1.7 %
State and Local Government	-	1,693	-	-	1,693	0.5 %
Other - Asset Backed	-	2,286	-	-	2,286	0.6 %
Subtotal - Fixed Income	-	82,080	-	-	82,080	22.5 %
Trust Owned Life Insurance:						
International Equities	-	11,988	-	-	11,988	3.3 %
United States Bonds	-	37,821	-	-	37,821	10.3 %
Cash and Cash Equivalents	14,438	2,653	-	-	17,091	4.7 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	245	245	0.1 %
Total	$ 229,983	$ 134,542	$ -	$ 245	$ 364,770	100.0 %

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

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

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 311,798	$ -	$ -	$ -	$ 311,798	33.8 %
International	85,486	-	-	-	85,486	9.3 %
Real Estate Investment Trusts	22,290	-	-	-	22,290	2.4 %
Common Collective Trust - International	-	27,532	-	-	27,532	3.0 %
Subtotal - Equities	419,574	27,532	-	-	447,106	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	5,628	-	-	5,628	0.6 %
United States Government and Agency Securities	-	121,260	-	-	121,260	13.2 %
Corporate Debt	-	211,046	1,366	-	212,412	23.0 %
Foreign Debt	-	40,865	-	-	40,865	4.4 %
State and Local Government	-	10,300	-	-	10,300	1.1 %
Other - Asset Backed	-	5,573	-	-	5,573	0.6 %
Subtotal - Fixed Income	-	394,672	1,366	-	396,038	42.9 %
Real Estate	-	-	35,010	-	35,010	3.8 %
Alternative Investments	-	-	34,369	-	34,369	3.7 %
Securities Lending	-	46,034	-	-	46,034	5.0 %
Securities Lending Collateral (a)	-	-	-	(50,538)	(50,538)	(5.5)%
Cash and Cash Equivalents	-	19,886	-	-	19,886	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(5,622)	(5,622)	(0.6)%
Total	$ 419,574	$ 488,124	$ 70,745	$ (56,160)	$ 922,283	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.

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

	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2011	$ -	$ 17,168	$ 26,822	$ 43,990
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	4,966	2,160	7,126
Relating to Assets Sold During the Period	-	-	742	742
Purchases and Sales	-	12,876	4,645	17,521
Transfers into Level 3	1,366	-	-	1,366
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2011	$ 1,366	$ 35,010	$ 34,369	$ 70,745

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

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 76,610	$ -	$ -	$ -	$ 76,610	24.7 %
International	83,792	-	-	-	83,792	27.0 %
Common Collective Trust - Global	-	21,845	-	-	21,845	7.0 %
Subtotal - Equities	160,402	21,845	-	-	182,247	58.7 %
Fixed Income:						
Common Collective Trust - Debt	-	15,248	-	-	15,248	4.9 %
United States Government and Agency Securities	-	17,797	-	-	17,797	5.7 %
Corporate Debt	-	33,516	-	-	33,516	10.8 %
Foreign Debt	-	7,105	-	-	7,105	2.3 %
State and Local Government	-	1,853	-	-	1,853	0.6 %
Other - Asset Backed	-	422	-	-	422	0.1 %
Subtotal - Fixed Income	-	75,941	-	-	75,941	24.4 %
Trust Owned Life Insurance:						
International Equities	-	10,183	-	-	10,183	3.3 %
United States Bonds	-	34,769	-	-	34,769	11.2 %
Cash and Cash Equivalents	3,703	5,159	-	-	8,862	2.9 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	(1,431)	(1,431)	(0.5)%
Total	$ 164,105	$ 147,897	$ -	$ (1,431)	$ 310,571	100.0 %

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

Determination of Pension Expense

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

Accumulated Benefit Obligation	December 31, 2012	December 31, 2011
	(in thousands)	
Qualified Pension Plan	$ 1,044,129	$ 1,001,290
Nonqualified Pension Plans	796	821
Total	$ 1,044,925	$ 1,002,111

For the underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets of these plans as of December 31, 2012 and 2011 were as follows:

	December 31, 2012	December 31, 2011
	(in thousands)	
Projected Benefit Obligation	$ 1,063,471	$ 1,016,501
Accumulated Benefit Obligation	$ 1,044,925	$ 1,002,111
Fair Value of Plan Assets	1,010,374	922,283
Underfunded Accumulated Benefit Obligation	$ (34,551)	$ (79,828)

Estimated Future Benefit Payments and Contributions

OPCO expects contributions and payments for the pension plans of $9 million during 2013. For the pension plans, this amount includes the payment of unfunded nonqualified benefits plus contributions to the qualified trust fund of at least the minimum amount required by the Employee Retirement Income Security Act. For the qualified pension plan, OPCo may also make additional discretionary contributions to maintain the funded status of the plan.

The table below reflects the total benefits expected to be paid from the plan or from OPCO's assets. The payments include the participants' contributions to the plan for their share of the cost. In November 2012, changes to the retiree medical coverage were announced. Effective for retirements after December 2012, contributions to retiree medical coverage will be capped reducing exposure to future medical cost inflation. Effective for employees hired after December 2013, retiree medical coverage will not be provided. In December 2011, the prescription drug plan was amended for certain participants. The impact of the changes is reflected in the Benefit Plan Obligation table as plan amendments. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for pension benefits and OPEB are as follows:

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	Estimated Payments	
	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
2013	$ 72,170	$ 34,025
2014	73,466	34,942
2015	73,636	36,173
2016	75,047	37,811
2017	75,280	38,916
Years 2018 to 2022, in Total	369,388	220,020

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost for the years ended December 31, 2012 and 2011:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2012	2011	2012	2011
	(in thousands)			
Service Cost	$ 10,979	$ 10,207	$ 8,437	$ 7,537
Interest Cost	44,999	48,144	23,493	24,810
Expected Return on Plan Assets	(68,121)	(65,198)	(22,459)	(24,415)
Amortization of Transition Obligation	-	-	74	106
Amortization of Prior Service Cost (Credit)	741	1,471	(3,858)	(212)
Amortization of Net Actuarial Loss	30,308	24,721	13,226	6,933
Net Periodic Benefit Cost	18,906	19,345	18,913	14,759
Capitalized Portion	(7,033)	(6,945)	(7,036)	(5,298)
Net Periodic Benefit Cost Recognized as Expense	$ 11,873	$ 12,400	$ 11,877	$ 9,461

Estimated amounts expected to be amortized to net periodic benefit costs and the impact on the balance sheet during 2013 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
Net Actuarial Loss	$ 35,977	$ 15,621
Prior Service Cost (Credit)	282	(12,871)
Total Estimated 2013 Amortization	$ 36,259	$ 2,750
Expected to be Recorded as		
Regulatory Asset	$ 19,387	$ 599
Deferred Income Taxes	5,905	753
Net of Tax AOCI	10,967	1,398
Total	$ 36,259	$ 2,750

American Electric Power System Retirement Savings Plan

OPCO participates in an AEP sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions to the retirement savings plan for the years ended December 31, 2012 and 2011 was $10.8 million and $10.1 million, respectively.

7. BUSINESS SEGMENTS

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

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

OPCo 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 OPCo due to changes in the underlying market prices or rates. AEPSC, on behalf of OPCo, manages these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

AEPSC, on behalf of OPCo, 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 OPCo, 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 OPCo, 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 OPCo's outstanding derivative contracts as of December 31, 2012 and 2011:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume December 31, 2012	Volume December 31, 2011	Unit of Measure
	(in thousands)		
Commodity:			
Power	132,188	229,468	MWhs
Coal	3,033	8,337	Tons
Natural Gas	14,163	10,728	MMBtus
Heating Oil and Gasoline	1,260	1,254	Gallons
Interest Rate	$ 33,934	$ 42,093	USD

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Fair Value Hedging Strategies

AEPSC, on behalf of OPCo, 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 OPCo, 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. OPCo does not hedge all commodity price risk.

OPCo's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of OPCo, 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." OPCo does not hedge all fuel price risk.

AEPSC, on behalf of OPCo, 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 OPCo, 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. OPCo does not hedge all interest rate exposure.

At times, OPCo 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 OPCo, 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. OPCo 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.

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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," OPCo 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, OPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2012 and 2011 balance sheets, OPCo 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,
(in thousands)

2012		**2011**	
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**
$ 1,774	$ 15,500	$ 5,810	$ 39,183

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The following tables represent the gross fair value of derivative activity on the balance sheets as of December 31, 2012 and 2011:

Fair Value of Derivative Instruments
December 31, 2012

	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (d)
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
			(in thousands)			
Derivative Instrument Assets	$ 268,087	$ -	$ -	$ 268,087	$ (175,902)	$ 92,185
Long-Term Portion of Derivative Instrument Assets	85,023	-	-	85,023	(37,022)	48,001
Derivative Instrument Assets – Hedges	-	767	-	767	(351)	416
Long-Term Portion of Derivative Instrument Assets – Hedges	-	303	-	303	(16)	287
Derivative Instrument Liabilities	237,845	-	-	237,845	(189,628)	48,217
Long-Term Portion of Derivative Instrument Liabilities	66,448	-	-	66,448	(41,063)	25,385
Derivative Instrument Liabilities – Hedges	-	2,254	-	2,254	(351)	1,903
Long-Term Portion of Derivative Instrument Liabilities – Hedges	-	596	-	596	(16)	580

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Fair Value of Derivative Instruments
December 31, 2011

	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (c)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (d)
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
			(in thousands)			
Derivative Instrument Assets	$ 462,423	$ -	$ -	$ 462,423	$ (355,100)	$ 107,323
Long-Term Portion of Derivative Instrument Assets	136,519	-	-	136,519	(82,940)	53,579
Derivative Instrument Assets – Hedges	-	1,531	-	1,531	(947)	584
Long-Term Portion of Derivative Instrument Assets – Hedges	-	122	-	122	(87)	35
Derivative Instrument Liabilities	441,761	-	-	441,761	(390,549)	51,212
Long-Term Portion of Derivative Instrument Liabilities	112,454	-	-	112,454	(94,951)	17,503
Derivative Instrument Liabilities – Hedges	-	4,186	-	4,186	(947)	3,239
Long-Term Portion of Derivative Instrument Liabilities – Hedges	-	474	-	474	(87)	387

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) Amounts primarily 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.
(d) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The table below presents the activity of derivative risk management contracts for the years ended December 31, 2012 and 2011:

Amount of Gain (Loss) Recognized on Risk Management Contracts Years Ended December 31, 2012 and 2011

Location of Gain (Loss)	2012	2011
	(in thousands)	
Operating Revenues	$ 11,978	$ 27,488
Operation Expenses	-	(2)
Regulatory Assets (a)	(14,104)	(17,928)
Regulatory Liabilities (a)	-	(105)
Total Gain (Loss) on Risk Management Contracts	$ (2,126)	$ 9,453

(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.

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.

OPCo records realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest on Long-Term Debt on the statements of income. During 2012 and 2011, OPCo did not employ any fair value hedging strategies.

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Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows attributable to a particular risk), OPCo 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. OPCo recognizes any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal and natural gas designated as cash flow hedges are included in Operating Revenues or Operation Expenses on the statements of income or in regulatory assets or regulatory liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During 2012 and 2011, OPCo designated power, coal and natural gas derivatives as cash flow hedges.

OPCo reclassifies gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income on the balance sheets into Operation Expenses, Maintenance Expenses or Depreciation Expense, as it relates to capital projects, on the statements of income. During 2012 and 2011, OPCo designated heating oil and gasoline derivatives as cash flow hedges.

OPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income on the balance sheets into Interest on Long-Term Debt on the statements of income in those periods in which hedged interest payments occur.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income on the balance sheets into Depreciation Expense on the statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships.

During 2012 and 2011, hedge ineffectiveness was immaterial or nonexistent for all of the hedge strategies disclosed above.

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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, 2012 and 2011. 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, 2012

	Commodity Contracts	Interest Rate and Foreign Currency Contracts	Total Contracts
		(in thousands)	
Balance in AOCI as of December 31, 2011	$ (1,748)	$ 9,454	$ 7,706
Changes in Fair Value Recognized in AOCI	(2,002)	-	(2,002)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Operating Revenues	(109)	-	(109)
Operation Expenses	2,967	-	2,967
Maintenance Expenses	(5)	-	(5)
Depreciation Expense	-	4	4
Interest on Long-Term Debt	-	(1,363)	(1,363)
Utility Plant	(15)	-	(15)
Regulatory Assets (a)	-	-	-
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2012	$ (912)	$ 8,095	$ 7,183

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	$ (364)	$ 10,813	$ 10,449
Changes in Fair Value Recognized in AOCI	(2,748)	-	(2,748)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Operating Revenues	1,457	-	1,457
Operation Expenses	265	-	265
Maintenance Expenses	(141)	-	(141)
Depreciation Expense	-	4	4
Interest on Long-Term Debt	-	(1,363)	(1,363)
Utility Plant	(217)	-	(217)
Regulatory Assets (a)	-	-	-
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2011	$ (1,748)	$ 9,454	$ 7,706

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

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Cash flow hedges included in Accumulated Other Comprehensive Income on the balance sheets as of December 31, 2012 and 2011 were:

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

	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Hedging Assets (a)	$ 416	$ -	$ 416
Hedging Liabilities (a)	1,903	-	1,903
AOCI Gain (Loss) Net of Tax	(912)	8,095	7,183
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(720)	1,359	639

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

	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Hedging Assets (a)	$ 584	$ -	$ 584
Hedging Liabilities (a)	3,239	-	3,239
AOCI Gain (Loss) Net of Tax	(1,748)	9,454	7,706
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(1,518)	1,359	(159)

(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, 2012, the maximum length of time that OPCo is hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") exposure to variability in future cash flows to forecasted transactions is 17 months).

Credit Risk

AEPSC, on behalf of OPCo, 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 OPCo, 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.

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AEPSC, on behalf of OPCo, 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, OPCo 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. OPCo has not experienced a downgrade below investment grade. The following table represents: (a) OPCo's fair values of such derivative contracts, (b) the amount of collateral OPCo 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, 2012 and 2011:

	Liabilities for Derivative Contracts with Credit Downgrade Triggers	Amount of Collateral OPCo Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities
		(in thousands)	
December 31, 2012	$ 3,034	$ 5,198	$ 4,933
December 31, 2011	13,550	8,410	8,410

As of December 31, 2012 and 2011, OPCo was not required to post any collateral.

In addition, a majority of OPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by OPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering OPCo's contractual netting arrangements as of December 31, 2012 and 2011:

	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, 2012	$ 69,516	$ 2,561	$ 42,386
December 31, 2011	104,091	10,978	37,380

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9. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

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

The book values and fair values of Long-term Debt as of December 31, 2012 and 2011 are summarized in the following table:

December 31,			
2012		2011	
Book Value	Fair Value	Book Value	Fair Value
(in thousands)			
$ 3,860,440	$ 4,560,337	$ 4,054,148	$ 4,665,739

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, 2012 and 2011. 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.

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

	Level 1	Level 2	Level 3	Other	Total
			(in thousands)		
Assets:					
Special Deposits (a)	$ -	$ 26	$ -	$ 39	$ 65
Derivative Instrument Assets					
Risk Management Commodity Contracts (b) (c)	5,848	238,254	23,973	(175,890)	92,185
Derivative Instrument Assets – Hedges					
Cash Flow Hedges – Commodity (b)	-	688	-	(272)	416
Total Assets	$ 5,848	$ 238,968	$ 23,973	$ (176,123)	$ 92,666
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (b) (c)	$ 2,753	$ 226,536	$ 8,544	$ (189,616)	$ 48,217
Derivative Instrument Liabilities – Hedges					
Cash Flow Hedges – Commodity (b)	-	2,175	-	(272)	1,903
Total Liabilities	$ 2,753	$ 228,711	$ 8,544	$ (189,888)	$ 50,120

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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)		
Special Deposits (a)	$ 26	$ -	$ -	$ 22	$ 48
Derivative Instrument Assets					
Risk Management Commodity Contracts (b) (c)	6,339	421,249	34,425	(356,766)	105,247
De-designated Risk Management Contracts (d)	-	-	-	2,076	2,076
Total Derivative Instrument Assets	6,339	421,249	34,425	(354,690)	107,323
Derivative Instrument Assets – Hedges					
Cash Flow Hedges – Commodity (b)	-	1,483	-	(899)	584
Total Assets	$ 6,365	$ 422,732	$ 34,425	$ (355,567)	$ 107,955
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (b) (c)	$ 3,433	$ 406,259	$ 31,659	$ (390,139)	$ 51,212
Derivative Instrument Liabilities – Hedges					
Cash Flow Hedges – Commodity (b)	-	4,038	100	(899)	3,239
Total Liabilities	$ 3,433	$ 410,297	$ 31,759	$ (391,038)	$ 54,451

(a) Amounts in "Other" column primarily represent cash deposits with third parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.
(b) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(c) Substantially comprised of power contracts.
(d) 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.

There have been no transfers between Level 1 and Level 2 during the years ended December 31, 2012 and 2011.

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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, 2012	**Net Risk Management Assets (Liabilities)**
	(in thousands)
Balance as of December 31, 2011	$ 2,666
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(7,452)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	5,401
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	28
Purchases, Issuances and Settlements (c)	16,214
Transfers into Level 3 (d) (e)	1,909
Transfers out of Level 3 (e) (f)	(2,527)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(810)
Balance as of December 31, 2012	$ 15,429

Year Ended December 31, 2011	**Net Risk Management Assets (Liabilities)**
	(in thousands)
Balance as of December 31, 2010	$ 6,583
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(2,711)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	7,741
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(100)
Purchases, Issuances and Settlements (c)	1,858
Transfers into Level 3 (d) (e)	3,257
Transfers out of Level 3 (e) (f)	(4,032)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(9,930)
Balance as of December 31, 2011	$ 2,666

(a) Included in revenues on the statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Represents existing assets or liabilities that were previously categorized as Level 3.
(g) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory assets/liabilities.

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The following table quantifies the significant unobservable inputs used in developing the fair value of Level 3 positions as of December 31, 2012:

	Fair Value		Valuation	Significant	Forward Price Range	
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High
	(in thousands)					
Energy Contracts	$ 21,516	$ 5,510	Discounted Cash Flow	Forward Market Price	$ 9.40	$ 68.80
FTRs	2,457	3,034	Discounted Cash Flow	Forward Market Price	(3.21)	14.79
Total	$ 23,973	$ 8,544				

(a) Represents market prices in dollars per MWh.

10. INCOME TAXES

The details of OPCo's income taxes as reported are as follows:

	Years Ended December 31, 2012	2011
	(in thousands)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ 100,511	$ 173,525
Deferred	145,037	53,854
Deferred Investment Tax Credits	(1,768)	(2,093)
Total	243,780	225,286
Charged (Credited) to Nonoperating Income, Net:		
Current	1,111	(78,373)
Deferred	(100,292)	67,269
Deferred Investment Tax Credits	(81)	(287)
Total	(99,262)	(11,391)
Income Tax Expense	$ 144,518	$ 213,895

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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, 2012	2011
	(in thousands)	
Net Income	$ 343,534	$ 464,992
Income Tax Expense	144,518	213,895
Pretax Income	$ 488,052	$ 678,887
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 170,818	$ 237,610
Increase (Decrease) in Income Taxes resulting from the following items:		
Depreciation	5,239	6,368
Investment Tax Credits, Net	(1,849)	(2,380)
State and Local Income Taxes, Net	(18,291)	(3,222)
Parent Company Loss Benefit	(11,915)	(6,989)
Other	516	(17,492)
Income Tax Expense	$ 144,518	$ 213,895
Effective Income Tax Rate	29.6%	31.5%

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

	December 31, 2012	2011
	(in thousands)	
Deferred Tax Assets	$ 497,599	$ 565,662
Deferred Tax Liabilities	(2,841,935)	(2,824,714)
Net Deferred Tax Liabilities	$ (2,344,336)	$ (2,259,052)
Property Related Temporary Differences	$ (2,054,027)	$ (1,958,167)
Amounts Due from Customers for Future Federal Income Taxes	(59,291)	(59,699)
Deferred State Income Taxes	(90,358)	(98,774)
Deferred Income Taxes on Other Comprehensive Loss	86,263	103,476
Impairment Loss	100,459	-
Accrued Pensions	(43,397)	(30,543)
Regulatory Assets	(190,273)	(205,925)
Deferred Fuel and Purchased Power	(199,997)	(194,509)
Postretirement Benefits	47,204	71,546
All Other, Net	59,081	113,543
Net Deferred Tax Liabilities	$ (2,344,336)	$ (2,259,052)

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AEP System Tax Allocation Agreement

OPCo 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

OPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2009. OPCo 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 materially impact OPCo's net income, cash flows or financial condition. The Internal Revenue Service 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, OPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

OPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns. OPCo 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, OPCo and other AEP subsidiaries are no longer subject to state or local income tax examinations by tax authorities for years before 2008. In March 2012, AEP settled all outstanding franchise tax issues with the state of Ohio for the years 2000 through 2009. The settlements did not materially impact OPCo's net income, cash flows or financial condition.

Net Income Tax Operating Loss Carryforward

As of December 31, 2012, OPCo had a state net income tax operating loss carryforward of $313 million for West Virginia that expires in 2032. As a result, OPCo accrued deferred state and local income tax benefits in 2011 and 2012 and expects to realize the state and local cash flow benefits in future periods as there was insufficient capacity in prior periods to carry the net operating loss 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 2032.

Tax Credit Carryforward

The AEP System sustained consolidated federal net income tax operating losses in 2011 and 2009 along with lower federal taxable income, resulting in unused federal income tax credits. As of December 31, 2012, OPCo has federal tax credit carryforwards of $21.3 million. If these credits are not utilized, federal general business tax credits will expire in the years 2028 through 2031.

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OPCo 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

OPCo 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, 2012	2011
	(in thousands)	
Interest Expense	$ 266	$ 1,213
Interest Income	-	5,173
Reversal of Prior Period Interest Expense	504	4,019

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

	December 31, 2012	2011
	(in thousands)	
Accrual for Receipt of Interest	$ -	$ 869
Accrual for Payment of Interest and Penalties	451	1,513

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

	2012	2011
	(in thousands)	
Balance as of January 1,	$ 43,565	$ 68,655
Increase - Tax Positions Taken During a Prior Period	1,360	11,330
Decrease - Tax Positions Taken During a Prior Period	(13,582)	(20,299)
Increase - Tax Positions Taken During the Current Year	-	-
Decrease - Tax Positions Taken During the Current Year	-	-
Decrease - Settlements with Taxing Authorities	(20,291)	(6,935)
Decrease - Lapse of the Applicable Statute of Limitations	-	(9,186)
Balance as of December 31,	$ 11,052	$ 43,565

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 $674 thousand and $21.1 million for 2012 and 2011, respectively.

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Federal Tax Legislation

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. In November 2012, the effective date was moved to tax years beginning in 2014. Further, the notice stated that the U. S. Treasury Department anticipates that the final regulations will contain changes from the temporary regulations. Management will evaluate the impact of these regulations once they are issued.

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

State Tax Legislation

During the third quarter of 2012, the state of West Virginia achieved certain minimum levels of shortfall reserve funds. As a result, the West Virginia corporate income tax rate will be reduced from 7.75% to 7.0% in 2013. In addition, Michigan repealed its Business Tax regime in May 2011 and replaced it with a traditional corporate net income tax with a rate of 6%, effective January 1, 2012. The enacted provisions will not materially impact OPCo's net income, cash flows or financial condition.

11. LEASES

Leases of property, plant and equipment are for periods up to 60 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

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

	Years Ended December 31, 2012	2011
	(in thousands)	
Net Lease Expense on Operating Leases	$ 59,836	$ 59,971
Amortization of Capital Leases	10,905	12,891
Interest on Capital Leases	3,303	3,747
Total Lease Rental Costs	$ 74,044	$ 76,609

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

	December 31, 2012	December 31, 2011
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 39,080	$ 36,689
Other Property, Plant and Equipment	35,666	36,264
Total Property, Plant and Equipment	74,746	72,953
Accumulated Amortization	27,513	22,075
Net Property, Plant and Equipment Under Capital Leases	$ 47,233	$ 50,878
Obligations Under Capital Leases:		
Noncurrent	$ 36,381	$ 40,152
Current	14,707	14,096
Total Obligations Under Capital Leases	$ 51,088	$ 54,248

Future minimum lease payments consisted of the following as of December 31, 2012:

	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2013	$ 13,669	$ 58,968
2014	10,371	55,261
2015	7,383	52,287
2016	6,743	46,002
2017	6,322	42,678
Later Years	17,905	68,094
Total Future Minimum Lease Payments	62,393	$ 323,290
Less Estimated Interest Element	11,305	
Estimated Present Value of Future Minimum Lease Payments	$ 51,088	

Master Lease Agreements

OPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, OPCo is committed to pay the difference between the actual fair value and the residual value guarantee. As of December 31, 2012, 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 $4 million. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

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12. FINANCING ACTIVITIES

Preferred Stock

In December 2011, OPCo redeemed all of its outstanding preferred stock, resulting in a loss. The par value of preferred stock redeemed and the loss recorded was $16.6 million and $488 thousand, respectively. The numbers of shares redeemed for the year ended December 31, 2011 are as follows:

Series	Number of Shares Redeemed
4.08 %	14,495
4.20 %	22,824
4.40 %	31,482
4.50 %	97,357

Long-term Debt

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

The following details long-term debt outstanding as of December 31, 2012 and 2011:

Type of Debt	Maturity	Weighted Average Interest Rate as of December 31, 2012	Interest Rate Ranges as of December 31, 2012	Interest Rate Ranges as of December 31, 2011	Outstanding as of December 31, 2012	Outstanding as of December 31, 2011
					(in thousands)	
Senior Unsecured Notes	2012-2035	5.84%	4.85%-6.60%	0.955%-6.60%	$ 3,150,000	$ 3,300,000
Pollution Control Bonds (a)	2012-2038 (b)	3.72%	0.13%-5.80%	0.07%-5.80%	517,825	562,325
Notes Payable - Affiliated	2015	5.25%	5.25%	5.25%	200,000	200,000
Unamortized Discount, Net					(7,385)	(8,177)
Total Long-term Debt					$ 3,860,440	$ 4,054,148

(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.

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Long-term debt outstanding as of December 31, 2012 is payable as follows:

	(in thousands)
2013	$ 856,000
2014	403,580
2015	286,000
2016	350,000
2017	-
After 2017	1,972,245
Principal Amount	3,867,825
Unamortized Discount, Net	(7,385)
Total Long-term Debt Outstanding	$ 3,860,440

In February 2013, OPCo retired $250 million of 5.5% Senior Unsecured Notes due in 2013.

In March 2013, OPCo issued $200 million of variable rate intercompany debt from AEP due in 2015.

In March 2013, OPCo retired $250 million of 5.5% Senior Unsecured Notes due in 2013.

In March 2013, OPCo retired $50 million of variable rate Pollution Control Bonds due in 2014. The variable rate bonds were held by a trustee on behalf of OPCo.

As of December 31, 2012, trustees held, on behalf of OPCo, $463 million of its reacquired Pollution Control Bonds.

Dividend Restrictions

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

Federal Power Act

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

Additionally, the Federal Power Act creates a reserve on earnings attributable to hydroelectric generating plants. Because of its ownership of such plants, this reserve applies to OPCo.

None of these restrictions limit the ability of OPCo to pay dividends out of retained earnings.

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, OPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. As of December 31, 2012, none of OPCo's retained earnings have restrictions related to the payment of dividends to Parent.

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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 AEP's 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, 2012 and 2011 is included in Notes Receivable from Associated Companies on the balance sheets. OPCo's money pool activity and its corresponding authorized borrowing limits for the years ended December 31, 2012 and 2011 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 to Utility Money Pool as of December 31	Authorized Short-term Borrowing Limit
			(in thousands)			
2012	$ 126,975	$ 278,923	$ 47,820	$ 119,252	$ 106,293	$ 600,000
2011	46,761	443,223	31,365	223,169	209,223	600,000

Maximum, minimum and average interest rates for funds borrowed from and loaned to the Utility Money Pool for the years ended December 31, 2012 and 2011 are summarized in the following table:

Years Ended December 31,	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2012	0.48%	0.46%	0.56%	0.39%	0.47%	0.47%
2011	0.45%	0.44%	0.56%	0.06%	0.45%	0.35%

Interest expense related to the Utility Money Pool is included in Interest on Debt to Associated Companies. OPCo incurred interest expense for amounts borrowed from the Utility Money Pool of $572 thousand and $12 thousand for the years ended December 31, 2012 and 2011, respectively.

Interest income related to the Utility Money Pool is included in Interest and Dividend Income. OPCo earned interest income for amounts advanced to the Utility Money Pool of $1 million and $795 thousand for the years ended December 31, 2012 and 2011, respectively.

Credit Facilities

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

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Sale of Receivables – AEP Credit

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

In 2012, AEP Credit renewed its receivables securitization agreement. The agreement provides a commitment of $700 million from bank conduits to finance receivables from AEP Credit. A commitment of $385 million expires in June 2013 and the remaining commitment of $315 million expires in June 2015.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement as of December 31, 2012 and 2011 was $301 million and $347 million, respectively.

The fees paid to AEP Credit for customer accounts receivable sold were $20.3 million and $18.9 million for the years ended December 31, 2012 and 2011, respectively.

OPCo's proceeds on the sale of receivables to AEP Credit were $3 billion and $3.5 billion for the years ended December 31, 2012 and 2011, respectively.

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

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

Interconnection Agreement

OPCo, along with APCo, I&M, KPCo and AEPSC are parties to the Interconnection Agreement, which defines the sharing of costs and benefits associated with the respective 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, OPCo, along with APCo, I&M and KPCo 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.

In October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generating assets from its distribution and transmission operations. Additionally, the AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and to approve a new Power Coordination Agreement among APCo, I&M and KPCo. A decision from the FERC is expected in mid-2013. See "Corporate Separation and Termination of Interconnection Agreement" section of Note 2.

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Power, gas and risk management activities are conducted by AEPSC and profits and losses are allocated under the SIA to members of the Interconnection Agreement, 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. Revenues and costs arising from third party sales are generally shared based on the amount of energy PSO or SWEPCo contributes that is sold to third parties.

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 based on a statutory formula as Ohio transitions to the use of market rates for generation.

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

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Affiliated Revenues and Purchases

The following table shows the revenues derived from sales under the Interconnection Agreement, direct sales to affiliates, net transmission agreement sales, natural gas contracts with AEPES and other revenues for the years ended December 31, 2012 and 2011:

Related Party Revenues	Years Ended December 31, 2012	2011
	(in thousands)	
Sales under Interconnection Agreement	$ 643,486	$ 823,703
Direct Sales to East Affiliates	136,142	115,120
Direct Sales to West Affiliates	454	1,936
Transmission Agreement and Transmission Coordination Agreement Sales	26,295	3,375
Natural Gas Contracts with AEPES	-	196
Other Revenues	40,917	33,669

The following table shows the purchased power expenses incurred for purchases under Interconnection Agreement and from affiliates for the years ended December 31, 2012 and 2011:

Related Party Purchases	Years Ended December 31, 2012	2011
	(in thousands)	
Purchases under Interconnection Agreement	$ 174,240	$ 326,871
Direct Purchases from West Affiliates	75	312
Purchases from AEGCo	203,583	185,741
Gas Purchases from AEPES	2,808	2,689

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.

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APCo, I&M, KPCo and OPCo are parties to a new TA, effective November 2010, 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). The new TA was phased-in for retail rates and added KGPCo and WPCo as parties to the agreement. OPCo's net charges recorded related to the new TA for the years ended December 31, 2012 and 2011 were $6.1 million and $17.2 million, respectively. The charges are recorded in Operation Expenses.

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

Unit Power Agreements (UPA)

In March 2007, OPCo and AEGCo entered into a ten-year UPA for the entire output from the Lawrenceburg Generating Station effective with AEGCo's purchase of the plant in May 2007. The UPA has an option for an additional two-year period. I&M operates the plant under an agreement with AEGCo. Under the UPA, OPCo pays AEGCo for the capacity, depreciation, fuel, operation and maintenance and tax expenses. These payments are due regardless of whether the plant is operating. The fuel and operation and maintenance payments are based on actual costs incurred. All expenses are trued up periodically.

Cook Coal Terminal

Cook Coal Terminal, a division of OPCo, performs coal transloading services at cost for APCo and I&M. OPCo included revenues of $33.6 million and $21.9 million for the years ended December 31, 2012 and 2011, respectively, for these services in Revenues from Nonutility Operations and expenses in Expenses from Nonutility Operations.

Cook Coal Terminal also performs railcar maintenance services at cost for APCo, I&M, PSO and SWEPCo. OPCo included revenues for these services in Revenues from Nonutility Operations and expenses in Expenses from Nonutility Operations. OPCo's railcar maintenance revenues in 2012 and 2011 were $5.8 million and $5.9 million, respectively.

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. OPCo paid $40 million and $37 million for the years ended December 31, 2012 and 2011, respectively, to I&M and recorded the costs as fuel expense or other operation expense.

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Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. OPCo recorded these billings of $3.8 million and $3.7 million as capital or maintenance expenses depending on the nature of the services received for the years ended December 31, 2012 and 2011, respectively. These billings are recoverable from customers.

Affiliate Railcar Agreement

The AEP East Companies, PSO and SWEPCo have an agreement providing for the use of each other's leased or owned railcars when available. The agreement specifies that the company using the railcar will be billed, at cost, by the company furnishing the railcar. OPCo 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. The following table shows the net effect of the railcar agreement on the balance sheets:

	Years Ended December 31,	APCo	I&M	KPCo	PSO	SWEPCo
				(in thousands)		
Payment of Costs:						
	2012	$ 854	$ 170	$ -	$ 5	$ 99
	2011	840	170	-	8	66
Reimbursement of Costs:						
	2012	1,960	889	41	74	321
	2011	1,373	1,190	355	234	605

OVEC

AEP, OPCo and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2012, AEP's and OPCo's ownership and investment in OVEC were as follows:

	December 31, 2012	
Company	**Ownership**	**Investment**
		(in thousands)
AEP	39.17 %	$ 3,978
OPCo	4.30 %	430
Total	43.47 %	$ 4,408

OVEC's owners, along with APCo and I&M, are members to an intercompany power agreement. Participants of this agreement are entitled to receive and obligated to pay for all OVEC generating capacity, approximately 2,200 MWs, in proportion to their respective power participation ratios. The aggregate power participation ratio of certain AEP utility subsidiaries, including APCo, I&M and OPCo, is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and provide a return on capital. In 2011, the intercompany power agreement was extended until June 2040.

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AEP, OPCo and other nonaffiliated owners authorized environmental investments related to their ownership interests and OVEC's Board of Directors authorized capital expenditures totaling $1.4 billion in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at OVEC's two generating plants. As of December 31, 2012, OVEC completed financing of $1.4 billion required for these environmental projects through debt issuances. As of December 31, 2012, one plant was operating with new environmental controls and the other plant is scheduled to be operational with new environmental controls during the second quarter of 2013.

Purchased Power from OVEC

OPCo paid $125 million and $145 million for power purchased from OVEC for the years ended December 31, 2012 and 2011, respectively. The amounts are recoverable from customers and are included in Operation Expenses.

Purchases from OVEC under the Interconnection Agreement

In 2011, the parties to the Interconnection Agreement purchased power from OVEC to serve off-system sales and retail sales. These purchases are reported in Operation Expenses. The amount recorded for OPCo for the year ended December 31, 2011 was $27.6 million.

Sales and Purchases of Property

OPCo had affiliated sales and purchases of electric property individually amounting to $100 thousand or more and sales and purchases of meters, transformers and transmission property. There were no gains or losses recorded on the transactions. The following table shows the sales and purchases that were recorded in Utility Plant at net book value for the years ended December 31, 2012 and 2011:

	Years Ended December 31, 2012	2011
	(in thousands)	
Sales	$ 4,163	$ 12,113
Purchases	10,608	3,045

Global Borrowing Notes

As of December 31, 2012 and 2011, AEP has an intercompany note in place with OPCo. The debt is reflected in Advances from Associated Companies on the balance sheets. OPCo accrues interest for the global borrowing and remits the interest to AEP.

Intercompany Billings

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

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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. OPCo's total billings from AEPSC were $277 million and $280 million for the years ended December 31, 2012 and 2011, respectively.

14. PROPERTY, PLANT AND EQUIPMENT

Depreciation

OPCo 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	Steam	Other	Hydro	Transmission	Distribution	General
				(in percentages)		
2012	3.8	2.3	2.7	2.3	2.7	1.1
2011	3.2	2.3	2.7	2.3	3.7	8.7

For rate-regulated operations, 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. For nonregulated operations, non-ARO removal costs are expensed as incurred.

Asset Retirement Obligations (ARO)

OPCo 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. OPCo 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 OPCo plans to use its facilities indefinitely. The retirement obligation would only be recognized if and when OPCo abandons or ceases the use of specific easements, which is not expected.

The following is a reconciliation of the 2012 and 2011 aggregate carrying amounts of ARO related to ash disposal facilities and asbestos removal:

Year	ARO as of January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of December 31,
			(in thousands)			
2012	$ 237,120	$ 14,836	$ -	$ (8,223)	$ 21,293	$ 265,026
2011	184,824	13,236	165	(4,870)	43,765	237,120

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Jointly-owned Electric Facilities

OPCo has electric facilities that are jointly-owned with affiliated and nonaffiliated companies. Using its own financing, OPCo is obligated to pay its share of the costs of any such jointly-owned facilities in the same proportion as its ownership interest. OPCo'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:

			OPCo's Share as of December 31, 2012		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
John E. Amos Generating Station (Unit No. 3) (a)	Coal	66.67 %	$ 995,005	$ 14,093	$ 213,163
W.C. Beckjord Generating Station (Unit No. 6) (b)	Coal	12.5 %	-	-	-
Conesville Generating Station (Unit No. 4) (c)	Coal	43.5 %	310,342	26,067	58,677
J.M. Stuart Generating Station (d)	Coal	26.0 %	541,719	11,151	180,687
Wm. H. Zimmer Generating Station (e)	Coal	25.4 %	807,431	1,817	387,209
Transmission	NA	(f)	69,148	4,101	50,516
Total			$ 2,723,645	$ 57,229	$ 890,252

			OPCo's Share as of December 31, 2011		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
John E. Amos Generating Station (Unit No. 3) (a)	Coal	66.67 %	$ 988,510	$ 15,344	$ 188,820
W.C. Beckjord Generating Station (Unit No. 6) (b)	Coal	12.5 %	19,131	108	8,476
Conesville Generating Station (Unit No. 4) (c)	Coal	43.5 %	309,771	11,633	53,980
J.M. Stuart Generating Station (d)	Coal	26.0 %	528,271	13,292	171,830
Wm. H. Zimmer Generating Station (e)	Coal	25.4 %	771,158	19,949	376,585
Transmission	NA	(f)	63,115	5,805	49,487
Total			$ 2,679,956	$ 66,131	$ 849,178

(a) Operated by APCo.
(b) Operated by Duke Energy Corporation, a nonaffiliated company. OPCo's portion of this unit was impaired in the fourth quarter of 2012. See "Impairments" section of Note 5.
(c) Operated by OPCo.
(d) Operated by The Dayton Power & Light Company, a nonaffiliated company.
(e) Operated by Duke Energy Corporation, a nonaffiliated company.
(f) Varying percentages of ownership.
NA Not applicable.

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NOTES TO FINANCIAL STATEMENTS (Continued)

15. COST REDUCTION PROGRAMS

2012 Sustainable Cost Reduction

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

OPCo recorded a charge to expense primarily for severance benefits during 2012 related to the sustainable cost reductions initiative.

Expense Allocation from AEPSC	Incurred for Registrant Subsidiaries	Settled	Remaining Balance as of December 31, 2012
	(in thousands)		
$ 9,225	$ 4,273	$ (10,048)	$ 3,450

2010 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. Many of these eliminated positions resulted from employees that elected retirement through voluntary severance. Most of the affected employees terminated employment as of May 31, 2010. The severance program provided two weeks of base pay for every year of service along with other severance benefits.

For OPCo, who had cost reduction activity remaining as of December 31, 2011, the activity for 2012 is described in the following table:

Balance as of December 31, 2011	Settled	Adjustments	Balance as of December 31, 2012
	(in thousands)		
$ 138	$ (138)	$ -	$ -

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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			(165,525)	(190,604,389)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income			4,473	10,850,385
3	Preceding Quarter/Year to Date Changes in Fair Value				(25,674,441)
4	Total (lines 2 and 3)			4,473	(14,824,056)
5	Balance of Account 219 at End of Preceding Quarter/Year			(161,052)	(205,428,445)
6	Balance of Account 219 at Beginning of Current Year			(161,052)	(205,428,445)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income			4,474	12,961,092
8	Current Quarter/Year to Date Changes in Fair Value				19,559,093
9	Total (lines 7 and 8)			4,474	32,520,185
10	Balance of Account 219 at End of Current Quarter/Year			(156,578)	(172,908,260)

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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	10,978,344	(363,372)	(180,154,942)		
2	(1,363,483)	1,363,925	10,855,300		
3		(2,747,552)	(28,421,993)		
4	(1,363,483)	(1,383,627)	(17,566,693)	464,992,339	447,425,646
5	9,614,861	(1,746,999)	(197,721,635)		
6	9,614,861	(1,746,999)	(197,721,635)		
7	(1,363,481)	2,838,236	14,440,321		
8		(2,002,331)	17,556,762		
9	(1,363,481)	835,905	31,997,083	343,534,107	375,531,190
10	8,251,380	(911,094)	(165,724,552)		

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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)	15,430,834,664	15,430,834,664
4	Property Under Capital Leases	47,233,276	47,233,276
5	Plant Purchased or Sold		
6	Completed Construction not Classified	313,283,310	313,283,310
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	15,791,351,250	15,791,351,250
9	Leased to Others		
10	Held for Future Use	16,588,944	16,588,944
11	Construction Work in Progress	354,496,915	354,496,915
12	Acquisition Adjustments	636,578	636,578
13	Total Utility Plant (8 thru 12)	16,163,073,687	16,163,073,687
14	Accum Prov for Depr, Amort, & Depl	6,670,266,900	6,670,266,900
15	Net Utility Plant (13 less 14)	9,492,806,787	9,492,806,787
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	6,548,879,409	6,548,879,409
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	120,774,423	120,774,423
22	Total In Service (18 thru 21)	6,669,653,832	6,669,653,832
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	50,531	50,531
29	Amortization		
30	Total Held for Future Use (28 & 29)	50,531	50,531
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	562,537	562,537
33	Total Accum Prov (equals 14) (22,26,30,31,32)	6,670,266,900	6,670,266,900

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
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					33

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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year: Amortization (d)	Changes during Year: Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	5,584	
3	(302) Franchises and Consents	71,469	
4	(303) Miscellaneous Intangible Plant	130,693,913	30,814,913
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	130,770,966	30,814,913
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	13,665,713	748,598
9	(311) Structures and Improvements	659,792,941	13,190,330
10	(312) Boiler Plant Equipment	6,871,677,732	109,764,904
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	900,026,295	39,472,852
13	(315) Accessory Electric Equipment	333,584,066	4,347,373
14	(316) Misc. Power Plant Equipment	117,447,139	4,538,221
15	(317) Asset Retirement Costs for Steam Production	138,495,703	21,285,974
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	9,034,689,589	193,348,252
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	3,992	
28	(331) Structures and Improvements	49,979,341	
29	(332) Reservoirs, Dams, and Waterways	6,304,465	
30	(333) Water Wheels, Turbines, and Generators	43,864,725	
31	(334) Accessory Electric Equipment	10,010,232	17,670
32	(335) Misc. Power PLant Equipment	4,430,790	3,613
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production	50,034	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	114,643,579	21,283
36	D. Other Production Plant		
37	(340) Land and Land Rights	3,713,584	
38	(341) Structures and Improvements	14,495,497	3,767,832
39	(342) Fuel Holders, Products, and Accessories	7,547,998	45,075
40	(343) Prime Movers		
41	(344) Generators	324,528,308	2,446,449
42	(345) Accessory Electric Equipment	45,996,888	764,124
43	(346) Misc. Power Plant Equipment	8,484,005	451,864
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	404,766,280	7,475,344
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	9,554,099,448	200,844,879

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	103,698,082	4,700,485
49	(352) Structures and Improvements	85,440,234	99,361
50	(353) Station Equipment	1,041,206,527	36,151,051
51	(354) Towers and Fixtures	172,913,590	118,819
52	(355) Poles and Fixtures	225,376,475	19,317,161
53	(356) Overhead Conductors and Devices	283,108,996	15,454,789
54	(357) Underground Conduit	10,893,770	
55	(358) Underground Conductors and Devicas	19,686,427	
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant	3,120	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,942,327,221	75,841,666
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	49,758,376	2,350,183
61	(361) Structures and Improvements	20,443,066	23,507
62	(362) Station Equipment	507,013,227	30,247,253
63	(363) Storage Battery Equipment	5,062,199	
64	(364) Poles, Towers, and Fixtures	582,110,980	20,629,161
65	(365) Overhead Conductors and Devices	564,481,857	47,134,773
66	(366) Underground Conduit	158,130,586	19,138,085
67	(367) Underground Conductors and Devices	489,513,049	32,064,755
68	(368) Line Transformers	643,093,543	29,002,431
69	(369) Services	282,626,314	11,855,540
70	(370) Meters	155,764,648	31,905,973
71	(371) Installations on Customer Premises	48,844,295	3,261,782
72	(372) Leased Property on Customer Premises	103,793	
73	(373) Street Lighting and Signal Systems	33,937,372	2,949,779
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,540,883,305	230,563,222
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	8,215,449	
87	(390) Structures and Improvements	128,168,414	2,161,047
88	(391) Office Furniture and Equipment	8,078,909	16,621
89	(392) Transportation Equipment	70,645	
90	(393) Stores Equipment	618,560	13,046
91	(394) Tools, Shop and Garage Equipment	29,556,345	2,827,638
92	(395) Laboratory Equipment	1,210,346	
93	(396) Power Operated Equipment	633,681	
94	(397) Communication Equipment	49,628,763	7,661,323
95	(398) Miscellaneous Equipment	3,763,559	311,825
96	SUBTOTAL (Enter Total of lines 86 thru 95)	229,944,671	12,991,500
97	(399) Other Tangible Property	581,471	-56,461
98	(399.1) Asset Retirement Costs for General Plant	298,648	7,393
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	230,824,790	12,942,432
100	TOTAL (Accounts 101 and 106)	15,398,905,730	551,007,112
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	15,398,905,730	551,007,112

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			5,584		2
			71,469		3
22,621,907			138,886,919		4
22,621,907			138,963,972		5
					6
					7
			14,414,311		8
5,010,625		-2,774	667,969,872		9
84,865,844		39,830	6,896,616,622		10
					11
18,845,129			920,654,018		12
4,268,083		24,396	333,687,752		13
2,068,122		7,320	119,924,558		14
3,050,389			156,731,288		15
118,108,192		68,772	9,109,998,421		16
					17
					18
					19
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					22
					23
					24
					25
					26
			3,992		27
			49,979,341		28
			6,304,465		29
			43,864,725		30
9,700			10,018,202		31
			4,434,403		32
					33
			50,034		34
9,700			114,655,162		35
					36
			3,713,584		37
174,947			18,088,382		38
3,208			7,589,865		39
					40
791,945			326,182,812		41
211,546			46,549,466		42
6,235		1	8,929,635		43
					44
1,187,881		1	411,053,744		45
119,305,773		68,773	9,635,707,327		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
1,603		-341,392	108,055,572		48
2,649		-140,341	85,396,605		49
6,911,231		79,067	1,070,525,414		50
8,928			173,023,481		51
2,684,523		-2	242,009,111		52
421,834		-1	298,141,950		53
			10,893,770		54
			19,686,427		55
					56
			3,120		57
10,030,768		-402,689	2,007,735,450		58
					59
		-212,510	51,896,049		60
161			20,466,412		61
3,189,578		-6,078	534,064,824		62
			5,062,199		63
5,397,832		-75	597,342,234		64
10,996,779		6,155	600,626,006		65
201,805			177,066,866		66
3,949,467			517,628,337		67
10,562,523			661,533,451		68
2,517,741		-48,490	291,915,623		69
13,632,907			174,037,714		70
1,604,289			50,501,788		71
			103,793		72
1,018,976			35,868,175		73
					74
53,072,058		-260,998	3,718,113,471		75
					76
					77
					78
					79
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					81
					82
					83
					84
					85
		352,526	8,567,975		86
482,630		-2,951	129,843,880		87
		-7,321	8,088,209		88
			70,645		89
			631,606		90
			32,383,983		91
40,139		-74,293	1,095,914		92
11,353			622,328		93
		48,490	57,338,576		94
26,090		74,293	4,123,587		95
560,212		390,744	242,766,703		96
			525,010		97
			306,041		98
560,212		390,744	243,597,754		99
205,590,718		-204,150	15,744,117,974		100
					101
					102
					103
205,590,718		-204,150	15,744,117,974		104

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	/ /	2012/Q4

FOOTNOTE DATA

Schedule Page: 204 Line No.: 97 Column: g

Nature and Use of Plant Included in Account 399

Land and Land Rights	$429,000
Coal Exploration Equipment	$96,010
	$525,010

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
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47	TOTAL				

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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	North Corridor Marysville Substation 765 KV			
3	Right-of-Way (9520)	02/01/96		418,481
4				
5	Marysville 765KV Substation (2337)	02/01/76		263,474
6				
7	Ridgely Substation (3607)	3/1/2010	2013	469,403
8				
9	Newbury Project (5674)	12/80		4,991,594
10		12/87		61,220
11				
12	Ohio Operations Center (0528)	6/81		506,771
13				
14	North Galloway - West Jefferson 69kV Right-of-Way	5/98		254,004
15	(5684)			
16				
17	Bolton Substation (0269)	5/05	2019	732,264
18				
19	Items Under $250,000			3,553,656
20				
21	Other Property:			
22				
23	Items under $250,000			57,307
24				
25				
26				
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47	Total			16,588,944

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Berrywood Substation (0276)	3/06	2017	252,572
3				
4	Lincoln - Berrywood 69kV (C977)	6/09	2017	256,991
5				
6	Lucasville Service Center (3276)	12/01/2011	2014	447,815
7				
8	South Worthington 138/34.5kV Substation (0383)	8/09	2013	699,997
9				
10	Shanahan Substation (0277)	11/1/2010	2015	264,761
11				
12	South Point Service Center (3069)	7/1/2011	2013	1,074,567
13				
14	Vassell Substation (0300)	5/08	2014	2,284,067
15				
16				
17				
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21	Other Property:			
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47	Total			16,588,944

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	AM FGD Landfill	2,359,652
2	CV U4-6 FGD Landfill	8,102,179
3	TL/OPC/Cambridge Area Subtrans	1,080,560
4	TSOPCPurchase-Rebuild Maj Eq	1,112,998
5	TSOPCOPortsmouth Subtrans	1,322,379
6	TSOPCOWest Moulton Station	5,048,825
7	T/CSP/Security Application Enh	9,911,688
8	TL/CSP/Hyatt-Corridor 345	5,263,935
9	CV CI U4 GSU REPLACEMENT	2,184,472
10	GV U0 Hg at Outfall	6,077,951
11	ML U1&2 Dry Fly Ash Conversion	33,749,639
12	CV CI U4 SILO DUST SUPPRESSON	1,464,891
13	CV CI U56 SILO DUST SUPPRESSON	5,328,931
14	Amos Landfill Seq. 3, 4 OPCo	1,015,753
15	U3 LP Ugrade Shadow Project	7,587,208
16	CD0 Landfill Cells	6,688,063
17	T/CSP/Maj Storm	1,827,292
18	CV CI U4 Jet Bubbling Reactor	7,996,333
19	CV CI U4 HP TURBINE UPGRADE	7,081,300
20	CV CI U456 FGD LANDFL VERT EXP	1,065,542
21	CV CI U4 COAL PIPE REPL	2,185,102
22	CSP/Gay Street Station	1,495,433
23	OP/Install UG Circuit Exit	1,093,804
24	CSP/Cols Arc Flash Mitigation	1,407,414
25	Battelle Assistance and Other	10,816,680
26	Community Energy Storage	2,294,334
27	Cyber Security	3,127,053
28	Oh gSmart Ph1 DA	4,675,842
29	Oh gSmart Ph1 HAN	2,098,801
30	GV Landfill Extension	5,295,247
31	Upgrade LP A,B,C,D Turb Rotor	7,872,424
32	SCR Catalysts	1,694,488
33	ML E BARGE UNLOADER CONTROLS	1,317,288
34	ML New Landfill	10,735,334
35	ML New Landfill Haul Road	4,167,144
36	ML0-S-AUX BOILER REPLACEMENT	20,017,293
37	ML1 S AIR HEATER BASKET REPLAC	1,842,735
38	Elk Run (Carter Hollow LF)	3,113,692
39	T/OPCO/Line Rebuild	2,318,460
40	T/CSP/Line Rebuild	1,182,939
41	TS/OH/Replace & Refurbish	1,840,216
42	DS/OH/Replace & Refurbish	1,901,279
43	TOTAL	354,496,915

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	T/OPCO/Line Rehab/Replace	1,883,702
2	T/CSP/Line Rehab/Replace	1,180,609
3	T/OP/Purchase/Rebuild Maj Eqp	1,076,044
4	T/CSP/Purchase/Rebuild Maj Eqp	1,493,067
5	D/OH/Purchase/Rebuild Maj Eqp	3,231,520
6	T/CSP/CORRIDOR: REPL 3-138	2,358,878
7	T/CSP/Beatty Road: Repl 5-138	1,448,570
8	T/OP/Canton Trans Work	1,114,651
9	TL/OPC/Mt Vernon 69kV Line	3,100,900
10	TL/OPCO/East Lima Sterling 138	1,563,242
11	TL/CSP/COLE-BEATTY-HAYDEN TAP	1,477,529
12	DS/CSP/WEST-NEW SITE D FERC	2,801,673
13	T/OP/ Ohio Power Trans Wrk	5,174,043
14	T/OH/CSP-T Work	-1,281,539
15	ALR Project and Security Inst	1,440,439
16	Waterford HGP Parts	4,333,592
17	ML0-Conners Run Expansion	7,953,190
18	WS-CI-OPCo-G PPB	35,712,884
19	ET-CI-OPCo-T ASSET IMP	8,753,248
20	ET-CI-CSPCo-T ASSET IMP	1,633,358
21	Ed-Ci-Opco-D Ast Imp	3,346,550
22	Ed-Ci-Cspco-D Ast Imp	1,743,918
23	Ed-Ci-Opco-D Cust Serv	2,119,775
24	ET-CI-OPCo-T Drvn D Asset Imp	1,894,122
25	Other Minor Projects Under $1,000,000	50,180,357
26		
27		
28		
29		
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42		
43	TOTAL	354,496,915

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

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

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	5,978,093,131	5,978,043,786	49,345	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	490,269,865	490,269,865		
4	(403.1) Depreciation Expense for Asset Retirement Costs	12,055,617	12,055,617		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	960	-226	1,186	
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	502,326,442	502,325,256	1,186	
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	182,968,614	182,968,614		
13	Cost of Removal	40,507,369	40,507,369		
14	Salvage (Credit)	19,955,765	19,955,765		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	203,520,218	203,520,218		
16	Other Debit or Cr. Items (Describe, details in footnote):	272,030,585	272,030,585		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	6,548,929,940	6,548,879,409	50,531	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	4,024,027,580	4,024,027,580		
21	Nuclear Production				
22	Hydraulic Production-Conventional	78,355,716	78,355,716		
23	Hydraulic Production-Pumped Storage				
24	Other Production	145,880,258	145,880,258		
25	Transmission	817,203,711	817,153,180	50,531	
26	Distribution	1,391,679,118	1,391,679,118		
27	Regional Transmission and Market Operation				
28	General	91,783,557	91,783,557		
29	TOTAL (Enter Total of lines 20 thru 28)	6,548,929,940	6,548,879,409	50,531	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	/ /	2012/Q4

FOOTNOTE DATA

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

Depreciation expense on asbestos ARO	$ 8,000
Depreciation expense on incremental Monongahela costs	14,710
Adjustment for Bell Howell Inserter depreciation expense billed by AEPSC	-22,936
TOTAL	$ -226

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

Depreciation expense on account 105 assets	$1,186

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

Includes $20,032,021 of removal cost in retirement work in progress (RWIP).

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

Includes ($2,402,439) of salvage charges in retirement work in progress (RWIP).

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

ARO Reserve in account 1080013	$ -76,351
Conesville U3 NBV in account 4265002	1,139,821
Reserve transferred between accounts 108, 111,122 and 124	-60,916
Reserve for Impaired Plants - Beckjord, Kammer, Muskingum River U1-4 and Sporn U2 & 4, Picway	271,028,031
TOTAL	$272,030,585

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	CARDINAL OPERATING COMPANY:			
2	Advances - Open Account			130,476
3	250 Shares Common Stock	01/01/68		250
4	Subtotal			130,726
5				
6	CENTRAL COAL COMPANY:			
7	1,500 Shares Common Stock	01/01/48		603,868
8	Subtotal			603,868
9				
10	CONESVILLE COAL PREPARATION COMPANY			
11	Common Stock			109,000
12	Premium on Capital Stock			668,589
13	Equity - Undistributed Earnings			2,204,800
14	Investment in Subsidiary AOCI			-5,551,659
15	Subtotal			-2,569,270
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ -1,804,458		TOTAL	-1,834,676

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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
		130,476		2
		250		3
		130,726		4
				5
				6
		603,868		7
		603,868		8
				9
				10
		109,000		11
		668,589		12
		2,204,800		13
		-5,521,441		14
		-2,539,052		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
		-1,804,458		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	252,654,805	315,658,014	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	10,230,746	13,182,324	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	44,900,534	55,106,749	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	124,074,819	100,900,895	Electric
8	Transmission Plant (Estimated)	991,190	1,602,775	Electric
9	Distribution Plant (Estimated)	2,341,340	2,992,476	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	274,275	223,854	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	172,582,158	160,826,749	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
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)	435,467,709	489,667,087	

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2012/Q4

FOOTNOTE DATA

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2013 No. (d)	2013 Amt. (e)
1	Balance-Beginning of Year	740,132.00	29,879,921	318,467.00	6,347,938
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	AEP System Pool	14,443.00	912,934		
10	Appalachian Power Company	3,457.00	2,198,790		
11	Buckeye Power Inc.	22,610.00			
12					
13					
14	Other				
15	Total	40,510.00	3,111,724		
16					
17	Relinquished During Year:				
18	Charges to Account 509	149,822.00	14,742,770		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Appalachian Power Company	23,969.00	1,450,934		
23	Indiana Michigan Power Co	15,837.00	958,674		
24	Kentucky Power Company	19,019.00	1,151,292		
25					
26					
27	Other				
28	Total	58,825.00	3,560,900		
29	Balance-End of Year	571,995.00	14,687,975	318,467.00	6,347,938
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)		42,054,188		
33	Net Sales Proceeds (Other)				
34	Gains		7,537,909		
35	Losses		1,788,774		
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	4,112.00		4,128.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	4,112.00			
40	Balance-End of Year			4,128.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		2,774		
45	Gains		2,774		
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.

2014 No. (f)	2014 Amt. (g)	2015 No. (h)	2015 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	Line No.
350,555.00	12,759,081	286,748.00		7,470,049.00		9,165,951.00	48,986,940	1
								2
								3
				350,748.00		350,748.00		4
								5
								6
								7
								8
						14,443.00	912,934	9
						3,457.00	2,198,790	10
						22,610.00		11
								12
								13
								14
						40,510.00	3,111,724	15
								16
								17
						149,822.00	14,742,770	18
								19
								20
								21
						23,969.00	1,450,934	22
						15,837.00	958,674	23
						19,019.00	1,151,292	24
								25
								26
								27
						58,825.00	3,560,900	28
350,555.00	12,759,081	286,748.00		7,820,797.00		9,348,562.00	33,794,994	29
								30
								31
							42,054,188	32
								33
							7,537,909	34
							1,788,774	35
3,241.00		3,241.00		195,807.00		210,529.00		36
				6,482.00		6,482.00		37
								38
				3,241.00		7,353.00		39
3,241.00		3,241.00		199,048.00		209,658.00		40
								41
								42
								43
					529		3,303	44
					529		3,303	45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) Issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2013 No. (d)	2013 Amt. (e)
1	Balance-Beginning of Year	80,717.00	833,047	67,331.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	2,980.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Net Purchase Accruals/Rev	477.00	-992,189		
10	Virginia Electric & Power	500.00	25,250		
11	Buckeye Power Company	1,653.00	791,829		
12					
13					
14	Other				
15	Total	2,630.00	-175,110		
16					
17	Relinquished During Year:				
18	Charges to Account 509	44,031.00	-329,548	2,300.00	
19	Other:				
20	Joint Plant & Consumption				
21	Cost of Sales/Transfers:				
22	Allegheny Energy Supply	2,000.00	204,938		
23	Koch Supply & Trading	500.00	96,148		
24	PPL EnergyPlus LLC	4,000.00	52,088		
25	Associated Electric Coop	2,000.00	25,285		
26	Entergy Louisiana LLC	1,273.00	16,621		
27	Other	20,348.00	58,966		
28	Total	30,121.00	454,046		
29	Balance-End of Year	12,175.00	533,439	65,031.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)		747,085		
34	Gains		613,379		
35	Losses		329,099		
	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
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.

2014		2015		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
67,331.00						215,379.00	833,047	1
								2
								3
						2,980.00		4
								5
								6
								7
								8
						477.00	-992,189	9
						500.00	25,250	10
						1,653.00	791,829	11
								12
								13
								14
						2,630.00	-175,110	15
								16
								17
						46,331.00	-329,548	18
								19
								20
								21
						2,000.00	204,938	22
						500.00	96,148	23
						4,000.00	52,088	24
						2,000.00	25,285	25
						1,273.00	16,621	26
						20,348.00	58,966	27
						30,121.00	454,046	28
67,331.00						144,537.00	533,439	29
								30
								31
								32
							747,085	33
							613,379	34
							329,099	35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	/ /	2012/Q4

FOOTNOTE DATA

Schedule Page: 229 Line No.: 27 Column: a

Cost if Sales/Transfers: Other

	Current Year Number	Current Year Amount
Associated Electric Cooperative, Inc.	6,500	713
Brownsville Public Utilities Board	170	0
Central Iowa Power Cooperative	100	11
Constellation Energy Commodities	2,900	4,909
Detroit Edison Company	500	55
DTE Stoneman, LLC	19	0
Element Markets, LLC	730	3
Entergy Louisiana	856	94
Entergy Mississippi, Inc.	1,108	125
Koch Supply & Trading	2,250	11,823
Louisville Gas and Electric	275	2,580
Northeast Texas Electri Coop	141	0
PPL EnergyPlus, LLC	2,500	9,549
Prairie Power, Inc.	5	0
Central Iowa Power Cooperative	50	670
Entergy Arkansas, Inc.	1,020	12,895
Entergy Mississippi, Inc.	1,224	15,539
Total	20,348	58,966

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

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

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

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

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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	Buckeye-Northridge 34.5kv Impact	1,619	186	(5,000)	186
3	Buckeye-Rolling Meadows 34.5kv	1,933	186	(5,000)	186
4	Buckeye-Bradrick 34.5kv Impact	1,329	186		
5	Buckeye-Hauss Cridersville 69kv	857	186		
6	Buckeye Pwr-Biers Run 69kv Impact	15,035	186	(12,000)	186
7	Buckeye Pwr-Blue Creek 345kv	2,265	186		
8	Buckeye Pwr-Clear Creek 69kv	5,409	186	(5,000)	186
9	Buckeye Pwr-Marathon 69kv Study	10,056	186	(6,000)	186
10	Buckeye Pwr-Renrock 69kv Impact	7,452	186	(5,000)	186
11	Buckeye Pwr-Powhattan 69kv Impact	1,509	186	(5,000)	186
12	Buckeye Pwr-Stacy 69kv Impact	1,788	186	(5,000)	186
13	Buckeye Pwr-Stuart Chase 69kv	7,424	186		
14	Buckeye Pwr-Cumberland 34.5kv	6,495	186	(5,000)	186
15	Buckeye Pwr-New Beechwood 138kv	6,547	186	(3,000)	186
16	Buckeye-W Millersport 138kv Impact	1,208	186		
17	Buckeye-Ware 138kv Impact	14,544	186		
18	DP&L-Marysville 345/69kv Impact	10,724	186	(5,000)	186
19	N42-Mountaineer-Belmont 765kv	39,177	186		
20	PJM-#U1-060 E Lima-S Kenton 138kv	8,448	186	(8,797)	186
21	**Generation Studies**				
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Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	PJM-#U4-028 Fostoria-Greenlawn	4,510	186	(1,781)	186
3	PJM-#U4-029 Fostoria-Greenlawn	782	186		
4	PJM-#V1-010 Howard-Fostoria 138kv	1,906	186	(1,906)	186
5	PJM-#V2-001 Howard-Bucyrus 138kv	839	186	(841)	186
6	PJM-#V4-010 Fremont-Tiffin 138kv			(360)	186
7	PJM-#V4-015 Fostoria Central 138kv	13,681	186	(5,678)	186
8	PJM-#W1-002 Tiltonsville-Windsor	149	186	(150)	186
9	PJM-#W2-007 East Leipsic 138kv	1,891	186		
10	PJM-#W2-068 Bluff Point 138kv	784	186	(784)	186
11	PJM-#W3-085 Chatfield-S Tiffin	1,430	186	(1,416)	186
12	PJM-#W3-088 SW Lima 345kv Impact	3,470	186	(3,470)	186
13	PJM-#W3-127 Columbus 14.4kv Study	665	186	(2,120)	186
14	PJM-#W3-128 Sporn-Waterford Study	867	186	(867)	186
15	PJM-#W3-128 Sporn-Waterford Impact	18,419	186	(7,867)	186
16	PJM-#W4-021A Howard 138kv Impact	16,470	186	(16,472)	186
17	PJM-#W4-021A Richland & Crawford	144	186	(1,158)	186
18	PJM-#X1-027 Hanging Rock 138kv	1	186	(1,097)	186
19	PJM-#X3-021 (MECS-PJM) 660MW	1,204	186	(1,204)	186
20	PJM-#X3-023 S Greenwich-Willard	17,002	186	(15,678)	186
21	**Generation Studies**				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	PJM-#X3-030 Shelby 345kv Study	1,311	186	(1,348)	186
3	PJM-#X3-030 Shelby 345kv Impact	45	186	(45)	186
4	PJM-#X3-051 Flatlick 765kv Impact	23,644	186	(13,270)	186
5	PJM-#X3-097 (AMIL-PJM) 614MW	1,481	186	(1,481)	186
6	PJM-#X3-098 (AMIL-PJM) 582MW	1,561	186	(1,561)	186
7	PJM-#X4-003 Mill Creek-Riverview	3,263	186	(3,032)	186
8	PJM-#X4-003 Mill Creek-Riverview	12,400	186	(1,730)	186
9	PJM-#X4-025 Milbrook Park 138kv	1,899	186	(1,676)	186
10	PJM-#Y1-018 Conesville #5 345kv	1,148	186	(231)	186
11	PJM-#Y1-019 Conesville #6 345kv	608	186	(456)	186
12	PJM-#Y1-030 Forest 69kv Impact	2,445	186	(2,024)	186
13	PJM-#Y1-063 Trenton 34.5kv Study	8,596	186	(8,596)	186
14	PJM-#Y1-064 Berkshire 34.5kv Study	8,426	186	(8,426)	186
15	PJM-#Y2-050 Carroll 345kv Study	919	186	(271)	186
16	PJM-#Y2-057 Wyandot 13kv Study	152	186	(152)	186
17	PJM-#Y2-085 Canton Central-Tidd	108	186		
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21	**Generation Studies**				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	SFAS 109 Deferred FIT	172,590,653	92,453,137	Various	93,995,158	171,048,632
2						
3	SFAS 109 Deferred SIT	20,412,947	11,373,106	Various	10,502,817	21,283,236
4						
5	SFAS 112 Post Employment Benefits	8,669,172		2283	1,011,422	7,657,750
6						
7	Unrealized Loss on Forward Committments	9,930,038	36,571,058	244, 254	45,691,518	809,578
8						
9	Deferred Distribtuion Storm Expense	8,374,775	64,548,897	593	11,095,604	61,828,068
10	- Case No. 11-346-EL-SSO					
11	- Case No. 11-348-EL-SSO					
12	- Case No. 11-351-EL-AIR					
13	- Case No. 11-352-EL-AIR					
14						
15	BridgeCo TO Funding	1,918,667		4073	166,842	1,751,825
16	- Per FERC Docket No AC04-101-000					
17	- Amortization period - 1/2005 to 12/2019					
18						
19	PJM Integration Program	2,560,137		4073	789,415	1,770,722
20	- Per FERC Docket No EL05-74-000					
21	- Amortization period - 1/2005 to 12/2014					
22						
23	Other PJM Integration	1,718,265		4073	149,403	1,568,862
24	- Per FERC Docket No AC04-101-000					
25	- Amortization period - 1/2005 to 12/2019					
26						
27	Carry Chgs-RTO Start-up Costs	1,441,084	689,315	4073	902,594	1,227,805
28	- Per FERC Docket No AC04-101-000 and EL05-74-000					
29	- Amortization period - 1/2005 up to 12/2019					
30						
31	Alliance RTO Deferred Expense	1,351,352		4073	117,473	1,233,879
32	- Per FERC Docket No AC04-101-000					
33	- Amortization period - 1/2005 to 12/2019					
34						
35	Unrecovered Fuel Cost	466,176,891	65,596,765	501	61,346,603	470,427,053
36	- Ohio ESP - Case No. 08-918-EL-SSO					
37	- Ohio ESP - Case No. 08-917-EL-SSO					
38						
39	Carrying Charges-Ohio Fuel Adjustment Clause	86,897,761	30,955,426	Various	16,861,473	100,991,714
40	- Ohio ESP - Case No. 08-918-EL-SSO					
41	- Ohio ESP - Case No. 08-917-EL-SSO					
42						
43						
44	TOTAL	1,357,975,634	812,741,719		761,321,481	1,409,395,872

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Deferred Equity Carrying Charges - Ohio FAC	(46,466,748)	9,014,484	1823	15,371,208	-52,823,472
2	- Ohio ESP - Case No. 08-918-EL-SSO					
3	- Ohio ESP - Case No. 08-917-EL-SSO					
4						
5	Under-Recovered Ohio TCR Rider	28,403,984	30,976,957	566	11,431,774	47,949,167
6	- Docket No. 05-1194-EL-UNC					
7						
8	Carrying Charge Under Recovered Ohio TCR Rider		1,441,300			1,441,300
9	- Docket No. 05-1194-EL-UNC					
10						
11	SFAS 158 Employers' Accounting for Defined					
12	Benefit Pension and Other Postretirement Plans	389,712,336	309,686,320	2283	389,714,251	309,684,405
13						
14	Under Recovered ESRP Costs-OH	4,453,872	10,902,039	593	14,798,652	557,259
15	- ESRP-Enhanced Service Reliability Plan					
16	- Ohio ESP - Case No. 08-918-EL-SSO					
17	- Ohio ESP - Case No. 08-917-EL-SSO					
18						
19	EDR Deferral	10,012,271	13,292,478	555	20,404,495	2,900,254
20	- EDR - Economic Development Rider					
21	- Case No. 09-119-EL-AEC					
22	- Case No. 09-516-EL-AEC					
23	- Case No. 08-884-EL-AEC					
24	- Case No. 10-3066-EL-AEC					
25						
26	EDR Carrying Charges	1,726,207	1,874,609	254, 421	1,013,111	2,587,705
27	- EDR - Economic Development Rider					
28	- Case No. 09-119-EL-AEC					
29	- Case No. 09-516-EL-AEC					
30	- Case No. 08-884-EL-AEC					
31	- Case No. 10-3066-EL-AEC					
32						
33	EDR Excess Cap Deferral	12,000,000				12,000,000
34	- EDR - Economic Development Rider					
35	- Case No. 09-119-EL-AEC					
36						
37	EDR Excess Cap Deferral Carrying Charges	571,980	640,800			1,212,780
38	- EDR - Economic Development Rider					
39	- Case No. 09-119-EL-AEC					
40						
41						
42						
43						
44	TOTAL	1,357,975,634	812,741,719		761,321,481	1,409,395,872

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	PWO Deferred Asset	3,400,000		4265	995,122	2,404,878
2	- PWO - Partnership With Ohio					
3	- Case No. 11-352-EL-AIR					
4	- Amortization periods - 1/2012 up to 05/2015					
5						
6	DARR Distibution Deferred Assets	86,447,400	2,530,925	Various	13,137,857	75,840,468
7	- DARR - Deferred Asset Recovery Rider					
8	- Case No. 11-352-EL-AIR					
9	- Amortization periods - 1/2012 up to 12/2018					
10						
11	DARR Carrying Charges	240,337,564		1823, 4073	29,360,643	210,976,921
12	- DARR - Deferred Asset Recovery Rider					
13	- Case No. 11-352-EL-AIR					
14	- Amortization periods - 1/2012 up to 12/2018					
15						
16	DARR Unrecognized Equity Carrying Charges	(153,511,037)	18,732,843			-134,778,194
17	- DARR - Deferred Asset Recovery Rider					
18	- Case No. 11-352-EL-AIR					
19	- Amortization periods - 1/2012 up to 12/2018					
20						
21	Deferred Equity Carrying Chgs-Non Fuel	(1,153,937)	194,820			-959,117
22	- Amortization periods - 1/2005 up to 12/2019					
23						
24	DIR Under-Recovery		2,307,334	Various	524,366	1,782,968
25	- DIR - Distribution Investment Rider					
26	- Case No. 11-346-EL-SSO					
27	- Case No. 11-348-EL-SSO					
28						
29	Dist Decoup Rev Prog Under-Recovery		20,497,457	440, 442	4,299,143	16,198,314
30	- Distribution Decoupling Revenue Program					
31	- Case No. 11-351-EL-AIR					
32	- Case No. 11-352-EL-AIR					
33						
34	Under-Recovery Capacity Cost		81,912,529	Various	16,638,923	65,273,606
35	-Case No. 10-2929-EL-UNC					
36	- Case No. 11-346-EL-SSO					
37	- Case No. 11-348-EL-SSO					
38						
39	Capacity Cost Carrying Charges		544,360			544,360
40	-Case No. 10-2929-EL-UNC					
41	- Case No. 11-346-EL-SSO					
42	- Case No. 11-348-EL-SSO					
43						
44	TOTAL	1,357,975,634	812,741,719		761,321,481	1,409,395,872

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	DIR Unrecognized Equity			1823, 254	478,905	-478,905
2	- DIR - Distribution Investment Rider					
3	- Case No. 11-346-EL-SSO					
4	- Case No. 11-348-EL-SSO					
5						
6	Def OH Auction Exp - Incremental		28,709			28,709
7						
8	Uncoll-EDR Delayed Pmt Amgmnt		5,453,342			5,453,342
9	-Uncollectible EDR Delayed Payment Arrangement					
10	- Case No. 09-119-EL-AEC					
11						
12	Load Factor Prov Under-Recovery		522,709	Various	522,709	
13	- Load Factor Provision					
14	- Case No. 11-346-EL-SSO					
15	- Case No. 11-348-EL-SSO					
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43						
44	TOTAL	1,357,975,634	812,741,719		761,321,481	1,409,395,872

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Allowances	105,953	3,618,598	Various	3,710,211	14,340
2						
3	Deferred Expenses	2,321,757	14,954,354	Various	16,707,926	568,185
4						
5	Deferred Property Taxes	226,349,491	224,255,676	Various	220,405,837	230,199,330
6						
7	Cook Coal Terminal - Opr Exp	712,234	6,923,246	930.2	7,332,964	302,516
8						
9	Real Estate Subsidence	728,150				728,150
10						
11	Agency Fees - Factored A/R	6,933,894	63,667,822	Various	64,588,211	6,013,505
12						
13	Defrd Property Tax - Cap Leases	5,252	491,685	236/4081	492,934	4,003
14						
15	Estimated Barging Bills	93,009	73,786,230	Various	73,879,239	
16						
17	Defrd Cook Coal Term Lease Exp	140,688		931	46,896	93,792
18						
19	MDD-Railcar Lease Exp		5,977,107	Various	5,846,782	130,325
20						
21	Unamortized Credit Line Fees	2,766,059	114,947	431, 146	1,579,846	1,301,160
22	Amortized through July 2016					
23						
24	Defd Depr&Capcty Portion -Affl	11,044,262	202,764			11,247,026
25						
26	Deferred Expenses - Current	357,086	1,752,005	Various	2,103,319	5,772
27						
28	Liquidated Rail Damages	4,024,600	18,573,467	Various	20,646,117	1,951,950
29						
30	SCR Catalyst Modules		134,400			134,400
31						
32	Def Lease Assets - Non Taxable	114,791	1,390,441	Various	598,773	906,459
33						
34						
35						
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45						
46						
47	Misc. Work in Progress	1,181,952				4,646,388
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	256,879,178				258,247,301

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Contributions in Aid of Construction	21,450,798	25,097,783
3	Accrued Book ARO Expense - SFAS 143	82,811,800	92,579,028
4	Deferred State Income Taxes	33,417,694	47,259,908
5	Interest Expense Capitalized for Tax	88,283,287	91,066,681
6	SFAS 106 Post Retirement Expenses	25,336,044	25,131,859
7	Other	162,143,458	78,437,542
8	TOTAL Electric (Enter Total of lines 2 thru 7)	413,443,081	359,572,801
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify) Nonutility, SFAS 109, 87 & 133	152,218,832	138,026,163
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	565,661,913	497,598,964

Notes

	(b)	(c)
Nonutility Items - 190.2	43,464,357	46,671,811
SFAS 109 - 190.3 & 190.4	(165,851)	439,209
SFAS 87 - 190.0009 & 190.0016	107,775,264	90,273,201
SFAS 133 - 190.0006	1,145,062	641,942
Total Line 17	152,218,832	138,026,163

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

Balance at Beginning of Year	$565,661,913
(Less) Amounts Debited to:	
(a) Account 410.1	(123,490,137)
(b) Account 410.2	(14,915,652)
(c) Various	(187,622,872)
(Plus) Amounts Credited to:	
(a) Account 409.3	0
(b) Account 411.1	94,309,366
(c) Account 411.2	7,278,274
(d) Various	156,378,072
Balance at End of Year	$497,598,964

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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	40,000,000		
2				
3	Total Common	40,000,000		
4				
5				
6	Preferred Stock: None			
7				
8	Total Preferred			
9				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	
27,952,473	321,201,454					1
						2
27,952,473	321,201,454					3
						4
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	208 - Donations Received from Stockholders	1,081,035,096
2	Subtotal	1,081,035,096
3		
4		
5		
6	209 - Reduction in Par or Stated Value of Capital Stock: NONE	
7	Subtotal	
8		
9		
10		
11	210 - Gain on Resale or Cancellation of Reacquired Capital Stock	-3,057,087
12	Subtotal	-3,057,087
13		
14		
15		
16	211 - Miscellaneous Paid-in Capital	
17	Recorded in connection with merger of Central Ohio Light and	
18	Power Company with respondent in 1955	168,748
19	Overestimated costs of financing	196,599
20	Preferred Stock redemption gains due to implementation of SFAS150	1,193,926
21	Recorded in connection with merger of Columbus Southern Power	
22	Company with respondent in 2011:	
23	201 - Common Stock Issued Affiliated	41,026,065
24	207 - Premium on Common Stock	257,892,418
25	208 - Donations Received from Stockholders	332,200,000
26	210 - Gain on Resale or Cancelled Reacquired Capital Stock	-1,433,630
27	211 - Miscellaneous Paid-in Capital	-7,746,484
28	Subtotal	623,497,642
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	1,701,475,651

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 221 - BONDS:		
2	NONE		
3	Total FERC 221:		
4			
5	ACCOUNT - 222 - REACQUIRED BONDS		
6			
7	Marshall County Series F Bonds, Variable Rate Due 04/2022	-35,000,000	
8			
9	Marshall County Series E Bonds, Variable Rate Due 06/2022	-50,000,000	
10			
11	Ohio Air Quality Development Series 2005A, Variable Rate Due 01/2029	-54,500,000	
12			
13	Ohio Air Quality Development Series 2005B, Variable Rate Due 07/2028	-54,500,000	
14			
15	Ohio Air Quality Development Series 2005C, Variable Rate Due 04/2028	-54,500,000	
16			
17	Ohio Air Quality Development Series 2005D, Variable Rate Due 10/2028	-54,500,000	
18			
19	WV Economic Development Mitchell Series 2008A, Variable Rate Demand Note Due 4/2036	-65,000,000	
20			
21	WV Economic Development Sporn Series 2008C, Variable Rate Demand Note Due 07/2014	-50,000,000	
22			
23	Ohio Air Quality Revenue Bond Series 2007A, Variable Rate Due 08/2040	-44,500,000	
24			
25	Total FERC 222:	-462,500,000	
26			
27	ACCOUNT 223 - ADVANCES FROM ASSOC COMPANIES		
28			
29	Fixed Rate Promissory Notes Payable to Parent		
30	5.250% Due 06/2015	200,000,000	
31			
32	Total FERC 223:	200,000,000	
33	TOTAL	4,062,325,000	47,182,232

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 224 - OTHER LONG-TERM DEBT		
2			
3	Installment Purchase Contracts:		
4			
5	Ohio Air Quality Revenue Bonds 5.10% Series 2007B Due 11/2042	56,000,000	1,101,717
6	*Bond subject to mandatory tender for purchase (puttable) on 05/01/13		
7			
8	Ohio Air Quality Revenue Bonds 3.875% Series 2009A Due 12/2038	60,000,000	656,061
9	*Bond subject to mandatory tender (puttable) on 06/01/14		
10			
11	Ohio Air Quality Revenue Bonds 5.80% Series 2009B Due 12/2038	32,245,000	446,770
12			
13	Ohio Air Quality Revenue Bonds 5.15% Series C Due 05/2026	50,000,000	998,500
14			
15	Marshall County Series F, Variable Rate Due 04/2022	35,000,000	163,995
16			
17	Marshall County Series E, Variable Rate Due 06/2022	50,000,000	425,000
18			
19	Mitchell Series 2007A, 4.90% due 06/2037	65,000,000	581,256
20			
21	Ohio Air Quality Development Series 2005A, Variable Rate Due 01/2029	54,500,000	300,438
22			
23	Ohio Air Quality Development Series 2005B, Variable Rate Due 07/2028	54,500,000	300,438
24			
25	Ohio Air Quality Development Series 2005C, Variable Rate Due 04/2028	54,500,000	300,437
26			
27	Ohio Air Quality Development Series 2005D, Variable Rate Due 10/2028	54,500,000	300,437
28			
29	WV Economic Development Amos Series 2010A, 3.125% Due 03/2043	86,000,000	688,792
30	*Bond subject to mandatory tender for purchase (puttable) on 04/01/15		
31			
32			
33	TOTAL	4,062,325,000	47,182,232

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Ohio Air Quality Development Authority Cardinal Series 2010A, 3.25% Due 06/2041	79,450,000	984,190
2	*Bond subject to mandatory tender for purchase (puttable) on 06/02/14		
3			
4	Ohio Air Quality Development Authority Gavin Series 2010A, 2.875% Due 12/2027	39,130,000	542,989
5	*Bond subject to mandatory tender for purchase (puttable) on 08/01/14		
6			
7	Ohio Air Quality Revenue Bonds, 4.85% Series 2007A Due 08/2040	44,500,000	928,466
8	*Bond subject to mandatory tender for purchase (puttable) on 05/01/12		
9			
10	WV Economic Development Mitchell Series 2008A, Variable Rate Demand Note Due04/2036	65,000,000	332,083
11			
12	WV Economic Development Kammer Series 2008B, Variable Rate Demand Note Due 07/2014	50,000,000	282,353
13			
14	WV Economic Development Sporn Series 2008C, Variable Rate Demand Note Due 07/2014	50,000,000	273,786
15			
16	Ohio Air Quality Revenue Bonds Series 2007A, Variable Rate Due 08/2040	44,500,000	
17			
18	Letter of Credit Fees associated with Variable Rate Demand Notes		
19			
20	Unsecured Senior Notes:		
21			
22	5.50% Unsecured Medium Term Notes Series A Due 03/2013	250,000,000	1,625,000
23			657,500 D
24			
25	6.60% Unsecured Medium Term Notes Series B Due 03/2033	250,000,000	2,187,500
26			1,180,000 D
27			
28	5.85% Unsecured Medium Term Notes Series F Due 10/2035	250,000,000	2,187,500
29			2,815,000 D
30			
31	6.05% Unsecured Medium Term Notes Series G Due 05/2018	350,000,000	2,347,096
32			791,000 D
33	TOTAL	4,062,325,000	47,182,232

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	5.50% Unsecured Medium Term Notes Series F Due 02/2013	250,000,000	1,805,904
2			647,500 D
3			
4	6.60% Unsecured Medium Term Notes Series G Due 02/2033	250,000,000	2,368,087
5			1,165,000 D
6			
7	4.85% Unsecured Medium Term Notes Series H Due 01/2014	225,000,000	1,697,821
8			184,500 D
9			
10	6.375% Unsecured Medium Term Notes Series I Due 07/2033	225,000,000	2,204,350
11			1,845,000 D
12			
13	6.00% Unsecured Medium Term Notes Series K Due 06/2016	350,000,000	2,449,572
14			1,235,500 D
15			
16	Amortization of Cash Flow Hedge on 6.00% SUN		
17			
18	5.75% Unsecured Medium Term Notes Series L Due 09/2013	250,000,000	1,676,238
19			200,000 D
20			
21	5.375% Unsecured Notes Series M Due 10/2021	500,000,000	3,682,837
22			2,065,000 D
23	Amortization of Cash Flow Hedge on 5.375% SUN		
24			
25	Floating Rate Unsecured Notes Series A Due 03/2012	150,000,000	556,619
26			
27	Total FERC 224:	4,324,825,000	47,182,232
28	Footnote:		
29			
30			
31			
32			
33	TOTAL	4,062,325,000	47,182,232

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
						5
						6
05/05/08	04/01/22			-35,000,000	-112,575	7
						8
05/05/08	06/01/22			-50,000,000	-515,445	9
						10
01/21/05	01/01/29			-54,500,000	-199,121	11
						12
01/21/05	07/01/28			-54,500,000	-199,121	13
						14
01/21/05	04/01/28			-54,500,000	-211,868	15
						16
01/21/05	10/01/28			-54,500,000	-199,121	17
						18
06/05/08	04/01/36			-65,000,000	-95,885	19
						20
06/23/08	07/01/14			-50,000,000	-79,522	21
						22
05/01/12	08/01/40			-44,500,000	-95,563	23
						24
				-462,500,000	-1,708,221	25
						26
						27
						28
						29
02/05/04	06/01/15			200,000,000	10,500,000	30
						31
				200,000,000	10,500,000	32
				3,867,825,000	212,506,228	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
11/20/07	11/01/42	11/20/07	05/01/13	56,000,000	2,856,000	5
						6
						7
08/19/09	12/01/38	08/19/09	06/01/14	60,000,000	2,325,000	8
						9
						10
08/19/09	12/01/38	08/19/09	12/01/38	32,245,000	1,870,210	11
						12
05/13/99	05/01/26	05/01/99	05/01/26	50,000,000	2,575,000	13
						14
07/29/05	04/01/22	07/19/05	04/01/22	35,000,000	112,575	15
						16
12/17/03	06/01/22	12/17/03	06/01/22	50,000,000	515,445	17
						18
06/13/07	06/01/37	06/13/07	06/01/37	65,000,000	3,185,000	19
						20
01/21/05	01/01/29	01/21/05	08/18/09	54,500,000	199,121	21
						22
01/21/05	07/01/28	01/21/05	09/08/09	54,500,000	199,121	23
						24
01/21/05	04/01/28	01/21/05	09/01/09	54,500,000	211,868	25
						26
01/21/05	10/01/28	01/21/05	08/11/09	54,500,000	199,121	27
						28
03/24/10	03/01/43	03/24/10	04/01/15	86,000,000	2,687,500	29
						30
						31
						32
				3,867,825,000	212,506,228	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
05/27/10	06/01/41	05/27/10	06/02/14	79,450,000	2,582,125	1
						2
						3
08/20/10	12/01/27	08/20/10	08/01/14	39,130,000	1,124,987	4
						5
						6
08/15/07	08/01/40	08/15/07	05/01/12		719,417	7
						8
						9
06/05/08	04/01/36	06/05/08	04/01/36	65,000,000	95,885	10
						11
06/23/08	07/01/14	06/23/08	07/01/14	50,000,000	73,949	12
						13
06/23/08	07/01/14	06/23/08	07/01/14	50,000,000	79,522	14
						15
05/01/12	08/01/40	05/01/12	08/01/40	44,500,000	95,563	16
						17
						18
						19
						20
						21
02/14/03	03/01/13	02/14/03	03/01/13	250,000,000	13,750,000	22
						23
						24
02/14/03	03/01/33	02/14/03	03/01/33	250,000,000	16,500,000	25
						26
						27
10/14/05	10/01/35	10/14/05	10/01/35	250,000,000	14,625,000	28
						29
						30
05/16/08	05/01/18	05/16/08	05/01/18	350,000,000	21,175,000	31
						32
				3,867,825,000	212,506,228	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
02/14/03	02/15/13	02/14/03	02/15/13	250,000,000	13,750,000	1
						2
						3
02/14/03	02/15/33	02/14/03	02/15/33	250,000,000	16,500,000	4
						5
						6
07/11/03	01/15/14	07/11/03	01/15/14	225,000,000	10,912,500	7
						8
						9
07/11/03	07/15/33	07/11/03	07/15/33	225,000,000	14,343,750	10
						11
						12
06/12/06	06/01/16	06/12/06	06/01/16	350,000,000	21,000,000	13
						14
						15
					-418,450	16
						17
09/09/08	09/01/13	09/09/08	09/01/13	250,000,000	14,375,000	18
						19
						20
09/24/09	10/01/21	09/24/09	10/01/21	500,000,000	26,875,000	21
						22
					-1,679,213	23
						24
03/16/10	03/16/12	03/16/10	03/16/12		298,453	25
						26
				4,130,325,000	203,714,449	27
						28
						29
						30
						31
						32
				3,867,825,000	212,506,228	33

Name of Respondent Ohio Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2012/Q4

FOOTNOTE DATA

Schedule Page: 256 Line No.: 23 Column: a
Ohio Air Quality Revenue Bond, Variable Rate, Series 2007A, Due 08/01/2040 was repurchased on 05/01/2012 (orginally issued on 08/15/2007).

Schedule Page: 256.1 Line No.: 5 Column: a
Ohio Air Quality Revenue Bond 5.10% Series 2007B has a Mandatory Tender Date (PUT Date) of 05/01/2013.

Schedule Page: 256.1 Line No.: 8 Column: a
Ohio Air Quality Revenue Bond 3.875% Series 2009A has a Mandatory Tender Date (PUT Date) of 06/01/2014.

Schedule Page: 256.1 Line No.: 21 Column: a
Issuance: Variable Rate,Ohio Air Quality Development,Series 2005A,Due 01/2029
Principal Amount: $54,500,000
Date of JMG Transfer: 12/15/2009
Date of Reacquisition: 08/18/2009
- Unamortized expense, premium or discount expensed at date of reacquisition.

Schedule Page: 256.1 Line No.: 23 Column: a
Issuance: Variable Rate,Ohio Air Quality Development,Series 2005B,Due 07/2028
Principal Amount: $54,500,000
Date of JMG Transfer: 12/15/2009
Date of Reacquisition: 09/08/2009
- Unamortized expense, premium or discount expensed at date of reacquisition.

Schedule Page: 256.1 Line No.: 25 Column: a
Issuance: Variable Rate,Ohio Air Quality Development,Series 2005C,Due 04/2028
Principal Amount: $54,500,000
Date of JMG Transfer: 12/15/2009
Date of Reacquisition: 09/01/2009
- Unamortized expense, premium or discount expensed at date of reacquisition.

Schedule Page: 256.1 Line No.: 27 Column: a
Issuance: Variable Rate,Ohio Air Quality Development,Series 2005D,Due 10/2038
Principal Amount: $54,500,000
Date of JMG Transfer: 12/15/2009
Date of Reacquisition: 08/11/2009
- Unamortized expense, premium or discount expensed at date of reacquisition.

Schedule Page: 256.1 Line No.: 29 Column: a
West Virginia Development Development Authority Amos Bond 3.125% Series 2010A has a Mandatory Tender Date (PUT Date) of 04/01/2015.

Schedule Page: 256.2 Line No.: 1 Column: a
Ohio Air Quality Development Authority Cardinal Bond 3.25% Series 2010A has a Mandatory Tender Date (PUT Date) of 06/02/2014.

Schedule Page: 256.2 Line No.: 4 Column: a
Ohio Air Quality Development Authority Gavin Bond 2.875% Series 2010A has a Mandatory Tender Date (PUT Date) of 08/01/2014.

Schedule Page: 256.2 Line No.: 7 Column: a
Ohio Air Quality Revenue Bond 4.85% Series 2007A has a Mandatory Tender Date (PUT Date) of 05/01/2012, at which time it was remarketed and is currently included in reacquired bonds of the Company.

Schedule Page: 256.2 Line No.: 12 Column: a
West Virginia Economic Development Authority Kammer Bond, Variable Rate, Series 2008B, Due 07/01/2014 was remarketed on 03/01/2011 (originally issued on 06/23/2008).

Schedule Page: 256.2 Line No.: 16 Column: a
Ohio Air Quality Revenue Bond, Variable Rate, Series 2007A, Due 08/01/2040 was repurchased on 05/01/2012 (orginally issued on 08/15/2007).

Schedule Page: 256.3 Line No.: 28 Column: a
The difference between the total interest on this schedule and the total of accounts 427 and 430 is due to interest on short-term advances from the AEP Money Pool.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	343,534,107
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	339,000,688
28	Show Computation of Tax:	
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	/ /	2012/Q4

FOOTNOTE DATA

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

		In (000's)
Net Income for the year per Page 117		343,534
Federal Income Taxes		172,658
State Income Taxes		(28,140)
Pretax Book Income		488,052
Increase (Decrease) in Taxable Income resulting from:		
AFUDC / Interest Capitalized		(1,531)
Amortization of Pollution Control Equip		(65,508)
Emission Allowances (Net)		8,798
Excess Tax vs Book Depreciation		(124,239)
Mark-to-Market		(4,657)
Deferred Storm Damage		(53,453)
Pension Expenses		(20,840)
Deferred Revenue - Bonus Lease		(1,838)
Removal Costs		(27,414)
Federal and State Mitigation Programs		(2,271)
Book/Tax Unit of Property Adj		(77,137)
Book Leases Cap'd for Tax		(1,645)
Accrued ARO Expense - SFAS 143		27,906
Provision for Revenue Refunds		4,689
Capacity Cost Carrying Charges		(65,818)
Deferred Equity Carrying Charges		(10,036)
Ohio Transmission Cost Rider		13,507
Deferred Asset Recovery Rider		22,230
Medicare Subsidy		3,109
Book Loss Provision - Plant M&S		(2,335)
Deferred Fuel Costs		(18,344)
Accrued Incentive Compensation		7,919
Accrued Partnership Ohio & Ohio Growth Fund		(30,985)
Enhanced Service Reliability Plan		3,897
SFAS 112 Post Employment Benefit		(2,686)
Accrued SIT Reserve		(5,631)
Charitable Contribution Carryforward		2,747
Impaired Assets		287,027
Nondeductible Items		3,180
Other (Net)		(5,479)
Estimated Current Year Taxable Income Before State Income Tax (Separate Return Basis)		351,214
Less State Income Tax		(12,214)
Federal Taxable Income		339,000
		=======
Computation of Tax *		
Federal Income Tax on Current Year Taxable Income (Separate Return Basis) at the Statutory Rate of 35%		118,650
Adjustment due to System Consolidation	(a)	(11,915)
Estimated Tax Currently Payable	(b)	106,735
Tax Provision Adjustment		31
Adjustments of Prior Year's Accruals (Net)		(13,812)
Estimated Current Federal Income Taxes (Net)		92,954
		=======

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	/ /	2012/Q4

FOOTNOTE DATA

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

(b) The Company joins in the filing of a consolidated Federal income tax return with its affiliated companies in the AEP system. The allocation of the AEP System's consolidated Federal income tax to the System companies allocates the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, American Electric Power Company, Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidating group.

INSTRUCTION 2.

* The tax computation above represents an estimate of the Company's allocated portion of the System consolidated Federal income tax. The computation of actual 2012 System Federal income taxes will not be available until the consolidated Federal income tax return is completed and filed by September 2013. The actual allocation of the System consolidated Federal income tax to the members of the consolidated group will not be available until after the consolidated federal income tax return is filed.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL:					
2	INCOME TAX	-8,883,022		92,930,577	80,763,998	-17,759,808
3	FICA - 2012	2,130,046		18,663,139	18,251,071	
4	Unemployment - 2012	96,749		203,830	179,178	
5	EXCISE TAX - 2011			7,654	7,654	
6	EXCISE TAX - 2012			31,249	31,249	
7						
8	STATE OF OHIO:					
9	CAT TAX - 2011	2,679,000		202,880	2,881,880	
10	CAT TAX - 2012			10,396,850	7,723,850	
11	OCC & PUCO FEES - 2012			5,879,061	5,879,061	
12	KWH State Excise Tax - 2011	12,249,531			12,249,531	
13	KWH State Excise Tax - 2012			143,109,283	130,660,979	
14	SALES & USE - 2011	341,326	131,549	-87,882	121,895	
15	SALES & USE - 2012			1,494,608	1,315,266	
16	Unemployment - OH 2012	47,867		113,945	161,160	
17	INCOME TAX - 2000			-6,145,609	-6,145,608	
18						
19	STATE OF ILLINOIS:					
20	INCOME TAX 2011	289,508		-323,255	-33,747	
21	INCOME TAX 2012			934,214	454,047	
22	SALES & USE - 2011	13,968		-1,974	11,994	
23	SALES & USE - 2012			107,710	91,056	
24	Unemployment - IL 2012	1,310		36,847	37,703	
25						
26	STATE OF WEST VIRGINIA:					
27	INCOME TAX - 2006					
28	INCOME TAX - 2009	-7				
29	INCOME TAX - 2010					
30	INCOME TAX - 2011	-3,008,008		810,182	-2,197,826	
31	INCOME TAX - 2012			13,306,549	3,031,000	
32	STATE FRAN. 09&PRIOR	-11,884		610,117	610,117	
33	STATE FRAN. 2011	47,683		-61,721	-14,038	
34	STATE FRAN. 2012			7,676	22,101	
35	Unemployment - WV 2012	7,298		48,261	55,559	
36	SALES & USE TAX - 2011	22,419		-2,085	20,334	
37	SALES & USE TAX -2012			144,218	123,169	
38	BUS & OCCUPATION-2011	1,336,231		145,036	1,481,267	
39	BUS & OCCUPATION-2012			15,735,811	14,572,102	
40	BUS & OCCUPATION-Audit	3,327,200		327,500		
41	TOTAL	437,248,507	131,549	516,750,340	485,904,321	-19,160,029

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1						
2						
3	LOCAL:					
4	Real & Pers-2009 OH			-7,090	-7,090	
5	Real & Pers-2010 OH	193,193,195		365,544	193,558,739	
6	Real & Pers-2011 OH	203,260,595		-1,911,810	-8,163	
7	Real & Pers-2012 OH			208,575,970		
8						
9	Re Prop-Leased 2011 OH	206,391		-4,086	203,338	
10	Re Prop-Leased 2012 OH			210,434		
11						
12	Pers Prop-Leased 2009 OH	24,933		-24,933		
13	Pers Prop-Leased 2010 OH	235,278		-217,152	18,126	
14	Pers Prop-Leased 2011 OH	448,474		-83,057	165,417	
15	Pers Prop-Leased 2012 OH			270,700		
16						
17	RE & Pers Prop-2010 WV	7,790,720			7,790,720	
18	RE & Pers Prop-2011 WV	15,438,710		-364,696	7,537,007	
19	RE & Pers Prop-2012 WV			14,180,500		
20						
21	Pers Prop-Leased 2010 WV	21,334		1,623	22,957	
22	Pers Prop-Leased 2011 WV	10,500		2,153	7,753	
23	Pers Prop-Leased 2012 WV			8,000		
24						
25	RE & Pers Prop-2010 IL	602,611			602,611	
26	RE & Pers Prop-2011 IL	575,000		55,314	630,314	
27	RE & Pers Prop-2012 IL			630,000		
28						
29	RAIL CAR PROPERTY					
30	Prop Tax - 2010	65,429		-40,912	24,517	
31	Prop Tax - 2011	68,355		26,379	85,146	
32	Prop Tax - 2012			102,523	7,502	
33						
34	2010 LA Property Tax	-2,856		2,856		
35						
36	2009 KY Property Tax	-9,071		9,071		
37	2010 KY Property Tax	38,000		-6,885	31,115	
38	2011 KY Property Tax	38,000		-2,000	34,414	
39	2012 KY Property Tax			36,500		
40						
41	TOTAL	437,248,507	131,549	516,750,340	485,904,321	-19,160,029

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1						
2	CITY TAX - 2010 & Prior					
3	CITY TAX - 2011	-1,355,878		-589,037	-322,723	
4	CITY TAX - 2012			-223,135	1,137,837	
5	STATE LIC TAX 2011 &			625	625	
6	STATE LIC TAX 2012			4,784	4,784	
7	FED INC TAX FIN48					-1,400,221
8	STATE INC TAX FIN48	6,416,338		-4,608,286	699,236	
9						
10	STATE OF MICHIGAN:					
11	INCOME TAX 2011	-442,006		218,718	-223,288	
12	INCOME TAX 2012			28,596	223,288	
13						
14	Payroll Taxes - CCD			1,202,258	1,202,258	
15						
16	STATE OF KENTUCKY:					
17	INCOME TAX 2000			101	101	
18	INCOME TAX 2011	-62,760		563	-62,197	
19	INCOME TAX 2012			275,561	194,000	
20						
21	MISC FRANCHISE			-25	-25	
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	437,248,507	131,549	516,750,340	485,904,321	-19,160,029

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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
-14,476,251		91,930,521			1,000,056	2
2,542,114		12,667,108			5,996,031	3
121,401		163,225			40,605	4
					7,654	5
		8,233			23,016	6
						7
						8
		202,880				9
2,673,000		10,396,850				10
		5,879,061				11
						12
12,448,304		143,109,283				13
		-1,790			-86,092	14
319,342	140,000	-69			1,494,677	15
652		57,984			55,961	16
-1		-6,145,609				17
						18
						19
		-283,401			-39,854	20
480,167		844,851			89,363	21
					-1,974	22
16,654					107,710	23
454					36,847	24
						25
						26
						27
-7						28
						29
		-861,595			1,671,777	30
10,275,549		20,791,301			-7,484,752	31
-11,884		610,117				32
		-61,721				33
-14,425		7,676				34
		51,171			-2,910	35
					-2,085	36
21,049		770			143,448	37
		144,162			874	38
1,163,709		15,735,811				39
3,654,700		327,500				40
448,942,948	140,000	505,480,728			11,269,612	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
						3
		-7,090				4
		381,603			-16,059	5
201,356,948		200,347,858			-202,259,668	6
208,575,970					208,575,970	7
						8
-1,033		-4,086				9
210,434		210,434				10
						11
		-24,933				12
		-217,152				13
200,000		-83,057				14
270,700		270,700				15
						16
		7,239,356			-7,239,356	17
7,537,007		6,305,005			-6,669,701	18
14,180,500					14,180,500	19
						20
					1,623	21
4,900		4,552			-2,399	22
8,000		3,997			4,003	23
						24
						25
					55,314	26
630,000					630,000	27
						28
						29
		2,385			-43,297	30
9,588					26,379	31
95,021					102,523	32
						33
					2,856	34
						35
					9,071	36
		-1,682			-5,203	37
1,586		36,000			-38,000	38
36,500					36,500	39
						40
448,942,948	140,000	505,480,728			11,269,612	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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
		-159,206			159,206	2
-1,622,192		-2,293,552			1,704,515	3
-1,360,972		829,228			-1,052,363	4
		625				5
		4,762			22	6
-1,400,221						7
1,108,816		-4,608,286				8
						9
						10
		183,902			34,816	11
-194,692		25,842			2,754	12
						13
		1,202,258				14
						15
						16
		101				17
		8,390			-7,827	18
81,561		248,480			27,081	19
						20
		-25				21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
448,942,948	140,000	505,480,728			11,269,612	41

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) X An Original (2) __ A Resubmission	/ /	2012/Q4

FOOTNOTE DATA

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

Page 262 Line 2, Column f	23,888	Fuel Tax Credit
	(19,183,918)	NOL Carryforward/FIN 48 Reclass
	1,400,222	Tax Credit Carryforward
	(17,759,808)	

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

Page 262.2, Line 7, Column f	(1,400,221)	Reclass from Account 2360001

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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%						
4	7%						
5	10%	13,492,560			4114/4115	1,849,233	
6							
7							
8	TOTAL	13,492,560				1,849,233	
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							
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43							
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45							
46							
47							
48							

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
11,643,327	Various		5
			6
			7
11,643,327			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
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			26
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			44
			45
			46
			47
			48

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) X An Original (2) __ A Resubmission	/ /	2012/Q4

FOOTNOTE DATA

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

Remaining amortization period is 12 years.

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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	Other Deferred Credits-Non Current	1,567,500	186	1,952,500	385,000	
2						
3	Allowances	6,437	Various	786,759	906,759	126,437
4						
5	Customer Advance Receipts	13,318,342	142	162,182,318	164,425,671	15,561,695
6						
7	Deferred Rev - Pole Attachments	747,438	Various	4,747,184	5,130,403	1,130,657
8						
9	IPP - System Upgrade	2,464,505				2,464,505
10						
11	SFAS 106 - OPEB	4,353,940	926	581,714	5,563	3,777,789
12						
13	ABD - Sharyland Deferred Revenue	527,179	143, 454	527,179	542,994	542,994
14						
15	Unidentified Cash Receipts	1,075	Various	250,258	254,537	5,354
16						
17	Railroad Cars Subleased Rev	2,853	Various	307,227	318,535	14,161
18						
19	Accrued Lease Exp - Non Current	451,013	931	146,244		304,769
20						
21	Other Deferred Credits - Current	1,152,374	Various	5,341,821	4,883,526	694,079
22						
23	Contract Settlement Reserves	5,489,284				5,489,284
24						
25	Federal Mitigation Deferral (NSR)				4,623,711	4,623,711
26						
27	Customer Choice Collateral Deposit	2,794,142	232	520,000	12,882,598	15,156,740
28						
29	Def Rev Selling Price Variance	29,948	9302	8,173,641	8,283,298	139,605
30						
31	Fiber Opt Lines Sold Deferred Rev	1,337,738	451	119,858		1,217,880
32	- Amortization period - 1/2005 to					
33	12/2024					
34						
35	Legal Contingencies	3,342,000				3,342,000
36						
37	Deferred Rev - Bonus Lease Curr	1,837,913				1,837,913
38						
39	Deferred Rev - Bonus Lease NC	11,027,475	421	1,837,912		9,189,563
40						
41	GridSmart Capital Reserve		588	1,759	61,209	59,450
42						
43						
44						
45						
46						
47	TOTAL	50,451,156		187,476,374	202,703,804	65,678,586

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	353,460,058	28,154,769	4,957,087
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	353,460,058	28,154,769	4,957,087
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)	353,460,058	28,154,769	4,957,087
18	Classification of TOTAL			
19	Federal Income Tax	353,460,058	28,154,769	4,957,087
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
						376,657,740	4
							5
							6
							7
						376,657,740	8
							9
							10
							11
							12
							13
							14
							15
							16
						376,657,740	17
							18
						376,657,740	19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	1,678,755,624	212,576,515	126,535,787
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,678,755,624	212,576,515	126,535,787
6				
7	Non Utility	592,747		
8	SFAS 109/FIN 48	102,538,988		
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,781,887,359	212,576,515	126,535,787
10	Classification of TOTAL			
11	Federal Income Tax	1,781,887,359	212,576,515	126,535,787
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
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
		Various	1,529			1,764,794,823	2
							3
							4
			1,529			1,764,794,823	5
							6
	13,876			Various	1,529	580,400	7
		Various	52,334,971	Various	51,541,062	101,745,079	8
	13,876		52,336,500		51,542,591	1,867,120,302	9
							10
	13,876		52,336,500		51,542,591	1,867,120,302	11
							12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Deferred Asset Recovery Rider	60,645,875		
4	Accrued Book Pension Expense	133,547,346	11,378,032	4,590,546
5	Deferred Fuel Expense	187,472,416	8,313,190	19,996,437
6	Mark To Market Book Gain	22,879,181	21,781,912	19,889,097
7	Deferred State Income Taxes	82,799,127	14,157,293	35,123,766
8	Other	107,927,764	120,861,324	90,273,796
9	TOTAL Electric (Total of lines 3 thru 8)	595,271,709	176,491,751	169,873,642
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	94,095,227		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	689,366,936	176,491,751	169,873,642
20	Classification of TOTAL			
21	Federal Income Tax	586,154,862	162,334,458	134,749,876
22	State Income Tax	103,212,074	14,157,293	35,123,766
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 Amounts Debited to Account 410.2 (e)	CHANGES DURING YEAR Amounts Credited to Account 411.2 (f)	ADJUSTMENTS Debits Account Credited (g)	ADJUSTMENTS Debits Amount (h)	ADJUSTMENTS Credits Account Debited (i)	ADJUSTMENTS Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
6,862,213	14,294,369					53,213,719	3
						140,334,832	4
						175,789,169	5
						24,771,996	6
				Various	7,242,400	69,075,054	7
190,526	348,292			Various	2,534,840	140,892,366	8
7,052,739	14,642,661				9,777,240	604,077,136	9
							10
							11
							12
							13
							14
							15
							16
							17
133,594	100,459,487	Various	54,686,744	Various	54,997,450	-5,919,960	18
7,186,333	115,102,148		54,686,744		64,774,690	598,157,176	19
							20
7,186,333	115,102,148		44,183,927		46,159,184	507,798,886	21
			10,502,817		18,615,506	90,358,290	22
							23

NOTES (Continued)

Name of Respondent Ohio Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2012/Q4

FOOTNOTE DATA

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

This footnote applies to both current and prior year.

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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		175, 1823	7,648,825	7,648,825	
2						
3	Ohio RSP-Low Income Customer/Econ Recovery	2,520,556	232	676,321	400,000	2,244,235
4	-Docket No. 04-169-EL-UNC					
5						
6	Carry Chg-Over Recover OH TCR	542,392	431	542,392		
7	-Docket No. 05-1194-EL-UNC					
8						
9	IGCC Pre-Construction Costs Net Recovery	3,448,543	1823	38,982	76,193	3,485,754
10	-Docket No. 05-376-EL-UNC					
11						
12	IGCC Over-Recovered Interest	747,791			177,316	925,107
13	-Docket No. 05-376-EL-UNC					
14						
15	DSM Over Recovery	19,124,332	Various	43,287,925	36,759,173	12,595,580
16	- Demand Side Management					
17	- Ohio ESP - Case No. 08-918-EL-SSO					
18	- Ohio ESP - Case No. 11-346-EL-SSO					
19	- Ohio ESP - Case No. 11-348-EL-SSO					
20	- Ohio ESP - Case No. 11-349-EL-AAM					
21	- Ohio ESP - Case No. 11-350-EL-AAM					
22						
23	Over-Recovered gSMART Misc Dist Expense	9,902,262	588	1,339,035	3,153,153	11,716,380
24	- Ohio ESP - Case No. 08-918-EL-SSO					
25						
26	Over-Recovered gSMART Debt Carrying Charge	(1,452,339)	1823	4,389,639	1,452,339	-4,389,639
27	- Ohio ESP - Case No. 08-918-EL-SSO					
28						
29	Over-Recovered gSMART Equity Carrying Charge	502,419	1823	502,419	1,723,018	1,723,018
30	- Ohio ESP - Case No. 08-918-EL-SSO					
31						
32	Over-Recovered gSMART Depr/A&G Expense	(1,448,691)	1823	5,587,206	1,448,691	-5,587,206
33	- Ohio ESP - Case No. 08-918-EL-SSO					
34						
35	GridSMART Reserve				38,585	38,585
36	- Case No. 12-509-EL-RDR					
37						
38						
39						
40						
41	TOTAL	38,553,823		99,401,152	100,309,461	39,462,132

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Over-Recovery EDR Deferral	2,422,199	555	2,422,379	180	
2	- EDR - Economic Development Rider					
3	- Case No. 09-119-EL-AEC					
4	- Case No. 09-516-EL-AEC					
5	- Case No. 08-884-EL-AEC					
6	- Case No. 10-3066-EL-AEC					
7						
8	EDR-Carrying Charge Over-Recovery	6,419	1823	19,583	13,164	
9	- EDR - Economic Development Rider					
10	- Case No. 09-119-EL-AEC					
11	- Case No. 09-516-EL-AEC					
12	- Case No. 08-884-EL-AEC					
13	- Case No. 10-3066-EL-AEC					
14						
15	Over-Recovery Monogahela Power Term	215,639	4073	16	26	215,649
16	- Case No. 05-765-EL-UNC					
17						
18	SFAS 109 Deferred FIT	2,022,301	Various	972,503	596,781	1,646,579
19						
20	Over-Recovered Fuel Costs - OH		501	21,995,065	34,499,999	12,504,934
21	- Ohio ESP - Case No. 08-918-EL-SSO					
22	- Ohio ESP - Case No. 08-917-EL-SSO					
23						
24	Over-Recovery AER Costs - OH		557	35,784	2,378,940	2,343,156
25	- Case No. 11-346-EL-SSO					
26	- Case No. 11-348-EL-SSO					
27	- Case No. 11-349-EL-AAM					
28	- Case No. 11-350-EL-AAM					
29						
30	Over-Recovered Market T Rider		Various	8,034,709	8,034,709	
31	- MTR - Market Transition Rider					
32	- Case No. 11-346-EL-SSO					
33	- Case No. 11-348-EL-SSO					
34						
35	Over-Recovered Dist Invest Rider		Various	1,908,369	1,908,369	
36	- DIR - Distribution Investment Rider					
37	- Case No. 11-346-EL-SSO					
38	- Case No. 11-348-EL-SSO					
39						
40						
41	TOTAL	38,553,823		99,401,152	100,309,461	39,462,132

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,636,808,400	1,680,179,478
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	945,233,021	1,077,742,471
5	Large (or Ind.) (See Instr. 4)	745,568,844	983,382,876
6	(444) Public Street and Highway Lighting	18,079,470	17,649,264
7	(445) Other Sales to Public Authorities	33,169	64,879
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	3,345,722,904	3,759,018,968
11	(447) Sales for Resale	1,436,992,525	1,594,320,264
12	TOTAL Sales of Electricity	4,782,715,429	5,353,339,232
13	(Less) (449.1) Provision for Rate Refunds	2,577,000	-6,034,599
14	TOTAL Revenues Net of Prov. for Refunds	4,780,138,429	5,359,373,831
15	Other Operating Revenues		
16	(450) Forfeited Discounts	3,208,602	3,592,449
17	(451) Miscellaneous Service Revenues	7,681,845	5,338,704
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	29,427,587	30,668,766
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	971,992	-58,783
22	(456.1) Revenues from Transmission of Electricity of Others	100,193,603	56,854,297
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	141,483,629	96,395,433
27	TOTAL Electric Operating Revenues	4,921,622,058	5,455,769,264

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
12,413,637	14,950,412	1,273,361	1,273,589	2
				3
7,037,849	10,726,112	173,948	173,091	4
11,352,291	17,698,421	10,274	10,377	5
92,832	116,208	2,784	2,792	6
396	911	26	26	7
				8
				9
30,897,005	43,492,064	1,460,393	1,459,875	10
32,625,825	30,969,182	97	116	11
63,522,830	74,461,246	1,460,490	1,459,991	12
				13
63,522,830	74,461,246	1,460,490	1,459,991	14

Line 12, column (b) includes $ 31,263,358 of unbilled revenues.
Line 12, column (d) includes -37,253 MWH relating to unbilled revenues

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	/ /	2012/Q4

FOOTNOTE DATA

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

Detail of Unmetered Sales:

	Revenue	MWH	Average Customers
Residential	6,407,048	24,542	36,628
Commercial	17,481,787	84,856	26,883
Industrial	1,546,786	8,347	1,578
Public Street Lighting	16,034,825	99,375	1,476
	41,470,446	217,120	66,565

Total Sales to Ultimate Consumers included $395,352,810 of Operating Revenue for distribution services provided to Open Acess Customers. Megawatt hours delivered to Open Acess Customers were 16,007,911 and are excluded from the reported megawatt hours sold on Pg 301 (d).

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

Total Sales to Ultimate Consumers include $101,381,440 of Operating Revenues for distribution services provided to Open Acess Customers. Megawatt hours delivered to Open Access Customers were 4,935,606 and are excluded from the reported megawatt hours sold on Pg 301(e).

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

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

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

Description	YTD - 2012
Assoc. Business Development	2,460,269
Off System Sales FTR Mark to Mkt	885,534
Oth Elect Rev-Transmission-Affil	267,126
Financial Trading Rev. Unrealized	(2,562,494)
All Other (under $250,000 each)	(78,443)
Total	971,992

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
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16					
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38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2012/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440-Residential					
2	GS-1 Gen Svc Fixed	15	1,796	1	15,000	0.1197
3	GS-2 Gen Svc Low	20	2,566	1	20,000	0.1283
4	RR Residential Regular	5,936,826	734,246,642	473,117	12,548	0.1237
5	RR-1 Residential Low Usage	630,081	80,806,353	132,653	4,750	0.1282
6	RS Residential Service	5,985,701	691,971,667	501,920	11,926	0.1156
7	OL Outdoor Lighting	23,618	6,244,422			0.2644
8	OAD RR Residential Regular	738,307	37,402,133	62,471	11,818	0.0507
9	OAD RS Residential Service	1,172,299	54,939,425	103,198	11,360	0.0469
10	OAD OL Outdoor Lighting	924	162,626			0.1760
11	OAD - MWH Sold Adjustment	-2,071,752				
12	Subtotal-Billed	12,416,039	1,605,777,630	1,273,361	9,751	0.1293
13	Net Unbilled	-2,402	31,030,770			-12.9187
14	Total-Residential	12,413,637	1,636,808,400	1,273,361	9,749	0.1319
15						
16	442-Commercial					
17	EHG Electric Heating General	19,274	1,770,167	444	43,410	0.0918
18	GS-1 Gen Svc Fixed	590,852	79,138,749	101,916	5,797	0.1339
19	GS-2 Gen Svc Low	2,237,896	282,379,140	35,989	62,183	0.1262
20	GS-3 Gen Svc Medium	3,724,468	342,028,353	5,873	634,168	0.0918
21	GS-4 Gen Svc Large	581,947	32,800,917	6	96,991,167	0.0564
22	GS-TOD Gen Svc-Time of Day	74,535	7,185,330	699	106,631	0.0964
23	LS Special Contract	-9	-47,216			5.2462
24	OL Outdoor Lighting	73,447	16,346,819	1	73,447,000	0.2226
25	PB Phone Booth	9	1,576	6	1,500	0.1751
26	PS School Service	13,570	1,330,079	71	191,127	0.0980
27	SB Stand by Service		113,006	1		
28	SL Street Lighting	1,032	88,532	3	344,000	0.0858
29	TL Traffic Light	2	-435	1	2,000	-0.2175
30	TV Television Cable	5,676	638,969	133	42,677	0.1126
31	OAD GS-1 Gen Svc Fixed	79,278	3,847,461	8,998	8,811	0.0485
32	OAD GS-2 Gen Svc Low	1,600,398	59,897,817	15,051	106,332	0.0374
33	OAD GS-3 Gen Svc Medium	4,809,084	112,113,928	4,651	1,033,989	0.0233
34	OAD GS-4 Gen Svc Large	311,063	1,191,845	7	44,437,571	0.0038
35	OAD OL Outdoor Lighting	5,872	788,213			0.1342
36	OAD PB Phone Booth	10	780	6	1,667	0.0780
37	OAD PS School Service	20,536	643,223	83	247,422	0.0313
38	OAD SL Street Lighting	3,309	100,267	1	3,309,000	0.0303
39	OAD TV Television Cable	108	3,773	1	108,000	0.0349
40	OAD - MWH Sold Adjustment	-7,138,254				
41	TOTAL Billed	30,934,258	3,314,459,546	1,460,393	21,182	0.1071
42	Total Unbilled Rev.(See Instr. 6)	-37,253	31,263,358	0	0	-0.8392
43	TOTAL	30,897,005	3,345,722,904	1,460,393	21,157	0.1083

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Net Estimated Billings	44,267	-112,397	7	6,323,857	-0.0025
2	Subtotal-Billed	7,058,370	942,248,896	173,948	40,577	0.1335
3	Net Unbilled	-20,521	2,984,125			-0.1454
4	Total-Commercial	7,037,849	945,233,021	173,948	40,459	0.1343
5						
6	442-Industrial					
7	EHG Electric Heating General	869	91,436	14	62,071	0.1052
8	GS-1 Gen Svc Fixed	19,941	3,094,220	4,969	4,013	0.1552
9	GS-2 Gen Svc Low	597,515	68,422,680	2,301	259,676	0.1145
10	GS-3 Gen Svc Medium	2,039,746	167,525,316	556	3,668,608	0.0821
11	GS-4 Gen Svc Large	5,829,199	265,949,880	31	188,038,677	0.0456
12	GS-TOD Gen Svc-Time of Day	5,937	597,101	24	247,375	0.1006
13	IR Interruptible Service	3,071,154	153,533,414	13	236,242,615	0.0500
14	OL Outdoor Lighting	7,086	1,417,961			0.2001
15	OAD EHG Electric Heating General	213	9,459	2	106,500	0.0444
16	OAD GS-1 Gen Svc Fixed	3,894	200,530	528	7,375	0.0515
17	OAD GS-2 Gen Svc Low	684,184	23,502,113	1,300	526,295	0.0344
18	OAD GS-3 Gen Svc Medium	2,534,239	50,663,020	505	5,018,295	0.0200
19	OAD GS-4 Gen Svc Large	3,243,151	12,794,185	30	108,105,033	0.0039
20	OAD OL Outdoor Lighting	559	61,240			0.1096
21	OAD - MWH Sold Adjustment	-6,771,548				
22	Company use - MWH Adj	-1,166	-118,887			0.1020
23	Net Estimated Billings	101,812	607,202	1	101,812,000	0.0060
24	Subtotal-Billed	11,366,785	748,350,870	10,274	1,106,364	0.0658
25	Net Unbilled	-14,494	-2,782,026			0.1919
26	Total-Industrial	11,352,291	745,568,844	10,274	1,104,953	0.0657
27						
28	444-Street & Highway Lighting					
29	GS-1 Gen Svc Fixed	2,967	467,652	922	3,218	0.1576
30	GS-2 Gen Svc Low	1,227	135,075	15	81,800	0.1101
31	GS-3 Gen Svc Medium	878	75,203	1	878,000	0.0857
32	OL Outdoor Lighting	207	45,661			0.2206
33	SL Street Lighting	77,718	14,170,437	1,104	70,397	0.1823
34	TL Traffic Light	10,590	1,157,799	71	149,155	0.1093
35	OAD GS-1 Gen Svc Fixed	1,925	144,371	523	3,681	0.0750
36	OAD GS-2 Gen Svc Low	1,023	37,535	14	73,071	0.0367
37	OAD GS-3 Gen Svc Medium	185	5,577	1	185,000	0.0301
38	OAD OL Outdoor Lighting	16	4,076			0.2548
39	OAD SL Street Lighting	21,071	1,760,537	118	178,568	0.0836
40	OAD TL Traffic Light	1,188	43,199	15	79,200	0.0364
41	TOTAL Billed	30,934,258	3,314,459,546	1,460,393	21,182	0.1071
42	Total Unbilled Rev.(See Instr. 6)	-37,253	31,263,358	0	0	-0.8392
43	TOTAL	30,897,005	3,345,722,904	1,460,393	21,157	0.1083

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	OAD - MWH Sold Adjustment	-26,357				
2	Subtotal-Billed	92,638	18,047,122	2,784	33,275	0.1948
3	Net Unbilled	194	32,348			0.1667
4	Total-St & Highway Lighting	92,832	18,079,470	2,784	33,345	0.1948
5						
6	A/C 445 Pub Authorities - Other					
7	FP Flood Pumping	426	35,028	26	16,385	0.0822
8	Subtotal-Billed	426	35,028	26	16,385	0.0822
9	Net Unbilled	-30	-1,859			0.0620
10	Total-Pub Authorities - Other	396	33,169	26	15,231	0.0838
11						
12	Fuel Adj Clause - Footnote					
13						
14						
15						
16						
17						
18						
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20						
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40						
41	TOTAL Billed	30,934,258	3,314,459,546	1,460,393	21,182	0.1071
42	Total Unbilled Rev.(See Instr. 6)	-37,253	31,263,358	0	0	-0.8392
43	TOTAL	30,897,005	3,345,722,904	1,460,393	21,157	0.1083

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) X An Original (2) __ A Resubmission	/ /	2012/Q4

FOOTNOTE DATA

Schedule Page: 304.2 Line No.: 12 Column: a

Fuel Adjustment Clause - Total Estimated Additional Revenues Billed and Unbilled

440-Residential	Revenues
GS-1 Gen Svc Fixed	567
GS-2 Gen Svc Low	630
RR Residential Regular	235,010,801
RR-1 Residential Low Usage	24,072,637
RS Residential Service	208,528,361
OL Outdoor Lighting	872,037
OAD Residential Regular	11
OAD Residential Service	(8)
Subtotal-Billed	**468,485,036**
Net Unbilled	(5,416,808)
Total 440-Residential	**463,068,228**

442-Commerical	Revenues
EHG Electric Heating General	584,693
GS-1 Gen Svc Fixed	19,729,608
GS-2 Gen Svc Low	82,205,917
GS-3 Gen Svc Medium	137,693,716
GS-4 Gen Svc Large	22,098,116
GS-TOD Gen Svc-Time of Day	2,590,123
LS Special Contract	(319)
OL Outdoor Lighting	2,743,410
PB Phone Booth	365
PS School Service	472,396
SB Stand by Service	604
SL Street Lighting	41,049

442-Industrial	Revenues
EHG Electric Heating General	30,333
GS-1 Gen Svc Fixed	724,110
GS-2 Gen Svc Low	20,650,357
GS-3 Gen Svc Medium	71,103,287
GS-4 Gen Svc Large	203,459,330
GS-TOD Gen Svc-Time of Day	206,004
OAD GS-2 Gen Svc Low	349
OAD GS-4 Gen Svc Large	3,329,479
IR Interruptible Service	97,267,018
OL Outdoor Lighting	281,318
Net Estimated Billings	(346,843)
Subtotal-Billed	**396,704,742**
Net Unbilled	(7,450,971)
Total 442-Industrial	**389,253,771**

444-Street & Highway Lighting	Revenues
GS-1 Gen Svc Fixed	722,157
GS-2 Gen Svc Low	297,889
OAD GS-1 Gen Svc Fixed	1,570,458
OAD GS-2 Gen Svc Low	838,120
Subtotal-Billed	**3,428,624**
Net Unbilled	(19,888)
Total 444-Street & Highway Lighting	**3,408,736**

445-Pub Authorities - Other

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	/ /	2012/Q4

FOOTNOTE DATA

Revenues

TL Traffic Light	94	FP Flood Pumping	14,939
TV Television Cable	225,228	**Subtotal-Billed**	**14,939**
OAD GS-2 Gen Svc Low	221	Net Unbilled	(1,234)
Net Estimated Billings	(316,464)	**Total 445-Pub Authorities - Other**	**13,705**
Subtotal-Billed	**268,068,757**		
Net Unbilled	(7,903,440)	**Total Billed**	**1,136,702,098**
Total 442-Commercial	**260,165,317**	**Total Unbilled**	**(20,792,341)**
		Total	**1,115,909,757**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	Average Monthly CP Demand (f)
1	Ohio Edison - 217	RQ	OPCO-99			
2	Ohio Edison - 244	RQ	OPCO-99			
3	Wheeling Power	RQ	OPCO-18			
4	AEP Service Corporation	OS	20			
5	AEP Service Corporation	OS	23			
6	Advan Promotions Inc.	OS	Note 1			
7	Allegheny Electric Cooperative	OS	Note 1			
8	ALLETE, Inc. dba Minnesota Pwr	OS	Note 1			
9	Ameren Energy Marketing	OS	Note 1			
10	AmerenCILCO, CIPS, Ameren IP	OS	Note 1			
11	American Municipal Power-Ohio	OS	Note 1			
12	American PwerNet Management	OS	Note 1			
13	Associated Elect Cooperative	OS	Note 1			
14	B.P. Energy Company	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Barclays Bank PLC	OS	Note 1			
2	Beech Ridge Energy LLC	OS	Note 1			
3	BP AMOCO	OS	Note 1			
4	Buckeye Rural Electric Admin	OS	Note 1			
5	California Power Exchange	OS	Note 1			
6	Calpine Power Service Company	OS	Note 1			
7	Carolina Power & Light	OS	Note 1			
8	Citigroup Energy, Inc.	OS	Note 1			
9	Citizens Elect Co & Wellsborough	OS	Note 1			
10	City of Batavia	OS	Note 1			
11	City of Columbus	OS	Note 1			
12	City of Croswell, MI	OS	Note 1			
13	City of Dowagiac, MI	OS	Note 1			
14	City of Kirkwood, Missouri	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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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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.
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LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
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)	Average Monthly CP Demand (f)
1	City of Medford	OS	Note 1			
2	City of Shelby	OS	Note 1			
3	City of Westerville	OS	Note 1			
4	Cleveland Public Power	OS	Note 1			
5	Cleveland Toledo OH PA Electric	OS	Note 1			
6	Commonwealth Edison Company	OS	Note 1			
7	Conoco, Inc.	OS	Note 1			
8	Constellation Engy Commodities	OS	Note 1			
9	Cook Inlet Energy Supply LP	OS	Note 1			
10	Dairyland Power Cooperative	OS	Note 1			
11	DB Energy Trading LLC	OS	Note 1			
12	Delaware Electric Municipal Co.	OS	Note 1			
13	Dominion Equipment Inc.	OS	Note 1			
14	DP&L Power Services	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 long-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.
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LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	DTE Energy Trading Inc.	OS	Note 1			
2	Duke Energy Carolinas, LLC	OS	Note 1			
3	Duke Energy Indiana, Inc.	OS	Note 1			
4	Duke Energy Ohio, Inc.	OS	Note 1			
5	East KY Power Co-Op Power Mktg	OS	Note 1			
6	Easton Utilities	OS	Note 1			
7	EDF Trading North America LLC	OS	Note 1			
8	Edison Mission Mktg & Trading	OS	Note 1			
9	Endure Energy, LLC	OS	Note 1			
10	Energy America, LLC	OS	Note 1			
11	Eng Mktg, div of Amerada Hess	OS	Note 1			
12	Entergy Power Serv	OS	Note 1			
13	Exelon Generation - Power Team	OS	Note 1			
14	FirstEnergy Trading Services	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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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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.
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LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (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	GBC Metals, LLC	OS	Note 1			
2	Great River Energy	OS	Note 1			
3	Harrison Rural Electrification	OS	Note 1			
4	Hoosier Power Market	OS	Note 1			
5	Illinois Municipal Elec Agency	OS	Note 1			
6	Indiana Municipal Power Agency	OS	Note 1			
7	Indianapolis Power & Light	OS	Note 1			
8	Integrys Energy Serices, Inc.	OS	Note 1			
9	Interstate Gas Supply, Inc.	OS	Note 1			
10	Interstate Power & Light Co.	OS	Note 1			
11	J ARON & Company	OS	Note 1			
12	JP Morgan Ventures Energy Corp.	OS	Note 1			
13	Kansas City Power & Light Co.	OS	Note 1			
14	Kentucky Municipal Power Agncy	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	Average Monthly CP Demand (f)
1	L&P Electric, Inc.	OS	Note 1			
2	Letterkenny Industril Dev Auth	OS	Note 1			
3	LG&E Utilities Power Sales	OS	Note 1			
4	Michigan Public Power Agency	OS	Note 1			
5	MidAmerican Energy	OS	Note 1			
6	Midwest ISO	OS	Note 1			
7	Mizuho Securities USA Inc.	OS	Note 1			
8	Mogran Stanley Capt.	OS	Note 1			
9	NC Electric Membership Corp.	OS	Note 1			
10	NextEra Energy Power Mktg LLC	OS	Note 1			
11	No Carolina Muni Pwr Agency #1	OS	Note 1			
12	Noble Americas Gas and Power Corp.	OS	Note 1			
13	NRG Power Marketing, Inc	OS	Note 1			
14	NSP Energy Marketing	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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).
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Old Dominion Elec.	OS	Note 1			
2	Otter Tail Power Company	OS	Note 1			
3	OVEC Power Scheduling	OS	Note 1			
4	Paribas	OS	Note 1			
5	Peco Energy Company	OS	Note 1			
6	PEPCO Services, Inc.	OS	Note 1			
7	PJM Environmental Info Sys Inc.	OS	Note 1			
8	PJM Interconnection	OS	Note 1			
9	Potomas Electrc Power Company	OS	Note 1			
10	PP&L Energy Plus Co.	OS	Note 1			
11	PPL Electric Utilities Corp.	OS	Note 1			
12	Prairie Power, Inc.	OS	Note 1			
13	Prairieland Energy Incorporate	OS	Note 1			
14	PSEG Energy Resources & Trade	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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).
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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)	Average Monthly CP Demand (f)
1	Quasar Energy Power Marketing	OS	Note 1			
2	Sempra Energy Solutions, LLC	OS	Note 1			
3	Shell Energy N America (US) LP	OS	Note 1			
4	Southern Maryland Elec Coop Inc.	OS	Note 1			
5	Southern Company	OS	Note 1			
6	Southern Illinois Power Co-Op	OS	Note 1			
7	Tenaska Power Services Company	OS	Note 1			
8	The Borough of Pitcairn, PA	OS	Note 1			
9	The Energy Authority	OS	Note 1			
10	The Potomac Edison Company	OS	Note 1			
11	Timber Canyon	OS	Note 1			
12	Town of Berlin, Maryland	OS	Note 1			
13	Town of Hagerstown, Indiana	OS	Note 1			
14	TVA Bulk Power Trading	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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).
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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	UBS AG, London Branch	OS	Note 1			
2	UBS Securities LLC	OS	Note 1			
3	Union Electric Company	OS	Note 1			
4	Union Power Partners	OS	Note 1			
5	Village of Bethel Ohio	OS	Note 1			
6	Village of Glouster	OS	Note 1			
7	Village of Hamersville, Ohio	OS	Note 1			
8	Village of Ripley, Ohio	OS	Note 1			
9	Village of Sebewaing, MI	OS	Note 1			
10	Virginia City Hybrid Energy Center	OS	Note 1			
11	Wabash Valley Power Assn Inc.	OS	Note 1			
12	Washington Gas Energy Services	OS	Note 1			
13	West Penn Power Company	OS	Note 1			
14	Westar Energy Inc.	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Wisconsin Power & Light	OS	Note 1			
2	Wolverine Power Supply Coop	OS	Note 1			
3	ADJUSTMENT	OS	Note 1			
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
7,458	405,302	248,133		653,435	1
500	35,326	16,728		52,054	2
2,588,175	48,042,888	87,370,519	729,228	136,142,635	3
		-70,159		-70,159	4
15,227,113	207,179,550	436,760,230		643,939,780	5
		-15,384		-15,384	6
211,247		11,496,220		11,496,220	7
-12,810		-313,760		-313,760	8
-60,153		-2,471,476		-2,471,476	9
7,182		297,582		297,582	10
153,526	1,900,597	9,042,701		10,943,298	11
34,294		1,429,866		1,429,866	12
-3,580		-95,726		-95,726	13
34,813		1,938,897		1,938,897	14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	**293,654,513**	**1,043,983,082**	**99,354,930**	**1,436,992,525**	

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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.
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MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
118,862		4,707,756		4,707,756	1
		-106,303		-106,303	2
		285,728		285,728	3
3,485,407	24,697,334	136,153,633		160,850,967	4
		1,911		1,911	5
-2,104		-49,196		-49,196	6
453		14,997		14,997	7
		114,172		114,172	8
4,371		230,342		230,342	9
11,269		423,143		423,143	10
376,782		24,961,483		24,961,483	11
17,812		863,579		863,579	12
		2,111		2,111	13
	214			214	14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	**293,654,513**	**1,043,983,082**	**99,354,930**	**1,436,992,525**	

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Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SALES FOR RESALE (Account 447) (Continued)

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MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
55,011		3,191,008		3,191,008	1
15,439		1,102,174		1,102,174	2
119,880		10,047,967		10,047,967	3
85,486		4,462,432		4,462,432	4
	692,715	-873		691,842	5
160,812		6,829,114		6,829,114	6
		397,543		397,543	7
-3,829		-1,474,680		-1,474,680	8
		233,762		233,762	9
-1,886		110,373		110,373	10
209,125		7,760,222		7,760,222	11
78,913		5,129,334		5,129,334	12
14,348		568,189		568,189	13
		-502,114		-502,114	14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	**293,654,513**	**1,043,983,082**	**99,354,930**	**1,436,992,525**	

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SALES FOR RESALE (Account 447) (Continued)

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MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
	9,867	-22,801		-12,934	1
128		-2,720		-2,720	2
		810,157		810,157	3
156,517		7,793,199		7,793,199	4
189,388		7,272,650		7,272,650	5
22,727		1,233,255		1,233,255	6
308,270		15,280,761		15,280,761	7
	294,546	51,501		346,047	8
		-5,148		-5,148	9
		1,728,575		1,728,575	10
		2,307,814		2,307,814	11
-1,303		-57,090		-57,090	12
-22,016		-21,485,130		-21,485,130	13
975,025		56,027,065		56,027,065	14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	293,654,513	1,043,983,082	99,354,930	1,436,992,525	

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SALES FOR RESALE (Account 447) (Continued)

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MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		42,802		42,802	1
		-72,316		-72,316	2
41,026		3,292,764		3,292,764	3
9,438		248,013		248,013	4
208		14,811		14,811	5
	10,371	93,608		103,979	6
	20,816			20,816	7
		353,265		353,265	8
		-5,426		-5,426	9
32,550		724,226		724,226	10
1,213,129		34,894,522		34,894,522	11
221,161		-2,824,316		-2,824,316	12
-285		-6,886		-6,886	13
29,613		1,716,752		1,716,752	14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	**293,654,513**	**1,043,983,082**	**99,354,930**	**1,436,992,525**	

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SALES FOR RESALE (Account 447) (Continued)

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13,699		491,572		491,572	1
32,613		2,181,325		2,181,325	2
193		5,987		5,987	3
54,057		3,287,338		3,287,338	4
		-1,516,745		-1,516,745	5
-1,228,310		-38,396,095		-38,396,095	6
		4,713,705		4,713,705	7
12,371		-532,846		-532,846	8
939,521		35,449,609		35,449,609	9
4,299		1,572,613		1,572,613	10
70		2,113		2,113	11
		122,429		122,429	12
-55,598		-1,534,191		-1,534,191	13
		378,758		378,758	14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	**293,654,513**	**1,043,983,082**	**99,354,930**	**1,436,992,525**	

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
141,049		6,892,919		6,892,919	1
		11,290		11,290	2
44,419		1,574,831		1,574,831	3
		9,847		9,847	4
13,904		1,010,434		1,010,434	5
23,675		1,248,796		1,248,796	6
		-295		-295	7
5,039,290	10,360,480	127,193,097	98,625,702	236,179,279	8
127,885		9,809,009		9,809,009	9
		-3,721,617		-3,721,617	10
29,284		2,036,170		2,036,170	11
42,093		2,777,739		2,777,739	12
79,412	-74	2,570,276		2,570,202	13
62,855		1,888,096		1,888,096	14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	**293,654,513**	**1,043,983,082**	**99,354,930**	**1,436,992,525**	

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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,line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
-1,370		-36,189		-36,189	1
		3,308,322		3,308,322	2
68		3,434		3,434	3
2,238		126,466		126,466	4
7,257		214,580		214,580	5
7,158		236,725		236,725	6
-171		-3,554		-3,554	7
5,579		239,305		239,305	8
6,713		245,054		245,054	9
666		39,116		39,116	10
		-15,384		-15,384	11
18,192		1,150,993		1,150,993	12
10,361		632,521		632,521	13
647		42,257		42,257	14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	**293,654,513**	**1,043,983,082**	**99,354,930**	**1,436,992,525**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.
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5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		-318,380		-318,380	1
		-24,431,461		-24,431,461	2
		-934,120		-934,120	3
-3,266		-68,113		-68,113	4
12,048		624,958		624,958	5
718		145,676		145,676	6
2,231		123,500		123,500	7
8,212		423,098		423,098	8
19,543		935,832		935,832	9
		465,107		465,107	10
		343,931		343,931	11
458,981		22,592,324		22,592,324	12
-169		-9,004		-9,004	13
42,302		784,442		784,442	14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	**293,654,513**	**1,043,983,082**	**99,354,930**	**1,436,992,525**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)
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6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
30,428		1,105,168		1,105,168	1
511,186	4,581	17,827,221		17,831,802	2
		-1,832,992		-1,832,992	3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	**293,654,513**	**1,043,983,082**	**99,354,930**	**1,436,992,525**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

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

AEP Affiliate.

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

Amount represents transmission service and related charges.

Schedule Page: 310 Line No.: 4 Column: a

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

Schedule Page: 310 Line No.: 5 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 Line No.: 6 Column: c

NOTE 1: FERC Electric Tariff, First Revised Volumn No. 5.

Schedule Page: 310.6 Line No.: 8 Column: j

Amount represents capacity revenues from Competitive Retail Electric Service (CRES) providers.

Schedule Page: 310.9 Line No.: 3 Column: a

Reclass between 447 and 555 accounts to incorporate certain trading/marketing activity. The amounts represented on Page 310-311 and 326-327 are equal and off-setting.

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	21,095,125	24,252,372
5	(501) Fuel	1,342,546,762	1,420,996,722
6	(502) Steam Expenses	119,662,156	143,753,090
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,963,159	3,386,294
10	(506) Miscellaneous Steam Power Expenses	64,288,991	167,633,071
11	(507) Rents	13,606	33,333
12	(509) Allowances	14,413,222	48,784,433
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	1,564,983,021	1,808,839,315
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	16,902,347	14,894,516
16	(511) Maintenance of Structures	10,765,085	13,663,576
17	(512) Maintenance of Boiler Plant	119,000,715	195,397,381
18	(513) Maintenance of Electric Plant	26,375,615	35,698,220
19	(514) Maintenance of Miscellaneous Steam Plant	13,156,766	14,561,150
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	186,200,528	274,214,843
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	1,751,183,549	2,083,054,158
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	69,431	29,969
45	(536) Water for Power	29,229	25,443
46	(537) Hydraulic Expenses	1,347	3,885
47	(538) Electric Expenses		889
48	(539) Miscellaneous Hydraulic Power Generation Expenses	192,234	171,033
49	(540) Rents	41,666	50,000
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	333,907	281,219
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	952	4,918
54	(542) Maintenance of Structures	123,198	20,668
55	(543) Maintenance of Reservoirs, Dams, and Waterways	28,520	11,606
56	(544) Maintenance of Electric Plant	326,918	535,393
57	(545) Maintenance of Miscellaneous Hydraulic Plant	59,652	250,998
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	539,240	823,583
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	873,147	1,104,802

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	172,178	169,004
63	(547) Fuel	3,586,443	2,940,639
64	(548) Generation Expenses	161,022	214,004
65	(549) Miscellaneous Other Power Generation Expenses	332,805	304,382
66	(550) Rents	34,963	51,442
67	TOTAL Operation (Enter Total of lines 62 thru 66)	4,287,411	3,679,471
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	71,720	73,647
70	(552) Maintenance of Structures	14,638	11,734
71	(553) Maintenance of Generating and Electric Plant	633,617	982,596
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	123,871	128,811
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	843,846	1,196,788
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	5,131,257	4,876,259
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	642,150,858	892,250,028
77	(556) System Control and Load Dispatching	2,410,516	2,904,180
78	(557) Other Expenses	23,375,679	20,171,331
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	667,937,053	915,325,539
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,425,125,006	3,004,360,758
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	5,005,275	4,278,466
84			
85	(561.1) Load Dispatch-Reliability	34,962	36,600
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	5,013,509	4,932,726
87	(561.3) Load Dispatch-Transmission Service and Scheduling	-480	35
88	(561.4) Scheduling, System Control and Dispatch Services	8,170,124	7,287,434
89	(561.5) Reliability, Planning and Standards Development	798,616	723,997
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	1,734,018	1,677,972
93	(562) Station Expenses	1,440,420	1,530,359
94	(563) Overhead Lines Expenses	180,095	447,896
95	(564) Underground Lines Expenses	489	230
96	(565) Transmission of Electricity by Others	22,667,784	33,282,508
97	(566) Miscellaneous Transmission Expenses	-13,848,194	-23,555,771
98	(567) Rents	259,015	281,096
99	TOTAL Operation (Enter Total of lines 83 thru 98)	31,455,633	30,923,548
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	278,172	299,190
102	(569) Maintenance of Structures	150,852	199,131
103	(569.1) Maintenance of Computer Hardware	214,439	271,987
104	(569.2) Maintenance of Computer Software	1,100,968	1,287,033
105	(569.3) Maintenance of Communication Equipment	398,959	828,092
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	5,365,972	6,675,061
108	(571) Maintenance of Overhead Lines	12,591,310	8,682,174
109	(572) Maintenance of Underground Lines	330,496	394,118
110	(573) Maintenance of Miscellaneous Transmission Plant	952,585	494
111	TOTAL Maintenance (Total of lines 101 thru 110)	21,383,753	18,637,280
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	52,839,386	49,560,828

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Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	8,466,532	7,630,463
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	8,466,532	7,630,463
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardwere		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	8,466,532	7,630,463
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	6,450,153	5,352,042
135	(581) Load Dispatching	16,374	12,251
136	(582) Station Expenses	1,963,394	2,151,550
137	(583) Overhead Line Expenses	681,367	2,097,553
138	(584) Underground Line Expenses	1,447,991	3,281,619
139	(585) Street Lighting and Signal System Expenses	181,753	203,799
140	(586) Meter Expenses	2,141,871	2,783,267
141	(587) Customer Installations Expenses	120,422	362,021
142	(588) Miscellaneous Expenses	34,940,338	27,907,214
143	(589) Rents	5,021,728	6,366,649
144	TOTAL Operation (Enter Total of lines 134 thru 143)	52,965,391	50,517,965
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	666,635	687,274
147	(591) Maintenance of Structures	410,644	479,449
148	(592) Maintenance of Station Equipment	5,004,560	5,826,242
149	(593) Maintenance of Overhead Lines	87,464,618	75,964,519
150	(594) Maintenance of Underground Lines	4,875,786	3,839,105
151	(595) Maintenance of Line Transformers	1,245,315	1,137,785
152	(596) Maintenance of Street Lighting and Signal Systems	414,846	341,454
153	(597) Maintenance of Meters	516,626	568,320
154	(598) Maintenance of Miscellaneous Distribution Plant	2,000,287	2,383,191
155	TOTAL Maintenance (Total of lines 146 thru 154)	102,599,317	91,227,339
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	155,564,708	141,745,304
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,612,514	2,220,151
160	(902) Meter Reading Expenses	7,836,431	7,519,338
161	(903) Customer Records and Collection Expenses	44,845,230	46,627,577
162	(904) Uncollectible Accounts	87,397,194	83,563,951
163	(905) Miscellaneous Customer Accounts Expenses	6,113,008	267,744
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	147,804,377	140,198,761

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	4,180,177	6,783,352
168	(908) Customer Assistance Expenses	85,852,106	89,082,204
169	(909) Informational and Instructional Expenses	1,383	47,388
170	(910) Miscellaneous Customer Service and Informational Expenses	26,087	75,490
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	90,059,753	95,988,434
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	1,490,392	524,434
175	(912) Demonstrating and Selling Expenses	21	1,184
176	(913) Advertising Expenses	88,618	
177	(916) Miscellaneous Sales Expenses	24,418	26,170
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	1,603,449	551,788
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	42,516,721	42,022,460
182	(921) Office Supplies and Expenses	3,439,653	5,292,614
183	(Less) (922) Administrative Expenses Transferred-Credit	8,643,861	7,184,485
184	(923) Outside Services Employed	34,020,334	38,432,096
185	(924) Property Insurance	6,727,215	8,402,053
186	(925) Injuries and Damages	10,295,892	13,989,856
187	(926) Employee Pensions and Benefits	43,128,555	41,913,468
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	1,726,872	1,332,005
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	14,095,546	6,458,420
192	(930.2) Miscellaneous General Expenses	1,114,296	2,177,555
193	(931) Rents	2,996,811	3,236,075
194	TOTAL Operation (Enter Total of lines 181 thru 193)	151,418,034	156,072,117
195	Maintenance		
196	(935) Maintenance of General Plant	7,757,754	7,843,633
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	159,175,788	163,915,750
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	3,040,638,999	3,603,952,086

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	/ /	2012/Q4

FOOTNOTE DATA

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

Allocated maintenance expenses for joint use computer hardware, computer software and communication equipment are determined by using various factors, which include number of remote terminal units, number of radios, number of employees and other factors assigned to each function.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	RQ	AEG 3			
2	AEP Service Corporation	OS	23			
3	AEP Service Corporation	OS	20			
4	Ameren Energy Marketing	OS				
5	American Municipal Power-Ohio	OS				
6	Associated Elect Cooperative	OS				
7	B.P. Energy Company	OS				
8	Barclays Bank PLC	OS				
9	Beech Ridge Energy LLC	OS				
10	BP AMOCO	OS				
11	Buckeye Rural Electric Admin	OS				
12	Constellation Engy Commodities	OS				
13	DP&L Power Services	OS				
14	Duke Energy Carolinas, LLC	OS				
	Total					

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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	Dynegy Power Marketing Inc.	OS				
2	East KY Power Co-Op Power Mktg	OS				
3	EDF Trading North America LLC	OS				
4	Energy America, LLC	OS				
5	Entergy Power Serv	OS				
6	Exelon Generation - Power Team	OS				
7	Fowler Ridge II Wind Farm LLC	OS				
8	J ARON & Company	OS				
9	JP Morgan Ventures Energy Corp	OS				
10	LG&E Utilities Power Sales	OS				
11	Midwest ISO	OS				
12	Mingo Junction Energy Center	OS				
13	Mizuho Securities USA Inc.	OS				
14	National Power Cooperative Inc.	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	National Power Cooperative Inc.	OS				
2	NC Electric Membership Corp.	OS				
3	NextEra Energy Power Mktg LLC	OS				
4	No Carolina Muni Pwr Agency #1	OS				
5	NRG Power Marketing Inc.	OS				
6	Ohio DSM Interuptible Credit	OS				
7	Ohio Economic Development Rider	OS				
8	Ohio ESP Capacity Cost	OS				
9	Old Dominion Elec.	OS				
10	OVEC Power Scheduling	OS				
11	Paulding Wind Farm	OS				
12	PJM Environmental Info Sys Inc.	OS				
13	PJM Interconnection	OS				
14	R L Downs	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Southern Maryland Elec Coop Inc.	OS				
2	Southern Company	OS				
3	The Energy Authority	OS				
4	TVA Bulk Power Trading	OS				
5	UBS Securities LLC	OS				
6	Wabash Valley Power Assn Inc.	OS				
7	Wisconsin Electric Power Co.	OS				
8	Wisconsin Power & Light	OS				
9	WPPI Energy	OS				
10	Wyandot Solar LLC	OS				
11	ADJUSTMENT	OS				
12						
13						
14						
	Total					

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
6,634,276			62,395,756	141,186,702		203,582,458	1
5,283,737				174,240,043		174,240,043	2
2,796				75,510		75,510	3
			11,319			11,319	4
17,661				780,303		780,303	5
2,634				75,004		75,004	6
				-40,001		-40,001	7
				467,461		467,461	8
				-73,160		-73,160	9
				-63,964		-63,964	10
				1,045,248		1,045,248	11
115,625			2,109,442	3,415,956		5,525,398	12
				70,100		70,100	13
33				2,455		2,455	14
17,646,286			134,068,214	517,165,557	-9,082,913	642,150,858	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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)	
			19,613			19,613	1
349				9,079		9,079	2
			40,411			40,411	3
				166,645		166,645	4
1,884				44,982		44,982	5
				2,926,381		2,926,381	6
277,843				17,850,091		17,850,091	7
				-74,399		-74,399	8
			133,625			133,625	9
3,734				163,556		163,556	10
12,199			2	342,926		342,928	11
29,534				524,080		524,080	12
				630,422		630,422	13
			148,645	2,458,239		2,606,884	14
17,646,286			134,068,214	517,165,557	-9,082,913	642,150,858	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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)	
35,983							1
230				8,832		8,832	2
				342,087		342,087	3
6				179		179	4
299				10,781		10,781	5
				-7,454,799		-7,454,799	6
					4,689,818	4,689,818	7
					-13,772,731	-13,772,731	8
581				19,455		19,455	9
1,952,388			65,397,391	59,488,326		124,885,717	10
				7,540		7,540	11
				373		373	12
2,982,565			3,780,633	109,962,753		113,743,386	13
				138		138	14
17,646,286			134,068,214	517,165,557	-9,082,913	642,150,858	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2012/Q4

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)	
478				15,723		15,723	1
42				2,329		2,329	2
36,326				1,547,130		1,547,130	3
239,315				5,420,021		5,420,021	4
				2,049,210		2,049,210	5
			5			5	6
			4,207			4,207	7
			17,656			17,656	8
			9,509			9,509	9
15,768				1,354,812		1,354,812	10
				-1,832,992		-1,832,992	11
							12
							13
							14
17,646,286			134,068,214	517,165,557	-9,082,913	642,150,858	

Name of Respondent Ohio Power Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2012/Q4

FOOTNOTE DATA

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

AEP Affiliate.

Schedule Page: 326.2 Line No.: 7 Column: l

The PUCO authorized OPCO to defer any under recovery of purchased power expense equal to the difference between the ESP tariff rate and the rate paid by certain customers under the Economic Development Rider (EDR). Charges/Credits to the (EDR) regulatory asset are offset to account 5550110.

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

The PUCO authorized OPCO to defer the difference between Electric Security Plan (ESP) Capacity Cost incurred up to $188/MW-day and RPM pricing as approved by the PUCO in Case No. 10-2929-EL-UNC. A portion of the charges to the (ESP) regulatory asset are offset to account 5550117.

Schedule Page: 326.3 Line No.: 11 Column: a

Reclass between 447 and 555 accounts to incorporate certain trading/marketing activity. The amounts represented on Page 310-311 and 326-327 are equal and off-setting.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	PJM Network Integ Trans Rev	Various	Various	FNO
2	PJM Network Integ Trans Serv	Various	Various	FNO
3	PJM Trans Enhancement Rev	Various	Various	FNO
4	PJM Trans Enhancement Rev Whlsle	Various	Various	FNO
5	PJM Network Integ Rev - Affil	Various	Various	FNS
6	PJM Trans Enhancement Rev - Affil	Various	Various	FNS
7	PJM Point to Point Trans Service	Various	Various	LFP
8	PJM Trans Owner Admin Revenue	Various	Various	OLF
9	PJM Trans Owner Serv - Affiliated	Various	Various	OLF
10	PJM Trans Owner Serv Rev Whlsle	Various	Various	OLF
11	PJM Expansion Costs Recovery	Various	Various	OS
12	PJM Trans Distribution & Metering	Various	Various	OS
13	RTO Formation Cost Recovery	Various	Various	OS
14	SECA Transmission Rev	Various	Various	OS
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
PJM OATT	Various	Various				1
PJM OATT	Various	Various				2
PJM OATT	Various	Various				3
PJM OATT	Various	Various				4
PJM OATT	Various	Various				5
PJM OATT	Various	Various				6
PJM OATT	Various	Various				7
PJM OATT	Various	Various				8
PJM OATT	Various	Various				9
PJM OATT	Various	Various				10
PJM OATT	Various	Various				11
PJM OATT	Various	Various				12
PJM OATT	Various	Various				13
PJM OATT	Various	Various				14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	0	0	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.
12,606,431			12,606,431	1
51,420,648			51,420,648	2
817,927			817,927	3
83,734			83,734	4
25,252,050			25,252,050	5
156,459			156,459	6
3,521,291			3,521,291	7
	1,546,235		1,546,235	8
	886,094		886,094	9
	238,919		238,919	10
687,476			687,476	11
		1,355,970	1,355,970	12
364,687			364,687	13
		1,255,682	1,255,682	14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
94,910,703	2,671,248	2,611,652	100,193,603	

Name of Respondent Ohio Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2012/Q4

FOOTNOTE DATA

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

Effective October 1, 2004, the administration of the transmission tariff was turned over to PJM. PJM does not provide any detail except for the total revenue by the major classes listed.

Schedule Page: 328 Line No.: 12 Column: m

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

Schedule Page: 328 Line No.: 14 Column: m

See "Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund" in footnote #2 Rate Matters Notes to Financial Statements.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

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

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
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23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Wheeling Power	LFP					1,351,836	1,351,836
2	PJM-Ehancements	OS					15,371,655	15,371,655
3	PJM-NITS	OS					5,943,866	5,943,866
4	Other	OS					427	427
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						22,667,784	22,667,784

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2012/Q4

FOOTNOTE DATA

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

Affiliated Company.

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

Amount represents charges for leased lines.

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

Transmission Enhancement Charges and Credits (PJM OATT Schedule 12).

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	502,158
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	16,094
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	46,116
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Affiliated Billings (net)	-294,301
7	Associated Business Development	1,091,815
8	Utility Corp Borrowing Program Shared Costs	66,905
9	Corporate Contributions & Memberships	822,724
10	Gridsmart Initiative	-1,117,233
11	Chamber of Commerce	23,991
12	Clearing of Unclaimed Funds (business to business)	-48,350
13	Various Items <$5,000	4,377
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
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32		
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35		
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37		
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41		
42		
43		
44		
45		
46	TOTAL	1,114,296

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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			23,926,774		23,926,774
2	Steam Production Plant	304,974,095	12,053,443			317,027,538
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	3,038,210	2,174			3,040,384
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	9,223,915				9,223,915
7	Transmission Plant	44,851,117				44,851,117
8	Distribution Plant	94,896,667				94,896,667
9	Regional Transmission and Market Operation					
10	General Plant	2,600,803		274,113		2,874,916
11	Common Plant-Electric					
12	TOTAL	459,584,807	12,055,617	24,200,887		495,841,311

B. Basis for Amortization Charges

Line 1, Column D $23,925,113 represents amortization of capitalized software development costs over a 5 year life and $1,661 represents amortization of franchise over the life of the franchise.

Line 10, Column D represents amortization of leasehold improvements to equipment and structures over the life of the lease.

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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 GENERATION						
13	311 - Amos	43,518			2.29		
14	311 - Cardinal	43,712			2.38		
15	311 - Conesville	55,594			1.79		
16	311 - Conesville Scrubb	3,766			1.79		
17	311 - Gavin	109,966			2.44		
18	311 - Gavin JMG	1,200			2.44		
19	311 - Gypsum Unloader	22			2.38		
20	311 - Kammer	35,237					
21	311 - Mitchell	82,600			2.87		
22	311 - Muskingum U1-4	28,878					
23	311 - Muskingum U5	23,635			2.80		
24	311.1 - MR U5 Coal Hndl	6,245					
25	311 - Picway	6,668					
26	311 - Putnam	853			2.29		
27	311 - Sporn	10,981					
28	311.15 - Beckjord	1,351					
29	311.15 - Conesville U4	17,653			1.58		
30	311.15 - Stuart	25,698			1.75		
31	311.15 - Zimmer	169,711			1.41		
32	312 - Amos	834,055			2.88		
33	312 - Cardinal	590,412			3.16		
34	312 - Cardinal SCR	5,556			10.00		
35	312 - Conesville	378,703			1.90		
36	312 - Conesville Scrubb	93,040			1.90		
37	312 - Gavin	802,076			2.96		
38	312 - Gavin JMG	713,766			2.96		
39	312 - Gavin SCR	26,740			10.00		
40	312 - Gypsum Unloader	13,203			3.12		
41	312 - Kammer	229,101					
42	312 - Mitchell	1,492,352			3.90		
43	312 - Mitchell SCR	13,254			10.00		
44	312 - Muskingum U1-4	197,251					
45	312 - Muskingum U5	221,687			3.43		
46	312 - Muskingum U5 SCR	4,112			10.00		
47	312.1 - MR U5 Coal Hndl	47,234					
48	312 - Picway	24,151					
49	312 - Putnam	1,544			2.88		
50	312 - Simulator	125			2.88		

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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	312 - Sporn	101,442					
13	312.15 - Beckjord	11,735					
14	312.15 - Conesville U4	253,948			1.66		
15	312.15 - Stuart	439,827			2.41		
16	312.15 - Zimmer	399,803			1.57		
17	314 - Amos	69,567			2.78		
18	314 - Cardinal	50,594			2.99		
19	314 - Conesville	102,247			2.02		
20	314 - Gavin	190,291			2.91		
21	314 - Kammer	47,847					
22	314 - Mitchell	105,849			2.86		
23	314 - Muskingum U1-4	57,953					
24	314 - Muskingum U5	47,723			3.19		
25	314 - Picway	6,277					
26	314 - Sporn	28,843					
27	314.15 - Beckjord	3,710					
28	314.15 - Conesville U4	30,612			1.84		
29	314.15 - Stuart	57,488			2.29		
30	314.15 - Zimmer	122,736			1.52		
31	315 - Amos	16,273			2.32		
32	315 - Cardinal	21,677			2.66		
33	315 - Conesville	35,714			1.57		
34	315 - Conesville Scrubb	2,273			1.57		
35	315 - Gavin	59,510			2.28		
36	315 - Kammer	18,239					
37	315 - Mitchell	30,048			2.39		
38	315 - Muskingum U1-4	19,097					
39	315 - Muskingum U5	9,472			2.62		
40	315 - Picway	4,009					
41	315 - Putnam	146			2.32		
42	315 - Simulator	870			2.32		
43	315 - Sporn	7,982					
44	315.15 - Beckjord	762					
45	315.15 - Conesville U4	4,503			1.71		
46	315.15 - Stuart	10,670			1.90		
47	315.15 - Zimmer	92,191			1.44		
48	316 - Amos	7,767			2.62		
49	316 - Cardinal	6,715			2.98		
50	316 - Conesville	15,690			1.85		

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	316 - Conesville Scrubb	55			1.85		
13	316 - Gavin	21,682			2.73		
14	316 - Kammer	6,535					
15	316 - Mitchell	14,240			2.79		
16	316 - Muskingum U1-4	9,723					
17	316 - Muskingum U5	3,907			2.94		
18	316.1- MR U5 Coal Hndl	390					
19	316 - Picway	2,811					
20	316 - Putnam	150			2.62		
21	316 - Simulator	2,348			2.62		
22	316 - Sporn	3,485					
23	316.15 - Beckjord	1,212					
24	316.15 - Conesville U4	1,091			1.80		
25	316.15 - Stuart	5,385			2.39		
26	316.15 - Zimmer	16,489			1.51		
27	TOTAL STEAM	8,937,253					
28							
29	HYDRO GENERATION						
30	331	49,979			2.78		
31	332	6,304			2.60		
32	333	43,865			2.56		
33	334	10,018			2.57		
34	335	4,434			2.36		
35	TOTAL HYDRO	114,600					
36							
37	OTHER GENERATION						
38	341 - Darby	3,334			1.48		
39	341 - Waterford	14,242			2.86		
40	342 - Darby	4,579			1.50		
41	342 - Waterford	3,011			2.86		
42	344 - Darby	161,591			1.63		
43	344 - Waterford	164,592			2.86		
44	345 - Darby	17,351			1.51		
45	345 - Waterford	29,198			2.86		
46	346 - Darby	3,085			1.45		
47	346 - Waterford	5,632			2.86		
48	TOTAL OTHER	406,615					
49							
50	TRANSMISSION						

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	352	84,920	55.00	5.00	2.02	R3	
13	352.15	358	55.00	5.00	2.02	R3	
14	352 - Kammer	15					
15	352 - Muskingum U1-4	22					
16	352 - Picway	7					
17	352 - Sporn U2 and U4	62					
18	353	1,036,326	43.00	-30.00	2.29	R1	
19	353.15	23,713	43.00	-30.00	2.29	R1	
20	353 - Kammer	1,294					
21	353 - Muskingum U1-4	3,801					
22	353 - Picway	330					
23	353 - Sporn U2 and U4	704					
24	354	3,469	60.00		1.88	R4	
25	354.15	18,005	60.00		1.88	R4	
26	354 - All Other	151,550	60.00		1.88	R4	
27	355	136,083	39.00	-4.00	3.52	R1	
28	355.15	3,876	39.00	-4.00	3.52	R1	
29	355 - All Other	96,553	39.00	-4.00	3.52	R1	
30	356	76,353	44.00	-4.00	1.91	R4	
31	356.15	14,046	44.00	-4.00	1.91	R4	
32	356 - All Other	203,033	44.00	-4.00	1.91	R4	
33	357	396	50.00	-1.00	2.26	R2	
34	357 - All Other	10,498	50.00	-1.00	2.26	R2	
35	358	1,058	50.00	-16.00	3.27	R2	
36	358 - All Other	18,628	50.00	-16.00	3.27	R2	
37	TOTAL TRANSMISSION	1,885,100					
38							
39	DISTRIBUTION						
40	361	20,466	60.00	19.00	2.03	R1.5	
41	362	530,737	40.00	16.00	2.90	L0	
42	363	5,062	15.00		6.67	SQ	
43	364	597,024	32.00	87.00	5.34	L0	
44	365	599,271	30.00	16.00	3.30	L0	
45	366	176,022	50.00		1.79	R2	
46	367	515,500	36.00	14.00	3.39	R0.5	
47	368	659,834	34.00	15.00	3.34	R1.5	
48	369	290,501	33.00	20.00	3.54	R0.5	
49	370	158,036	36.00	17.00	3.43	S1	
50	370.16	16,800			14.29		

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	371	50,202	12.00	21.00	9.63	L0	
13	372	104	30.00		3.33	R1	
14	373	35,591	20.00	18.00	5.40	L0	
15	TOTAL DISTRIBUTION	3,655,150					
16							
17	GENERAL PLANT						
18	390	116,264	45.00	5.00	2.14	L1	
19	390 - Kammer	35					
20	390 - Sporn U2 and U4	4					
21	391	7,726	30.00		3.33	SQ	
22	391.15	31	30.00		3.33	SQ	
23	391 - Kammer	132					
24	391 - Muskingum U1-4	6					
25	391 - Picway	71					
26	391 - Sporn U2 and U4	122					
27	392	44	50.00		2.00	SQ	
28	392 - Picway	27					
29	393	608	34.00		2.94	SQ	
30	393 - Picway	22					
31	393 - Sporn U2 and U4	1					
32	394	32,202	30.00	9.00	3.58	SQ	
33	394 - Muskingum U1-4	9					
34	394 - Picway	11					
35	395	1,008	28.00		3.57	SQ	
36	395 - Muskingum U1-4	87					
37	396	613	26.00	-6.00	3.61	SQ	
38	396 - Muskingum U1-4	10					
39	397	55,056	35.00		2.86	SQ	
40	397.14 - Zimmer	12	35.00		2.86	SQ	
41	397.15 - Stuart	8	35.00		2.86	SQ	
42	397.16	2,175	7.00		14.29		
43	397 - Kammer	11					
44	397 - Muskingum U1-4	41					
45	397 - Picway	18					
46	397 - Sporn U2 and U4	14					
47	398	3,921	25.00		4.00	SQ	
48	398 - Picway	115					
49	TOTAL GENERAL PLANT	220,404					
50							

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	DEPRECIABLE SUM	15,219,122					
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
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50							

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FOOTNOTE DATA

Schedule Page: 336 Line No.: 2 Column: b
Includes depreciation expense for capital leased assets in accordance with FASB No. 13

Schedule Page: 336 Line No.: 10 Column: b
Includes depreciation expense for capital leased assets in accordance with FASB No. 13

Schedule Page: 336 Line No.: 20 Column: b
The Kammer plant was classified as impaired as of November 30, 2012. The current plan is to operate the plant through its scheduled end of life (04/2015). AEP will continue to record a depreciable base for this plant on FERC Pg. 337; however, no additional depreciation will be recorded after Nov. 30, 2012, on this impaired asset.

Schedule Page: 336 Line No.: 22 Column: b
Muskingum Units 1-4 were classified as impaired as of November 30, 2012. The current plan is to operate these units through their scheduled end of life (04/2015). AEP will continue to record a depreciable base for these units on FERC Pg. 337; however, no additional depreciation will be recorded after Nov. 30, 2012, on this impaired asset.

Schedule Page: 336 Line No.: 25 Column: b
The Picway plant was classified as impaired as of November 30, 2012. The current plan is to operate this plant through its scheduled end of life (04/2015). AEP will continue to record a depreciable base for this plant on FERC Pg. 337; however, no additional depreciation will be recorded after Nov. 30, 2012, on this impaired asset.

Schedule Page: 336 Line No.: 27 Column: b
Sporn Units 2 and 4 were classified as impaired as of November 30, 2012. The current plan is to operate these units through their scheduled end of life (04/2015). AEP will continue to record a depreciable base for these units on FERC Pg. 337; however, no additional depreciation will be recorded after Nov. 30, 2012, on this impaired asset.

Schedule Page: 336 Line No.: 28 Column: b
Beckjord Unit 6 was classified as impaired as of November 30, 2012. The current plan is to operate this unit through its scheduled end of life (04/2015). AEP will continue to record a depreciable base for this unit on FERC Pg. 337; however, no additional depreciation will be recorded after Nov. 30, 2012, on this impaired asset.

Schedule Page: 336.5 Line No.: 12 Column: b
(1) Depreciable plant base in column B represents plant balances as of 11/30/2012

(2) Subaccounts .15 to all accounts indicate a segregation of facilities owned as tenants in common by Duke Energy, The Dayton Power and Light Company and the Respondent

(3) Depreciation for 2012 was computed monthly by application of rate to prior month ending balances

(4) In Case No. 91-418-EL-AIR for Columbus Southern Power and for Ohio Power Company, in Case No. 94-996-EL-AIR, AEP received approval to merge these two companies into one company, Ohio Power Company. For financial reporting, this merger was completed at December 31, 2011. Financial reporting for the year 2012 presented one surviving Ohio Power Company. Factors presented in Section C for the year 2012, are for the surviving Ohio Power Company.

(5) In December 2012, AEP retired Conesville Plant Unit 3 and Retrofit from its fleet

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	PUCO charge for funding the cost of hearing				
2	and review process for long-term forcasts.	273,842		273,842	
3					
4	Racine Hydro Project #2570				
5	Proportion of Cost of Administering the				
6	Federal Water Power Act	87,615		87,615	
7					
8	AEP Ohio Electric Security Plan				
9	PUCO Case No. 11-346-EL-SSO (OPCO)				
10	PUCO Case No. 11-348-EL-SSO (CSP)		991,905	991,905	
11					
12	Ohio East Pool Modification Filing				
13	PUCO Case No. 12-1126-EL-UNC				
14	FERC Case No. ER13-233-000 (APCo RS)				
15	FERC Case No. ER13-234-000 (KPCo RS)				
16	FERC Case No. ER13-235-000 (I&M RS)				
17	FERC Case No. ER13-236-000 (AEP Gen RS)				
18	FERC Case No. ER13-237-000 (OPCo RS)		67,004	67,004	
19					
20	AEP Ohio Distribution Case				
21	PUCO Case No. 11-351-EL-AIR (CSP)				
22	PUCO Case No. 11-352-EL-AIR (OPCO)		47,386	47,386	
23					
24	Ohio Securitization				
25	PUCO Case No. 12-1969-EL-ATS		66,646	66,646	
26					
27	Ohio Corporate Separation				
28	PUCO Case No. 12-1126-EL-UNC				
29	FERC Case No. EC13-26-000		134,718	134,718	
30					
31	Miscellaneous Items		57,756	57,756	
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	361,457	1,365,415	1,726,872	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Electric	928	273,842					2
							3
							4
							5
Electric	928	87,615					6
							7
							8
							9
Electric	928	991,905					10
							11
							12
							13
							14
							15
							16
							17
Electric	928	67,004					18
							19
							20
							21
Electric	928	47,386					22
							23
							24
Electric	928	66,646					25
							26
							27
							28
Electric	928	134,718					29
							30
Electric	928	57,756					31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		1,726,872					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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) Generation	
2	(b) Fossil-fuel Steam	6 items under $50,000
3		
4	(c) Internal combustion or gas turbine	1 items under $50,000
5		
6	(e) Unconventional Generation	3 items under $50,000
7		
8	A.(2) Transmission	4 items under $50,000
9		
10	(a) Overhead	1 items under $50,000
11		
12	A.(3) Distribution	1 items under $50,000
13		
14	A.(5) Environment	Industrial Advisory Committee - Southern Co.
15		3 items under $50,000
16		
17	A.(6) Other	7 items under $50,000
18		
19	A (7) TOTAL COST INCURRED INTERNALLY	
20		
21	ELECTRIC UTILITY RESEARCH, DEVELOPMENT &	
22	DEMONSTRATION PERFORMED EXTERNALLY	
23		
24	B. (1) Electric Power Research Institute	EPRI - Full Scale Demonstration of the Sorbent Activation Process (SAP)
25		EPRI Environmental Controls
26		EPRI Environmental Science
27		EPRI Research Portfolio
28		Ohio River Ecological Research Program
29		80 items under $50,000
30		
31	B. (4) Research Support to Others	5 items under $50,000
32		
33	B(5) TOTAL COSTS INCURRED EXTERNALLY	
34		
35		
36		
37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
82,613		506	82,613		2
					3
5,836		506	5,836		4
					5
22,356		506,588	22,356		6
					7
14,260		566	14,260		8
					9
56		566	56		10
					11
56		588	56		12
					13
631,847		506	631,847		14
6,881		506	6,881		15
					16
56,317		Various	56,317		17
					18
820,222			820,222		19
					20
					21
					22
					23
	119,768	506	119,768		24
	321,002	506	321,002		25
	1,188,856	506	1,188,856		26
	665,678	Various	665,678		27
	55,181	506	55,181		28
	561,614	Various	561,614		29
					30
	91,797	566,588	91,797		31
					32
	3,003,896		3,003,896		33
					34
					35
					36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	45,862,900		
4	Transmission	2,525,808		
5	Regional Market			
6	Distribution	20,832,403		
7	Customer Accounts	11,352,933		
8	Customer Service and Informational	3,482,087		
9	Sales	968,710		
10	Administrative and General	8,509,560		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	93,534,401		
12	Maintenance			
13	Production	46,952,644		
14	Transmission	4,682,527		
15	Regional Market			
16	Distribution	23,105,489		
17	Administrative and General	2,853,329		
18	TOTAL Maintenance (Total of lines 13 thru 17)	77,593,989		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	92,815,544		
21	Transmission (Enter Total of lines 4 and 14)	7,208,335		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	43,937,892		
24	Customer Accounts (Transcribe from line 7)	11,352,933		
25	Customer Service and Informational (Transcribe from line 8)	3,482,087		
26	Sales (Transcribe from line 9)	968,710		
27	Administrative and General (Enter Total of lines 10 and 17)	11,362,889		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	171,128,390	8,257,845	179,386,235
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
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	171,128,390	8,257,845	179,386,235
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	56,900,076	2,745,728	59,645,804
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	56,900,076	2,745,728	59,645,804
72	Plant Removal (By Utility Departments)			
73	Electric Plant	13,455,733	649,310	14,105,043
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	13,455,733	649,310	14,105,043
77	Other Accounts (Specify, provide details in footnote):			
78	151 - Fuel Stock	-1,163		-1,163
79	152 - Fuel Stock Undistributed	10,523,666		10,523,666
80	154 - Materials & Supplies	-297		-297
81	163 - Stores Expense Undistributed	7,398,660	-7,398,660	
82	182 - Other Regulatory Assets	2,968	-2,968	
83	183 - Preliminary Survey	-14,364	14,364	
84	184 - Clearing Accounts	4,265,619	-4,265,619	
85	185 - ODD Temporary Facilites	156,880		156,880
86	186 - Misc Deferred Debits	5,937,795		5,937,795
87	188 - Research & Development	8,110		8,110
88	402 - Maintenance Exp	298		298
89	426 - Political Activities	47,642		47,642
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	28,325,814	-11,652,883	16,672,931
96	TOTAL SALARIES AND WAGES	269,810,013		269,810,013

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

COMMON UTILITY PLANT AND EXPENSES

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				32,260,426
3	Net Sales (Account 447)				(96,648,898)
4	Transmission Rights				(5,461,296)
5	Ancillary Services				2,008,713
6	Other Items (list separately)				
7	Congestion				7,484,448
8	Operating Reserves				(3,598,539)
9	Transmission Purchase Expense				36,629
10	Transmission Losses				18,954,870
11	Meter Corrections				235,838
12	Inadvertent				54,278
13	Capacity Credits				(3,360,520)
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
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40					
41					
42					
43					
44					
45					
46	TOTAL				(48,034,051)

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

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

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

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

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

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

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

Name of Respondent Ohio Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2012/Q4

FOOTNOTE DATA

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	/ /	2012/Q4

FOOTNOTE DATA

Schedule Page: 400 Line No.: 1 Column: b

Ohio Power Company's transmission service is administered through an RTO/ISO and requested information is not available on an individual operating company basis.

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	30,897,005
3	Steam	44,185,868			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	2,596,133
5	Hydro-Conventional	138,403			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	30,029,692
7	Other	5,104,429			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	952
9	Net Generation (Enter Total of lines 3 through 8)	49,428,700	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	17,646,286	27	Total Energy Losses	3,551,204
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	67,074,986
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)	67,074,986			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

MONTHLY PEAKS AND OUTPUT

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

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	6,334,808	2,412,004	7,880	13	1100
30	February	5,403,275	1,971,743	7,575	13	0800
31	March	5,005,802	1,756,893	7,266	5	2100
32	April	5,022,665	2,083,335	6,577	12	0800
33	May	5,247,590	2,053,167	8,122	25	1600
34	June	5,153,803	1,950,457	9,670	29	1400
35	July	6,596,739	2,950,351	9,578	18	1300
36	August	6,579,405	3,446,540	9,136	3	1500
37	September	5,044,422	2,623,268	8,626	6	1600
38	October	5,591,146	3,298,416	6,854	29	1900
39	November	5,227,095	2,928,093	6,971	28	2000
40	December	5,868,236	3,499,859	7,097	21	1800
41	TOTAL	67,074,986	30,974,126			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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: *AMOS-OPCO SHARE* (b)			Plant Name: *AMOS-TOTAL* (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			1973			1971
4	Year Last Unit was Installed			1973			1973
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			867.00			2933.00
6	Net Peak Demand on Plant - MW (60 minutes)			870			2900
7	Plant Hours Connected to Load			6067			6751
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			867			2900
10	When Limited by Condenser Water			867			2900
11	Average Number of Employees			99			333
12	Net Generation, Exclusive of Plant Use - KWh			3675995000			12969046000
13	Cost of Plant: Land and Land Rights			652289			5960346
14	Structures and Improvements			43728909			142064144
15	Equipment Costs			930279121			3086063540
16	Asset Retirement Costs			20345008			34950087
17	Total Cost			995005327			3269038117
18	Cost per KW of Installed Capacity (line 17/5) Including			1147.6417			1114.5715
19	Production Expenses: Oper, Supv, & Engr			1638545			7328288
20	Fuel			105975625			387920098
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			6994320			30315650
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			60297			231213
26	Misc Steam (or Nuclear) Power Expenses			711752			5309216
27	Rents			339			-30913
28	Allowances			70224			-75584
29	Maintenance Supervision and Engineering			835955			3334482
30	Maintenance of Structures			914577			3744080
31	Maintenance of Boiler (or reactor) Plant			7990136			37099334
32	Maintenance of Electric Plant			1094659			7763539
33	Maintenance of Misc Steam (or Nuclear) Plant			1842076			6761255
34	Total Production Expenses			128128505			489700658
35	Expenses per Net KWh			0.0349			0.0378
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	1457609	27500	0	5241095	91162	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12278	137121	0	12248	137108	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	69.234	138.120	0.000	69.618	138.152	0.000
41	Average Cost of Fuel per Unit Burned	67.770	137.288	0.000	68.425	137.374	0.000
42	Average Cost of Fuel Burned per Million BTU	2.760	23.838	0.000	2.793	23.856	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.027	0.000	0.000	0.028	0.000	0.000
44	Average BTU per KWh Net Generation	9785.000	0.000	0.000	9939.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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: *CARDINAL-OPCO SHARE* (b)			Plant Name: *CARDINAL-TOTAL* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	STEAM			STEAM		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	PARTIAL OUTDOOR			PARTIAL OUTDOOR		
3	Year Originally Constructed	1967			1967		
4	Year Last Unit was Installed	1967			1977		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	615.00			1881.00		
6	Net Peak Demand on Plant - MW (60 minutes)	603			1829		
7	Plant Hours Connected to Load	5251			7335		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	595			1810		
10	When Limited by Condenser Water	585			1790		
11	Average Number of Employees	320			320		
12	Net Generation, Exclusive of Plant Use - KWh	2969568000			11901854000		
13	Cost of Plant: Land and Land Rights	417438			605833		
14	Structures and Improvements	43942040			102631627		
15	Equipment Costs	675193120			1868322229		
16	Asset Retirement Costs	12171475			12171475		
17	Total Cost	731724073			1983731164		
18	Cost per KW of Installed Capacity (line 17/5) Including	1189.7952			1054.6152		
19	Production Expenses: Oper, Supv, & Engr	878870			4160700		
20	Fuel	58653543			161785092		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	9988159			26509279		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	269200			825089		
26	Misc Steam (or Nuclear) Power Expenses	2637075			8940086		
27	Rents	0			0		
28	Allowances	318336			0		
29	Maintenance Supervision and Engineering	905792			2898236		
30	Maintenance of Structures	985695			3151992		
31	Maintenance of Boiler (or reactor) Plant	6414063			21566928		
32	Maintenance of Electric Plant	2959076			7869819		
33	Maintenance of Misc Steam (or Nuclear) Plant	864813			2578628		
34	Total Production Expenses	84874622			240285849		
35	Expenses per Net KWh	0.0286			0.0202		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	1111271	16647	0	2832888	79280	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12416	137069	0	12335	137357	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	47.026	135.483	0.000	53.379	133.024	0.000
41	Average Cost of Fuel per Unit Burned	46.308	134.064	0.000	52.956	144.098	0.000
42	Average Cost of Fuel Burned per Million BTU	1.865	23.288	0.000	2.147	24.978	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.017	0.000	0.000	0.013	0.000	0.000
44	Average BTU per KWh Net Generation	9320.000	0.000	0.000	5914.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

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

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
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
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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: *CONESVILLE 5 & 6* (b)			Plant Name: *PICWAY* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	STEAM			STEAM		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	FULL OUTDOOR			OUTDOOR BOILER		
3	Year Originally Constructed	1957			1926		
4	Year Last Unit was Installed	1978			1955		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	888.00			106.25		
6	Net Peak Demand on Plant - MW (60 minutes)	920			97		
7	Plant Hours Connected to Load	7818			100		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	800			100		
10	When Limited by Condenser Water	800			95		
11	Average Number of Employees	300			4		
12	Net Generation, Exclusive of Plant Use - KWh	3307999000			3957000		
13	Cost of Plant: Land and Land Rights	236497			125244		
14	Structures and Improvements	59488899			6667669		
15	Equipment Costs	628332380			37247859		
16	Asset Retirement Costs	36925172			5820663		
17	Total Cost	724982948			49861435		
18	Cost per KW of Installed Capacity (line 17/5) Including	816.4222			469.2841		
19	Production Expenses: Oper, Supv, & Engr	2090576			338061		
20	Fuel	111552731			273542		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	14010796			96044		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1115248			230527		
26	Misc Steam (or Nuclear) Power Expenses	11577768			302432		
27	Rents	0			0		
28	Allowances	1411888			2599		
29	Maintenance Supervision and Engineering	323901			50890		
30	Maintenance of Structures	592477			43195		
31	Maintenance of Boiler (or reactor) Plant	11991729			254524		
32	Maintenance of Electric Plant	2942587			30025		
33	Maintenance of Misc Steam (or Nuclear) Plant	862610			35859		
34	Total Production Expenses	158472311			1657698		
35	Expenses per Net KWh	0.0479			0.4189		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	1601727	6832	0	2840	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11574	136599	0	11076	135800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	57.762	130.727	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	57.809	58.120	0.000	76.915	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.497	10.130	0.000	3.472	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.028	0.000	0.000	0.055	0.000	0.000
44	Average BTU per KWh Net Generation	11220.000	0.000	0.000	16137.000	0.000	0.000

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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: *CONESVILLE 4- TOTAL* (b)			Plant Name: *CONES 4 OPCO SHARE* (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			1973			1973
4	Year Last Unit was Installed			-			-
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			841.50			366.05
6	Net Peak Demand on Plant - MW (60 minutes)			785			375
7	Plant Hours Connected to Load			3723			3723
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			780			339
10	When Limited by Condenser Water			780			339
11	Average Number of Employees			0			0
12	Net Generation, Exclusive of Plant Use - KWh			2481045000			999774000
13	Cost of Plant: Land and Land Rights			74828			32550
14	Structures and Improvements			40595999			17659259
15	Equipment Costs			668481819			290789591
16	Asset Retirement Costs			4278339			1861078
17	Total Cost			713430985			310342478
18	Cost per KW of Installed Capacity (line 17/5) Including			847.8087			847.8144
19	Production Expenses: Oper, Supv, & Engr			0			839178
20	Fuel			0			50016652
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			0			2353340
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			74271
26	Misc Steam (or Nuclear) Power Expenses			0			5075692
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			0			91216
30	Maintenance of Structures			0			212951
31	Maintenance of Boiler (or reactor) Plant			0			5965977
32	Maintenance of Electric Plant			0			988523
33	Maintenance of Misc Steam (or Nuclear) Plant			0			415069
34	Total Production Expenses			0			66032869
35	Expenses per Net KWh			0.0000			0.0660
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	1124299	1192	0	458210	519	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11605	135976	0	12030	135976	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	79.697	0.000	0.000	78.958	0.000	0.000
41	Average Cost of Fuel per Unit Burned	83.732	119.597	0.000	83.291	119.562	0.000
42	Average Cost of Fuel Burned per Million BTU	3.608	20.941	0.000	3.462	20.935	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.038	0.000	0.000	0.038	0.000	0.000
44	Average BTU per KWh Net Generation	10525.000	0.000	0.000	11036.000	0.000	0.000

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Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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: *SPORN-OPCO SHARE* (d)			Plant Name: *SPORN-TOTAL* (e)			Plant Name: *GAVIN* (f)			Line No.
		STEAM			STEAM			STEAM	1
		CONVENTIONAL			CONVENTIONAL			CONVENTIONAL	2
		1950			1950			1974	3
		1960			1960			1975	4
		305.00			610.00			2600.00	5
		288			579			2656	6
		6593			6593			7566	7
		0			0			0	8
		300			600			2640	9
		290			580			2640	10
		54			109			272	11
		585060000			988614000			17220105000	12
		101828			172464			2934019	13
		10980931			23886886			111174486	14
		141751812			267070534			1814739760	15
		15240772			25809548			23536298	16
		168075343			316939432			1952384563	17
		551.0667			519.5728			750.9171	18
		737986			1637944			4033791	19
		21767868			37794170			402439464	20
		0			0			0	21
		820318			1639158			62923290	22
		0			0			0	23
		0			0			0	24
		499264			998491			120370	25
		1935838			3295116			14914116	26
		26456			48146			0	27
		559966			592984			3211376	28
		129767			322643			1339515	29
		634775			1187321			2085358	30
		1718522			3847465			30568387	31
		618757			1441118			4017037	32
		645863			1140019			1306739	33
		30095380			53944575			526959443	34
		0.0514			0.0546			0.0306	35
Coal	Oil		Coal	Oil		Coal	Oil		36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
272670	3943	0	468195	8020	0	7196957	36511	0	38
11891	137293	0	11842	137089	0	11914	136839	0	39
73.077	132.876	0.000	73.651	133.638	0.000	55.110	133.643	0.000	40
71.479	128.797	0.000	71.924	129.062	0.000	53.380	127.832	0.000	41
3.006	22.336	0.000	3.037	22.415	0.000	2.240	22.242	0.000	42
0.033	0.000	0.000	0.034	0.000	0.000	0.022	0.000	0.000	43
11123.000	0.000	0.000	11315.000	0.000	0.000	9971.000	0.000	0.000	44

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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: *MUSKINGUM* (d)			Plant Name: *MITCHELL* (e)			Plant Name: *KAMMER* (f)			Line No.
		STEAM			STEAM			STEAM	1
		CONVENTIONAL			OUTDOOR BOILER			CONVENTIONAL	2
		1953			1971			1958	3
		1968			1971			1959	4
		1530.00			1633.00			713.00	5
		958			1561			570	6
		4487			6898			6284	7
		0			0			0	8
		1380			1560			630	9
		1305			1560			585	10
		134			231			60	11
		1789615000			7544338000			1784836000	12
		668886			1122477			165993	13
		58753345			82827772			35122710	14
		615471496			1669125486			299044158	15
		31499602			2735918			4922286	16
		706393329			1755811653			339255147	17
		461.6950			1075.2062			475.8137	18
		2038862			3020926			1012563	19
		60887786			217183199			68551808	20
		0			0			0	21
		3169159			13072219			-439569	22
		0			0			0	23
		0			0			0	24
		164731			816			7709	25
		4318682			9220440			1161900	26
		0			0			0	27
		5887078			409820			2541935	28
		230756			7108886			3860096	29
		745257			1276367			374484	30
		6122457			18948501			5925197	31
		1318534			4571970			862448	32
		790904			1048831			689538	33
		85674206			275861975			84548109	34
		0.0479			0.0366			0.0474	35
Coal	Oil		Coal	Oil		Coal	Oil		36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
788796	21143	0	2986398	47110	0	913501	10161	0	38
12294	137075	0	12417	135816	0	11296	136519	0	39
84.143	124.442	0.000	70.254	140.800	0.000	69.514	141.365	0.000	40
71.854	125.408	0.000	68.529	135.109	0.000	69.305	140.717	0.000	41
2.922	21.783	0.000	2.759	23.686	0.000	3.068	24.542	0.000	42
0.032	0.000	0.000	0.027	0.000	0.000	0.035	0.000	0.000	43
10888.000	0.000	0.000	9866.000	0.000	0.000	11591.000	0.000	0.000	44

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

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

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

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

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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: *BECKJORD-OPCO SHARE* (d)			Plant Name: *STUART-OPCO SHARE* (e)			Plant Name: (f)			Line No.
STEAM			STEAM						1
CONVENTIONAL			SEMI-OUTDOOR						2
1969			1970						3
-			1974						4
57.60			634.61			0.00			5
51			589			0			6
5858			6983			0			7
0			0			0			8
49			600			0			9
48			600			0			10
0			0			0			11
226966000			2935173000			0			12
175499			1477657			0			13
1350619			25700424			0			14
17419320			513869627			0			15
225419			1050643			0			16
19170857			542098351			0			17
332.8274			854.2228			0			18
95538			1292107			0			19
6196985			90349865			0			20
0			0			0			21
-48711			4684053			0			22
0			0			0			23
0			0			0			24
34			419244			0			25
66246			3882719			0			26
0			-13189			0			27
0			0			0			28
80851			511820			0			29
88528			979399			0			30
348318			11609520			0			31
93721			4668072			0			32
198811			144217			0			33
7120321			118527827			0			34
0.0314			0.0404			0.0000			35
Coal	Oil		Coal	Oil					36
Tons	Barrels		Tons	Barrels					37
99869	892	0	1244559	20474	0	0	0	0	38
12186	137303	0	11595	137400	0	0	0	0	39
56.225	136.528	0.000	59.601	135.749	0.000	0.000	0.000	0.000	40
57.556	112.177	0.000	59.981	135.131	0.000	0.000	0.000	0.000	41
2.362	19.452	0.000	2.586	23.416	0.000	0.000	0.000	0.000	42
0.025	0.000	0.000	0.025	0.000	0.000	0.000	0.000	0.000	43
10747.000	0.000	0.000	9873.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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: *ZIMMER - OPCO SHARE* (d)			Plant Name: *WATERFORD* (e)			Plant Name: *DARBY* (f)			Line No.
		STEAM			COMBINED CYCLE			GAS TURBINE	1
		CONVENTIONAL			OUTDOOR HRSG			NO BOILER	2
		1991			2003			2001	3
		-			2003			2002	4
		362.11			917.00			650.00	5
		349			864			522	6
		4407			7722			205	7
		0			0			0	8
		333			840			507	9
		330			810			450	10
		0			29			0	11
		1142482000			5027420000			77009000	12
		5959406			3000000			713584	13
		169719335			14754445			3333937	14
		632434386			202645686			186606092	15
		396956			0			0	16
		808510083			220400131			190653613	17
		2232.7748			240.3491			293.3133	18
		644530			1660291			945479	19
		36539578			103753956			3446708	20
		0			0			0	21
		3804038			-933290			-670988	22
		0			0			0	23
		0			0			0	24
		1445			-4			7	25
		1747447			6506087			563602	26
		0			0			34963	27
		0			0			0	28
		996080			332728			175814	29
		1830282			501			15877	30
		5866993			5304465			-28074	31
		1722436			453289			668098	32
		4310931			307			124069	33
		57463760			117078330			5275555	34
		0.0503			0.0233			0.0685	35
Coal	Oil		Gas			Gas			36
Tons	Barrels		MCFs			MCFs			37
496611	21848	0	35748901	0	0	911229	0	0	38
11586	137712	0	1012000	0	0	1023000	0	0	39
57.452	130.187	0.000	2.894	0.000	0.000	3.677	0.000	0.000	40
57.339	129.164	0.000	2.893	0.000	0.000	3.677	0.000	0.000	41
2.474	22.332	0.000	2.859	0.000	0.000	3.594	0.000	0.000	42
0.025	0.000	0.000	0.021	0.000	0.000	0.044	0.000	0.000	43
10183.000	0.000	0.000	7196.000	0.000	0.000	12105.000	0.000	0.000	44

Name of Respondent Ohio Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2012/Q4

FOOTNOTE DATA

Schedule Page: 402 Line No.: -1 Column: b

Plant Name: Amos - This plant is owned jointly by Respondent and Appalachian Power Company, also a subsidiary of American Electric Power, Inc.

Schedule Page: 402 Line No.: -1 Column: d

Plant Name: Sporn - This plant is owned jointly by Respondent and Appalachian Power Company, also a subsidiary of American Electric Power, Inc.

Schedule Page: 402 Line No.: 20 Column: b

Expenses totaling $8,543,895 for deferred fuel and the Phase-in Recovery Rider are not included in the fuel totals that are broken down by generating plant.

Schedule Page: 402.1 Line No.: -1 Column: b

Plant Name: Cardinal - This plant is jointly owned by Respondent and Buckeye Power Company, a non-affiliate.

Schedule Page: 402.1 Line No.: -1 Column: e

Included in Mitchell Plant's investment are costs of $21,651(structures and improvements) and $13,203,231 (equipment). These amounts were paid by Ohio Power Company in gypsum unloading equipment located at Mountaineer Plant, which is owned and operated by Appalachian Power Company, a subsidiary of American Electric Power, Inc.

Schedule Page: 402.3 Line No.: -1 Column: b

Conesville Unit # 3 - Ohio Power Company retired December, 31, 2012. Lines 14 thru 17 do not include Conesville Unit # 3 cost data. Lines 19 thru 34 include Conesville Unit # 3 expense data prior to retirement.

Schedule Page: 402.3 Line No.: -1 Column: d

Beckjord Unit #6: This unit is commonly owned by Duke Energy, The Dayton Power and Light Company and the Respondent with undivided interests of 37.5%, 50.0% and 12.5%, respectively. Fuel expenses are shared on an energy received basis. All other expenses are shared on an ownership basis.

Schedule Page: 402.3 Line No.: -1 Column: e

Stuart: These units are commonly owned by Duke Energy, The Dayton Power and Light Company and the Respondent with undivided interests of 39%, 35% and 26%, respectively. Fuel expenses are shared on an energy received basis. All other expenses are shared on an ownership basis. (The diesel unit has been included with the steam unit as a Black Start Unit)

Schedule Page: 402.4 Line No.: -1 Column: b

Conesville Unit #4: This unit is commonly owned by Duke Energy,The Dayton Power and Light Company and the Respondent with undivided interests of 40.0%,16.5% and 43.5%, respectively. Fuel expenses are shared on an energy received basis. All other expenses are shared on an ownership basis.

Schedule Page: 402.4 Line No.: -1 Column: c

Conesville Unit #4 - Ohio Power Company Share: See footnote above.

Schedule Page: 402.4 Line No.: -1 Column: d

Zimmer: This unit is commonly owned by Duke Energy, The Dayton Power and Light Company and the Respondent with undivided interests of 46.5%, 28.1% and 25.4%, respectively. Fuel expenses are shared on an energy received basis. All other expenses are shared on an ownership basis.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2570 Plant Name: Racine (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	
2	Plant Construction type (Conventional or Outdoor)	Conventional Bulb	
3	Year Originally Constructed	1982	
4	Year Last Unit was Installed	1983	
5	Total installed cap (Gen name plate Rating in MW)	47.50	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	27	0
7	Plant Hours Connect to Load	8,273	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	48	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	4	0
12	Net Generation, Exclusive of Plant Use - Kwh	138,403,000	0
13	Cost of Plant		
14	Land and Land Rights	3,992	0
15	Structures and Improvements	49,979,341	0
16	Reservoirs, Dams, and Waterways	6,304,465	0
17	Equipment Costs	58,317,331	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	50,034	0
20	TOTAL cost (Total of 14 thru 19)	114,655,163	0
21	Cost per KW of Installed Capacity (line 20 / 5)	2,413.7929	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	69,431	0
24	Water for Power	29,229	0
25	Hydraulic Expenses	1,347	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	192,234	0
28	Rents	41,666	0
29	Maintenance Supervision and Engineering	952	0
30	Maintenance of Structures	123,198	0
31	Maintenance of Reservoirs, Dams, and Waterways	28,520	0
32	Maintenance of Electric Plant	326,918	0
33	Maintenance of Misc Hydraulic Plant	59,652	0
34	Total Production Expenses (total 23 thru 33)	873,147	0
35	Expenses per net KWh	0.0063	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
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			11
			12
			13
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			22
			23
			24
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			35
			36
			37
			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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						
2						
3						
4						
5						
6						
7						
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14						
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46						

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2012/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

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

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
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						19
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						41
						42
						43
						44
						45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Ohio Power Company							
2	0168 BAKER	DON MARQUIS	765.00	765.00	AT	26.41		1
3	0168 BAKER	DON MARQUIS	765.00	765.00	ST	10.32		1
4	0171 KAMMER	DUMONT	765.00	765.00	AT	100.19		1
5	0171 KAMMER	DUMONT	765.00	765.00	ST	126.14		1
6	0194 AMOS	NORTH PROCTORVILLE	765.00	765.00	ST	5.30		1
7	0195 GAVIN	MARYSVILLE	765.00	765.00	ST	124.40		1
8	0232 AMOS	GAVIN	765.00	765.00	ST	0.49		1
9	0233 GAVIN	KAMMER	765.00	765.00	ST	2.62		1
10	0263 KAMMER	SOUTH CANTON	765.00	765.00	AT	0.24		1
11	0263 KAMMER	SOUTH CANTON	765.00	765.00	ST	78.44		1
12	0269 NORTH PROCTORV	HANGING ROCK	765.00	765.00	ST	25.99		1
13	0270 HANGING ROCK	JEFFERSON	765.00	765.00	ST	6.14		1
14	0047 SPORN	MUSKINGUM	345.00	345.00	ST	46.52		1
15	0048 MUSKINGUM	CENTRAL	345.00	345.00	ST	28.10		1
16	0048 MUSKINGUM	CENTRAL	345.00	345.00	ST	53.94		2
17	0052 CENTRAL	EAST LIMA	345.00	345.00	ST	2.68		1
18	0052 CENTRAL	EAST LIMA	345.00	345.00	ST	71.36		2
19	0070 EAST LIMA	SORENSON	345.00	345.00	ST	42.58		1
20	0079 MUSKINGUM	TIDD	345.00	345.00	ST	83.57		2
21	0088 KAMMER EXT. NO. 1		345.00	345.00	ST	0.20		1
22	0088 KAMMER EXT. NO. 1		345.00	345.00	ST	0.38		1
23	0104 TIDD	CANTON CENTRAL	345.00	345.00	AT	37.29		1
24	0104 TIDD	CANTON CENTRAL	345.00	345.00	ST	14.21		1
25	0106 CANTON CENTRAL	JUNIPER	345.00	345.00	AT	4.06		1
26	0106 CANTON CENTRAL	JUNIPER	345.00	345.00	ST	1.36		1
27	0106 CANTON CENTRAL	JUNIPER	345.00	345.00	ST	0.55		2
28	0119 MUSKINGUM	OHIO CENTRAL	345.00	345.00	AT	30.75		1
29	0119 MUSKINGUM	OHIO CENTRAL	345.00	345.00	ST	12.51		1
30	0142 KAMMER EXT. NO. 2		345.00	345.00	ST	0.15		1
31	0142 KAMMER EXT. NO. 2		345.00	345.00	ST	0.30		1
32	0161 OHIO CENTRAL	FOSTORIA CENTRAL	345.00	345.00	AT	100.53		1
33	0161 OHIO CENTRAL	FOSTORIA CENTRAL	345.00	345.00	ST	5.99		1
34	0162 FOSTORIA CENTRAL	EAST LIMA	345.00	345.00	AT	34.47		1
35	0162 FOSTORIA CENTRAL	EAST LIMA	345.00	345.00	ST	5.35		1
36					TOTAL	7,610.95	160.65	617

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2012/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	0163 FOSTORIA CENTRAL	PEMBERVILLE	345.00	345.00	ST	19.29		2
2	0166 SOUTH CANTON	SAMMIS	345.00	345.00	ST	0.74		1
3	0167 SOUTH CANTON	STAR	345.00	345.00	ST	0.69		1
4	0172 SOUTHWEST LIMA		345.00	345.00	ST	14.68		2
5	0173 SOUTHWEST LIMA	MIAMI	345.00	345.00	AT	18.04		1
6	0173 SOUTHWEST LIMA	MIAMI	345.00	345.00	ST	0.97		1
7	0208 TIDD	COLIER	345.00	345.00	ST	0.31		2
8	0248 MARYSVILLE EXT NO		345.00	345.00	ST	4.22		2
9	0249 MARYSVILLE EXT NO		345.00	345.00	ST	4.84		2
10	0279 SOUTH CANTON	CANTON CENTRAL	345.00	345.00	ST	8.16		2
11	0365 WATERFORD	MUSKINGUM-SPORN	345.00	345.00	ST	0.98		
12	0366 BEVERLY EXTENSION		345.00	345.00	ST	0.10		
13	0001 LIMA	FT WAYNE	138.00	138.00	WP	0.10		2
14	0001 LIMA	FT WAYNE	138.00	138.00	ST	43.58		2
15	0004 HOWARD	ASHLAND	138.00	138.00	ST	6.15		1
16	0004 HOWARD	ASHLAND	138.00	138.00	ST	1.84		2
17	0005 WINDSOR	CANTON	138.00	138.00	ST	54.39		1
18	0005 WINDSOR	CANTON	138.00	138.00	WP	0.08		1
19	0006 WINDSOR	CANTON (WV)	138.00	138.00	ST	0.32		1
20	0007 PHILO	HOWARD	138.00	138.00	WP	0.05		2
21	0007 PHILO	HOWARD	138.00	138.00	ST	80.73		2
22	0010 FOSTORIA	PEMBERVILLE	138.00	138.00	ST	18.49		2
23	0010 FOSTORIA	PEMBERVILLE	138.00	138.00	ST	0.06		1
24	0010 FOSTORIA	PEMBERVILLE	138.00	138.00	WP			1
25	0011 PHILO	RUTLAND	138.00	138.00	ST	65.70		2
26	0016 SOUTH POINT	TURNER	138.00	138.00	ST	0.48		2
27	0018 PHILO	TORREY	138.00	138.00	ST	70.73		1
28	0019 CROOKSVILLE	WEST LANCASTER	138.00	138.00	ST	30.70		2
29	0020 PHILO	CANTON	138.00	138.00	ST	74.04		1
30	0025 TIDD	WAGENHALS	138.00	138.00	ST	53.45		1
31	0028 PORTSMOUTH	TRENTON NO. 2	138.00	138.00	WP	67.70		1
32	0028 PORTSMOUTH	TRENTON NO. 2	138.00	138.00	ST	0.24		1
33	0028 PORTSMOUTH	TRENTON NO. 2	138.00	138.00	ST	0.45		2
34	0032 TRENTON	MUNCIE	138.00	138.00	ST	24.62		1
35	0033 RUTLAND	SPORN	138.00	138.00	ST	4.81		2
36					TOTAL	7,610.95	160.65	617

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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	0034 SPORN	SOUTH POINT	138.00	138.00	ST	9.22		1
2	0034 SPORN	SOUTH POINT	138.00	138.00	ST	40.41		2
3	0036 SPORN	PORTSMOUTH	138.00	138.00	ST	0.05		1
4	0036 SPORN	PORTSMOUTH	138.00	138.00	ST	48.76		2
5	0037 HILLSBORO	MAYSVILLE	138.00	138.00	ST	33.65		1
6	0038 CROOKSVILLE	NORTH NEWARK	138.00	138.00	WP	30.67		1
7	0038 CROOKSVILLE	NORTH NEWARK	138.00	138.00	ST	0.58		2
8	0039 WEST LANCASTER	SOUTH BALTIMORE	138.00	138.00	WP	9.82		1
9	0041 NORTH NEWARK	WEST MT. VERNON	138.00	138.00	WP	20.28		1
10	0041 NORTH NEWARK	WEST MT. VERNON	138.00	138.00	ST	1.48		2
11	0042 SOUTH BALTIMORE	NORTH NEWARK	138.00	138.00	WP	21.04		1
12	0042 SOUTH BALTIMORE	NORTH NEWARK	138.00	138.00	ST	0.05		1
13	0042 SOUTH BALTIMORE	NORTH NEWARK	138.00	138.00	ST	0.08		2
14	0043 BELLEFONTE EXT.		138.00	138.00	ST	2.80		2
15	0044 SUMMERFIELD	NATRIUM	138.00	138.00	ST	27.07		2
16	0045 PHILO	MUSKINGUM	138.00	138.00	ST	23.16		2
17	0046 MUSKINGUM	SUMMERFIELD	138.00	138.00	ST	25.31		2
18	0049 FOSTORIA	EAST LIMA	138.00	138.00	WP	0.06		1
19	0049 FOSTORIA	EAST LIMA	138.00	138.00	ST	40.77		2
20	0050 EAST LIMA	LIMA	138.00	138.00	ST	4.43		2
21	0055 TORREY	WOOSTER	138.00	138.00	WP	26.39		1
22	0055 TORREY	WOOSTER	138.00	138.00	ST	2.30		1
23	0056 WEST MT. VERNON	SOUTH KENTON	138.00	138.00	WP	59.06		1
24	0057 SOUTH KENTON	STERLING	138.00	138.00	ST	0.09		1
25	0057 SOUTH KENTON	STERLING	138.00	138.00	WP	28.31		1
26	0058 SOUTH POINT	PORTSMOUTH	138.00	138.00	ST	0.04		1
27	0058 SOUTH POINT	PORTSMOUTH	138.00	138.00	ST	34.57		2
28	0059 PHILO	CROOKSVILLE	138.00	138.00	ST	15.37		2
29	0060 LIMA	STERLING	138.00	138.00	WP	1.89		1
30	0060 LIMA	STERLING	138.00	138.00	ST	4.07		1
31	0061 EAST LIMA	WEST LIMA	138.00	138.00	WP	0.15		2
32	0061 EAST LIMA	WEST LIMA	138.00	138.00	ST	11.19		2
33	0061 EAST LIMA	WEST LIMA	138.00	138.00	ST	1.05		3
34	0063 TORREY	MASSILLON	138.00	138.00	ST	0.29		2
35								
36					TOTAL	7,610.95	160.65	617

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1	0066 WAGENHALS	WEST CANTON	138.00	138.00	ST	9.16		1
2	0066 WAGENHALS	WEST CANTON	138.00	138.00	ST	0.85		2
3	0067 TORREY	AKRON	138.00	138.00	ST	0.28		1
4	0069 TIDD	SOUTH CADIZ	138.00	138.00	WP	16.59		1
5	0071 AKRON	CANTON	138.00	138.00	ST	3.75		1
6	0072 TIDD	WEIRTON NO. 2	138.00	138.00	WP	6.21		1
7	0072 TIDD	WEIRTON NO. 2	138.00	138.00	ST	0.05		1
8	0073 WEIRTON	SOUTH TORONTO	69.00	138.00	ST	0.48		2
9	0073 WEIRTON	SOUTH TORONTO	138.00	138.00	ST	0.14		1
10	0075 SPORN	KAISER NO. 1	138.00	138.00	ST	4.25		2
11	0076 LUCASVILLE	SARGENTS	138.00	138.00	WP	11.88		1
12	0078 TIDD	WINDSOR JCT.	138.00	138.00	ST	3.77		1
13	0080 NEWCOMERSTOWN	SOUTH COSHOCTON	138.00	138.00	WP	14.33		1
14	0081 FORD MOTOR EXT		138.00	138.00	ST	0.25		2
15	0086 SPORN	KAISER NO. 2	138.00	138.00	ST	5.67		2
16	0087 WINDSOR JUNCTION	TILTONVILLE	138.00	138.00	ST	3.81		1
17	0087 WINDSOR JUNCTION	TILTONVILLE	138.00	138.00	ST	0.30		2
18	0089 WEST PHILO EXT. NO.		138.00	138.00	WP	0.05		1
19	0090 WEST PHILO EXT. NO.		138.00	138.00	WP	0.13		1
20	0091 KAMMER	OHIO FERRO ALLOYS	138.00	138.00	WP	2.45		1
21	0091 KAMMER	OHIO FERRO ALLOYS (WV)	138.00	138.00	ST	0.71		1
22	0095 PORTSMOUTH	TRENTON NO. 1	138.00	138.00	WP	68.24		1
23	0095 PORTSMOUTH	TRENTON NO. 1	138.00	138.00	ST	1.04		1
24	0095 PORTSMOUTH	TRENTON NO. 1	138.00	138.00	ST	0.24		2
25	0096 THIVENER	BUCKEYE CO-OP	138.00	138.00	WP	6.16		1
26	0097 MERCERVILLE	APPLE GROVE	138.00	138.00	ST	5.11		2
27	0098 MILLWOOD EXT.		138.00	138.00	WP	0.10		1
28	0101 THIVENER EXT.		138.00	138.00	WP	0.09		1
29	0102 MEIGS EXT. NO. 1		138.00	138.00	WP	0.10		1
30	0103 MEIGS EXT NO. 2		138.00	138.00	WP	0.10		1
31	0103 MEIGS EXT NO. 2		138.00	138.00	ST	0.07		1
32	0108 OHIO CENTRAL	NORTH NEWARK	138.00	138.00	ST	0.33		2
33	0108 OHIO CENTRAL	NORTH NEWARK	138.00	138.00	WP	21.30		1
34	0110 NORTH STRASBURG		138.00	138.00	WP	0.06		1
35	0111 NORTH STRASBURG		138.00	138.00	WP	0.06		1
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1	0112 ZANESVILLE EXT.		138.00	138.00	ST	6.48		2
2	0113 HOWARD	BUCYRUS CENTER	138.00	138.00	ST	16.30		1
3	0113 HOWARD	BUCYRUS CENTER	138.00	138.00	ST	0.27		2
4	0114 SOUTH PEMBERVILLE	FREEMONT	138.00	138.00	WP	14.18		1
5	0114 SOUTH PEMBERVILLE	FREEMONT	138.00	138.00	ST	1.29		2
6	0115 SUMMERFIELD	BERNE	138.00	138.00	WP	3.46		1
7	0118 SOUTH COSHOCTON	WOOSTER	138.00	138.00	WP	39.51		1
8	0120 OHIO CENTRAL	COSHOCTON JCT.	138.00	138.00	ST	0.20		1
9	0120 OHIO CENTRAL	COSHOCTON JCT.	138.00	138.00	ST	14.52		2
10	0122 KAMMER	ORMET NO. 1	138.00	138.00	ST	1.71		2
11	0123 FINDLAY CENTER EXT.		138.00	138.00	ST	6.66		1
12	0125 TIDD	WEIRTON NO. 1	138.00	138.00	ST	0.41		2
13	0126 ARROYO	EAST LIVERPOOL	138.00	138.00	ST	0.15		1
14	0128 TIDD	NATRIUM	138.00	138.00	ST	0.26		1
15	0129 HOWARD	FOSTORIA	138.00	138.00	ST	0.50		1
16	0129 HOWARD	FOSTORIA	138.00	138.00	ST	44.38		2
17	0130 EAST WHEELERSB	TEXAS EASTERN	138.00	138.00	WP	1.99		1
18	0131 KAMMER	ORMET NO. 2	138.00	138.00	ST	1.55		2
19	0133 SUNNYSIDE	WAGENHALS NO. 1	138.00	138.00	ST	1.44		1
20	0133 SUNNYSIDE	WAGENHALS NO. 1	138.00	138.00	WP	2.23		1
21	0134 TIDD	WHEELING STEEL	138.00	138.00	ST	5.12		2
22	0141 MILLBROOK	SILOAM	138.00	138.00	ST	1.60		2
23	0141 MILLBROOK	SILOAM	138.00	138.00	SP	0.05		1
24	0143 ZANESVILLE	OHIO CENTRAL	138.00	138.00	WP	10.96		1
25	0143 ZANESVILLE	OHIO CENTRAL	138.00	138.00	ST	1.87		1
26	0144 TORREY	TIMKEN	138.00	138.00	WP	0.80		1
27	0144 TORREY	TIMKEN	138.00	138.00	ST	0.86		1
28	0145 CANTON CENTRAL	TIMKEN	138.00	138.00	SP	0.74		1
29	0145 CANTON CENTRAL	TIMKEN	138.00	138.00	ST	5.52		1
30	0146 EAST LIMA	WESTMINSTER	138.00	138.00	ST	8.38		2
31	0147 SUNNYSIDE	WAGENHALS NO. 2	138.00	138.00	WP	2.21		1
32	0149 CANTON CENTRAL	WAGENHALS	138.00	138.00	ST	2.02		2
33	0151 SOUTH CANTON	TORREY	138.00	138.00	ST	1.26		1
34	0151 SOUTH CANTON	TORREY	138.00	138.00	ST	1.60		2
35	0152 MALAGA	SPEIDEL	69.00	138.00	WP	11.99		1
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1	0153 BRIDGEVILLE EXT.		138.00	138.00	WP	1.88		1
2	0156 TIFFIN CENTER EXT.		138.00	138.00	WP	5.34		1
3	0156 TIFFIN CENTER EXT.		69.00	138.00	WP	1.81		2
4	0158 ROBINSON PARK	RICHLAND	138.00	138.00	WP	14.94		1
5	0159 EAST LIMA	RICHLAND	138.00	138.00	WP	27.74		1
6	0164 FOSTORIA CENTRAL	FOSTORIA	138.00	138.00	ST	0.08		1
7	0164 FOSTORIA CENTRAL	FOSTORIA	138.00	138.00	ST	1.48		2
8	0169 SOUTH CALDWELL	SOUTH CUMBERLAND	138.00	138.00	WP	10.86		1
9	0170 HANGING ROCK EXT.		138.00	138.00	ST	4.33		1
10	0174 CANTON CENTRAL	BLUEBELL	138.00	138.00	WP	0.36		1
11	0175 CANTON CENTRAL	CLOVERDALE	138.00	138.00	WP	0.38		1
12	0176 TIDD	STEUBENVILLE	138.00	138.00	ST	7.30		1
13	0177 SOUTHWEST LIMA	STERLING	138.00	138.00	ST	5.14		2
14	0177 SOUTHWEST LIMA	STERLING	34.00	138.00	WP	0.18		2
15	0177 SOUTHWEST LIMA	STERLING	138.00	138.00	SP	0.02		1
16	0177 SOUTHWEST LIMA	STERLING	138.00	138.00	WP	0.03		1
17	0178 SOUTHWEST LIMA	WEST LIMA	138.00	138.00	ST	0.88		2
18	0180 OHIO CENTRAL EXT		138.00	138.00	WP	0.46		1
19	0181 OHIO CENTRAL EXT		138.00	138.00	WP	0.45		1
20	0182 SOUTH CANTON	WEST CANTON	138.00	138.00	SP	5.20		2
21	0182 SOUTH CANTON	WEST CANTON	138.00	138.00	ST	2.59		1
22	0182 SOUTH CANTON	WEST CANTON	138.00	138.00	ST	2.26		2
23	0183 KAMMER	WEST BELLAIRE	138.00	138.00	ST	12.85		1
24	0183 KAMMER	WEST BELLAIRE	69.00	138.00	ST	0.33		2
25	0186 EAST ZANESVILLE		138.00	138.00	WP	0.04		1
26	0187 WEST BELLAIRE	BRUES	138.00	138.00	ST	4.26		1
27	0188 WEST BELLAIRE	TILTONVILLE	138.00	138.00	WP	11.49		1
28	0188 WEST BELLAIRE	TILTONVILLE	138.00	138.00	ST	0.50		1
29	0189 CROOKSVILLE TIE		138.00	138.00	WP	0.20		1
30	0190 SOUTHWEST LIMA	WEST MOULTON	138.00	138.00	WP	13.33		1
31	0193 TIFFIN CENTER	FREMONT CENTER	138.00	138.00	WP	11.84		1
32	0193 TIFFIN CENTER	FREMONT CENTER	138.00	138.00	ST	0.70		1
33	0193 TIFFIN CENTER	FREMONT CENTER	138.00	138.00	ST	0.04		2
34	0196 FREMONT CENTER	FREMONT	138.00	138.00	WP	3.02		1
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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	0198 N. PROCTORVILLE	EAST HUNTINGTON	138.00	138.00	ST	3.86		1
2	0198 N. PROCTORVILLE	EAST HUNTINGTON	34.00	138.00	ST	0.08		2
3	0200 CAMPBELL ROAD	MIDWEST CO-OP	138.00	138.00	WP	0.15		1
4	0201 N. PROCTORVILLE	SOUTH POINT	138.00	138.00	ST	0.04		1
5	0201 N. PROCTORVILLE	SOUTH POINT	138.00	138.00	ST	10.83		2
6	0202 MUSKINGUM	WOLF CREEK	138.00	138.00	WP	3.65		1
7	0202 MUSKINGUM	WOLF CREEK	138.00	138.00	ST	1.06		1
8	0203 SWITZER EXT. NO. 1		138.00	138.00	WP	0.04		1
9	0204 SWITZER EXT. NO. 2		138.00	138.00	WP	0.06		1
10	0210 BUCKLEY ROAD EXT.		138.00	138.00	SP	0.09		1
11	0210 BUCKLEY ROAD EXT.		138.00	138.00	WP	2.62		1
12	0213 WINDSOR EXT. NO. 2			138.00	WP	0.11		1
13	0221 DARRAH	NORTH PROCTORVILLE	138.00	138.00	ST	3.51		1
14	0223 DEXTER	MEIGS NO. 2	138.00	138.00	WP	5.53		1
15	0224 NORTH RUTLAND	MEIGS NO. 1	138.00	138.00	WP	3.84		1
16	0225 AMITY	ACADEMIA	138.00	138.00	ST	0.14		1
17	0225 AMITY	ACADEMIA	138.00	138.00	ST	6.33		2
18	0226 ACADEMIA	WEST MT. VERNON	138.00	138.00	ST	0.15		2
19	0226 ACADEMIA	WEST MT. VERNON	138.00	138.00	ST	5.95		1
20	0229 CANNELVILLE	GURNSEY MUSKINGUM C	138.00	138.00	WP	0.11		1
21	0230 FAIRCREST EXT.		138.00	138.00	SP	0.04		1
22	0235 WEST MILLERSPORT	HEATH	138.00	138.00	WP	8.95		1
23	0235 WEST MILLERSPORT	HEATH	138.00	138.00	ST	3.06		1
24	0238 NORTH	EXTENSION	138.00	138.00	ST	3.54		1
25	0240 NORTH CROWN CITY		138.00	138.00	WP	0.24		1
26	0241 NORTH CROWN CITY		138.00	138.00	WP	0.24		1
27	0242 HEATH EXT. NO. 2		138.00	138.00	ST	1.29		1
28	0243 HEATH EXT. NO. 1		138.00	138.00	ST	1.29		1
29	0244 EAST SIDE EXT.		138.00	138.00	WP	0.24		2
30	0244 EAST SIDE EXT.		138.00	138.00	ST	0.08		2
31	0245 SOUTHEAST CANTON	SUNNYSIDE	138.00	138.00	ST	2.31		2
32	0247 SOUTHEAST CANTON	WACO	138.00	138.00	ST	2.12		2
33	0252 WEST DOVER EXT.		138.00	138.00	WP	0.10		1
34	0253 WEST DOVER EXT.		138.00	138.00	WP	0.09		1
35	0254 BUCKEYE CO-OP EXT.		138.00	138.00	WP	0.21		1
36					TOTAL	7,610.95	160.65	617

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	0257 GREENLAWN EXT.		138.00	138.00	WP	1.09		2
2	0260 EAST PROCTORVILLE		138.00	138.00	ST	0.13		2
3	0264 FREMONT	SANDUSKY BAY	69.00	138.00	WP	12.13		1
4	0265 WEST DOVER	SUGARCREEK	138.00	138.00	WP	4.07		1
5	0267 NORTH PORTSMOUTH	CENTRAL PORTSMOUTH	138.00	138.00	WP	6.04		1
6	0273 BUCKLEY ROAD	FREMONT CENTER	69.00	138.00	WP	0.90		2
7	0274 WAYVIEW	HOOVER NORTH	69.00	138.00	ST	0.02		1
8	0274 WAYVIEW	HOOVER NORTH	69.00	138.00	ST	1.04		2
9	0275 WEST CANTON JCT.	WAYVIEW	138.00	138.00	WP	1.11		1
10	0275 WEST CANTON JCT.	WAYVIEW	138.00	138.00	SP	1.80		2
11	0275 WEST CANTON JCT.	WAYVIEW	138.00	138.00	ST	1.89		1
12	0276 BELDEN VILLAGE EXT.		138.00	138.00	SP	1.51		1
13	0280 EAST AMSTERDAM	CARROLL CO-OP	69.00	138.00	WP	7.98		1
14	0282 SOUTH POINT TIE		138.00	138.00	WP	0.09		1
15	0286 WEST CANTON TIE		138.00	138.00	SP	0.07		2
16	0289 OHIO CENTRAL EXT.		138.00	138.00	WP	0.27		1
17	0290 SOUTH CANTON EXT.		138.00	138.00	ST	0.71		2
18	0294 SOUTH CANTON EXT.		138.00	138.00	ST	0.31		2
19	0295 BROADACRE EXT.		138.00	138.00	SP	0.04		2
20	0307 WEST VAN WERT	DELPHOS CENTER	69.00	138.00	WP	1.70		1
21	0313 BUCKEYE COOP EXT.		138.00	138.00	WP	0.85		1
22	0316 ORDANANCE JCT.		138.00	138.00	SP	0.10		2
23	0317 GUERNSEY	MUSKINGUM CO-OP EXT.	138.00	138.00	WP	0.12		1
24	0318 BUCKEYE CO-OP EXT.		138.00	138.00	WP	0.15		1
25	0320 HEDDING ROAD	MORROW CO-OP	138.00	138.00	WP	0.09		1
26	0324 WEST MILLERSPORT	SOUTH CENTRAL POWER	138.00	138.00	WP	0.20		1
27	0325 SHELBY MUNICIPAL		138.00	138.00	ST	0.53		1
28	0326 BLOOMFIELD	GUERNSEY MUSKINGUM C	138.00	138.00	WP	0.41		1
29	0327 NORTH CENTRAL		138.00	138.00	WP	0.45		1
30	0328 NORTH CHESIRE	EXTENSION NO. 2	138.00	138.00				
31	0329 TYCOON EXT.		138.00	138.00	WP	0.29		1
32	0331 LICKING CO-OP EXT.		138.00	138.00	WP	0.04		1
33	0333 ASHLEY EXT		69.00	138.00	WP	0.62		1
34	0334 NORTH CHESIRE	EXTENTION NO. 1	138.00	138.00	ST	0.38		2
35	0336 SHUFFEL ROAD	TIMKEN RESEARCH	69.00	138.00	ST	0.66		1
36					TOTAL	7,610.95	160.65	617

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1	0337 TIMKEN, RICHVILLE EX		138.00	138.00	WP	1.11		2
2	0338 CONESVILLE COAL		138.00	138.00	WP	0.63		1
3	0339 A.G.A. GAS EXT.		138.00	138.00	WP	0.16		1
4	0342 EAST WOOSTER EXT.		138.00	138.00	ST	5.15		2
5	0343 EAST WOOSTER EXT.		138.00	138.00	WP	0.18		1
6	0343 EAST WOOSTER EXT.		138.00	138.00	WP	0.43		2
7	0344 WAGENHALS	LTV STEEL NO. 1	138.00	138.00	ST	0.65		1
8	0345 WAGENHALS	LTV STEEL NO. 2	138.00	138.00	ST	0.68		1
9	0346 FOSTORIA TIE		138.00	138.00	WP	0.02		1
10	0347 FOSTORIA CENTRAL		138.00	138.00	ST	0.10		2
11	0348 FOSTORIA CENTRAL		138.00	138.00	ST	0.10		1
12	0349 FOSTORIA POWER		138.00	138.00	ST	0.10		3
13	0350 HANCOCK WOOD		138.00	138.00	WP	0.03		1
14	0351 EAST LEIPSIC EXT		138.00	138.00	SP	6.57		2
15	0352 BUCKEYE CO-OP EXT		138.00	138.00	WP	0.09		1
16	0353 STERLING	FOUNDRY PARK	138.00	138.00	WP	0.91		1
17	0354 GAVIN EXT. NO. 1		138.00	138.00	ST	3.10		2
18	0355 GAVIN EXT. NO. 2		138.00	138.00	ST	3.01		2
19	0358 LICKING REC. EXT. A		138.00	138.00	WP	0.24		1
20	0359 BUCKHORN	HOLMES	138.00	138.00	WP	0.98		1
21	0360 ADAMS RUAL	EMERALD	138.00	138.00	WP	0.80		1
22	0361 RILEY CREEK	PAULDING PUTNAM	138.00	138.00	ST	1.20		1
23	0363 MEIGS NO. 2	WILKESVILLE	138.00	138.00		1.60		1
24	0364 NORTH CENTRAL		138.00	138.00		1.84		1
25	0368 BALL HOLLOW	WASHINGTON CO-OP	138.00	138.00		0.05		1
26	0371 SPENCER RIDGE	BUCKINGHAM COAL	138.00	138.00	WP	0.12		1
27	0370 BUCKEYE CO-OP EXT		138.00	138.00	ST	0.10		2
28	0372 NORTH BELLVILLE		138.00	138.00	WP	0.11		2
29	0375 HANTHORN RD	G.O. ETHANOL		138.00	ST	0.34		1
30	0376 WARNER EXTENSION	SUNNYSIDE-TORREY	138.00	138.00	WP	0.30		1
31	0377 YELLOWBUSH		138.00	138.00	ST	0.04		1
32	LINES < 132KV					2,449.21		
33								
34								
35								
36					TOTAL	7,610.95	160.65	617

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1	Columbus Southern Power Co							
2	FULLY OWNED TRANS							
3	BEATTY	HAYDEN	345.00	345.00	1			1
4	9032 BEATTY	HAYDEN	345.00	345.00	3	17.00		1
5	9034 CONESVILLE	CORRIDOR	345.00	345.00	3	54.00		1
6	C633 POINT N	STR. 96-1	345.00	345.00	1,3	4.24		1
7	HAYDEN	HYATT	345.00	345.00	1			1
8	HAYDEN	HYATT	345.00	345.00	2			1
9	9037 HAYDEN	HYATT	345.00	345.00	3	12.00		1
10	9038 HAYDEN	ROBERTS	345.00	345.00	1	11.53		1
11	9039 POINT Z HYATT	CORRIDOR	345.00	345.00	3	13.00		1
12	C613 KIRK EXT #1 (NORTH)		345.00	345.00	1	0.25		1
13	C614 KIRK EXT #2 (SOUTH)		345.00	345.00	1	0.25		1
14	8790 DAVIDSON	DUBLIN	138.00	138.00	4	3.16		1
15	C710 DUBLIN	SAWMILL	138.00	138.00	1	6.40		1
16	C795 KIMBERLY		138.00	138.00	1	0.56		2
17	C796 DON MARQUIS LOOP		138.00	138.00	1	6.60		1
18	C798 DON MARQUIS LOOP		138.00	138.00	1	0.65		1
19	C799 GREIF EXTENSION		138.00	138.00	4	0.66		2
20	C800 LICK	JACKSON	138.00	138.00	1	1.09		
21	C850 WILLOW ISLAND	MILL CREEK	138.00	138.00	1	9.14		1
22	C851 MILL CREEK	RIVERVIEW	138.00	138.00	1	10.80		1
23	C852 RIVERVIEW	CORNER	138.00	138.00	1	7.09		1
24	C853 CORNER	SHELL	138.00	138.00	1	2.13		1
25	C854 PARKERSBURG	CORNER	138.00	138.00	1	7.67		1
26	C855 MUSKINGUM	CORNER	138.00	138.00	1	15.79		1
27	C856 BELMONT	RIVERVIEW	138.00	138.00	1	0.86		1
28	C857 WASHINGTON	CORNER	138.00	138.00	1	6.51		1
29	C858 RIVERVIEW	ELKEM METALS	138.00	138.00	1	0.80		1
30	COMMONLY OWNED: (A)							
31	9001 BECKJORD	PIERCE	345.00	345.00	3			1
32	9002 PIERCE	FOSTER	345.00	345.00	3	24.00		1
33	9006 GREENE	BEATTY	345.00	345.00	3	49.00		1
34	9007 MARQUIS	POINT X	345.00	345.00	3	46.00		1
35	9009 STUART	GREENE	345.00	345.00	3	79.00		1
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1	9010 STUART	POINT M-KILLEN	345.00	345.00	3	13.00		1
2	STUART	FOSTER	345.00	345.00	3	55.00		1
3	9011 STUART	FOSTER	345.00	345.00	3	1.00		1
4	9041 STUART	ZIMMER	345.00	345.00	3	35.00		1
5	9044 ZIMMER	PORT UNION	345.00	345.00	3	10.00		1
6	9049 KILLEN-POINT O	MARQUIS	345.00	345.00				
7	POINT O-KILLEN	MARQUIS	345.00	345.00	3	32.00		1
8	POINT Y	BEATTY	345.00	345.00	3	15.00		1
9	9742 POINT Y	BEATTY	345.00	345.00	3		4.00	1
10	COMMONLY OWNED: (B)							
11	9031 BEATTY	BIXBY	345.00	345.00	3	13.00		1
12	STUART	TOWER 2	345.00	345.00	3			1
13	9042 TOWER 2	POINT Y	345.00	345.00	3	75.00		1
14	CONESVILLE	TOWER 71	345.00	345.00	2	51.00		1
15	9043 TOWER 71	BIXBY	345.00	345.00	3		15.00	1
16	POINT X	TOWER 27	345.00	345.00	3	17.00		1
17	9707 TOWER 27	BIXBY	345.00	345.00	3		9.00	1
18	COMMONLY OWNED: (C)							
19	9040 CONESVILLE	POINT Z	345.00	345.00	3	57.00		1
20	COMMONLY OWNED: (D)							
21	POINT Z	HYATT	345.00	345.00	3	9.00		1
22	POINT Z	HYATT	345.00	345.00	1	2.00		1
23	9740 POINT Z	HYATT	345.00	345.00	2			1
24	COMMONLY OWNED: (E)							
25	STUART	ZIMMER	345.00	345.00	3	1.00		1
26	9045 ZIMMER-SILVER	RED BANK	345.00	345.00	3	33.00	2.00	1
27	9145 ZIMMER-SILVER	RED BANK	345.00	345.00	3			1
28	9046 RED BANK	TERMINAL	345.00	345.00	3	7.00		1
29	9053 ZIMMER	PIERCE	345.00	345.00	3	1.00	36.00	1
30	ROBERTS	BETHEL	138.00	138.00	1			2
31	8001 ROBERTS	BETHEL	138.00	138.00	3	5.00		2
32	8002 ROBERTS	KENNY	138.00	138.00	4	3.00		1
33	C789 BEAVER 138KV		138.00	138.00				
34	BETHEL	LINWORTH	138.00	138.00	3		3.00	1
35	8004 BETHEL	LINWORTH	138.00	138.00	1	2.00		1
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5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	8005 PICWAY	HARRISON	138.00	138.00	3	1.00		1
2	8008 GROVES	BEXLEY	138.00	138.00	1	4.00		1
3	8009 BEXLEY	ST. CLAIR	138.00	138.00	1	4.00		1
4	BIXBY	LSII	138.00	138.00	1	1.00	2.00	1
5	BIXBY	LSII	138.00	138.00	2	2.00		1
6	8010 BIXBY	LSII	138.00	138.00	3			1
7	BIXBY	W. LANCASTER	138.00	138.00	2	18.00		1
8	BIXBY	W. LANCASTER	138.00	138.00	2			1
9	8011 BIXBY	W. LANCASTER	138.00	138.00	2	1.00		1
10	POSTON	ROSS	138.00	138.00	2	42.00		1
11	8012 POSTON	ROSS	138.00	138.00	3	1.00		1
12	8013 ROSS	DELANO	138.00	138.00	2	5.00		1
13	8013 ROSS	DELANO	138.00	138.00	1	0.32		1
14	CIRCLEVILLE	HARRISON	138.00	138.00	2	14.00		1
15	8014 CIRCLEVILLE	HARRISON	138.00	138.00	3	1.00		1
16	LSII	MARION	138.00	138.00	1	2.17		1
17	8015 LSII	MARION	138.00	138.00	3	3.00		1
18	8016 MARION	CANAL	138.00	138.00	4	4.00		1
19	8017 ST CLAIR	CLINTON	138.00	138.00	4	4.00		1
20	HARRISON	MARION	138.00	138.00	2	7.00		1
21	8018 HARRISON	MARION	138.00	138.00	3		3.00	1
22	8019 BIXBY	GROVES-ASTOR	138.00	138.00	1	13.00		1
23	8020 POSTON	HARRISON	138.00	138.00	2	53.98		1
24	8021 BEATTY	WILSON (EAST)	138.00	138.00	3	7.00	1.00	1
25	BEATTY	WILSON (WEST)	138.00	138.00	3		1.00	2
26	8022 BEATTY	WILSON (WEST)	138.00	138.00	3		9.00	1
27	8023 WAVERLY	SARGENTS	138.00	138.00	2	16.00		1
28	WAVERLY	ADAMS-SEAMAN	138.00	138.00	2	25.00		1
29	8024 WAVERLY	ADAMS-SEAMAN	138.00	138.00	2	11.00		1
30	CIRCLEVILLE	SCIPPO	138.00	138.00	2	2.00		1
31	8025 CIRCLEVILLE	SCIPPO	138.00	138.00	1	1.00		1
32	POSTON	LICK	138.00	138.00	1			1
33	8026 POSTON	LICK	138.00	138.00	3	35.00		1
34								
35								
36					TOTAL	7,610.95	160.65	617

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	WAVERLY	LICK	138.00	138.00	1			1
2	WAVERLY	LICK	138.00	138.00	2	16.00		1
3	8027 WAVERLY	LICK	138.00	138.00	3	11.00		1
4	MORSE	GENOA-KARL	138.00	138.00	3	4.00		1
5	8028 MORSE	GENOA-KARL	138.00	138.00	1	5.00		1
6	MORSE	GENOA-KARL	138.00	138.00	2	2.00		1
7	8029 OSU	HESS	138.00	138.00	4	1.00		1
8	8030 WILSON	FIFTH-HESS	138.00	138.00	3	3.00		1
9	WILSON	FIFTH-HESS	138.00	138.00	4	2.00		1
10	WILSON	ROBERTS	138.00	138.00	3	5.00		1
11	8031 WILSON	ROBERTS	138.00	138.00	1			1
12	WILSON	ROBERTS	138.00	138.00	1	1.00		2
13	BIXBY	BUCKEYE STEEL	138.00	138.00	3	3.00	1.00	1
14	BIXBY	BUCKEYE STEEL	138.00	138.00	2	2.00		1
15	8032 BIXBY	BUCKEYE STEEL	138.00	138.00	1	1.17		1
16	8033 GAY	VINE	138.00	138.00	4	2.00		1
17	EAST BROAD	GAHANNA	138.00	138.00	1	0.03	1.03	1
18	8034 EAST BROAD	GAHANNA	138.00	138.00	2	1.00		1
19	EAST BROAD	GAHANNA	138.00	138.00	2	3.00		1
20	8035 HYATT	SAWMILL	138.00	138.00	1			1
21	HYATT	SAWMILL	138.00	138.00	2	5.00		1
22	8036 GAHANNA	MORSE	138.00	138.00	2	5.00		1
23	GAHANNA	MORSE	138.00	138.00	2			1
24	CORRIDOR	MORSE-BLENDON	138.00	138.00	3		7.00	1
25	8037 CORRIDOR	MORSE-BLENDON	138.00	138.00	1	1.00		2
26	8038 CORRIDOR	MORSE	138.00	138.00	3	7.00		1
27	8039 KIRK	EAST BROAD	138.00	138.00	3	10.00		1
28	8040 KIRK	EAST BROAD	138.00	138.00	3		10.00	1
29	8041 CANAL	MOUND	138.00	138.00	4	2.00		1
30	8043 CONESVILLE	TRENT	138.00	138.00	3	52.00		1
31	CONESVILLE	TRENT	138.00	138.00	1			1
32	TRENT	DELAWARE	138.00	138.00	3	13.00		1
33	8044 TRENT	DELAWARE	138.00	138.00	1			1
34	8046 ST. CLAIR	MIFFLIN STELZER	138.00	138.00	1	7.00		1
35								
36					TOTAL	7,610.95	160.65	617

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1	KENNY	KARL	138.00	138.00	3	1.00		1
2	KENNY	KARL	138.00	138.00	3	3.00		1
3	8047 KENNY	KARL	138.00	138.00	4	3.00		1
4	MORSE	CLINTON	138.00	138.00	3		5.00	1
5	MORSE	CLINTON	138.00	138.00	3		3.00	1
6	8048 MORSE	HUNTLEY-CLINTON	138.00	138.00	3	3.00		1
7	BIXBY	GROVES	138.00	138.00	3	3.00		2
8	BIXBY	GROVES	138.00	138.00	1	1.00		2
9	BIXBY	GROVES	138.00	138.00	3			1
10	8049 BIXBY	GROVES	138.00	138.00	1			1
11	POSTON	STROUDS	138.00	138.00	1			1
12	8051 POSTON	STROUDS	138.00	138.00	2	7.00		1
13	8052 HYATT	DELAWARE	138.00	138.00	2	4.00		1
14	8053 BEATTY	CANAL	138.00	138.00	1	11.34	2.00	1
15	8055 CONESVILLE	OHIO CENTRAL	138.00	138.00	2	12.00		1
16	8056 EAST BROAD	ASTOR	138.00	138.00	1	3.00		1
17	8057 HARRISON	BEATTY	138.00	138.00	1,3	8.57	0.12	1
18	8058 HARRISON	S CENTRAL REA	138.00	138.00	1			1
19	8060 BEATTY	MCCOMB	138.00	138.00	1	2.00	3.00	1
20	MORSE	STELZER	138.00	138.00	4	2.00		1
21	8061 MORSE	STELZER	138.00	138.00	1	2.00		1
22	8062 HUNTLEY	LINWORTH	138.00	138.00	1	3.23	1.00	1
23	8065 HYATT	GENOA	138.00	138.00	1	5.00	9.00	1
24	BUCKEYE STEEL	GAY	138.00	138.00	1	3.00		1
25	8066 BUCKEYE STEEL	GAY	138.00	138.00	4	1.00		1
26	POSTON	ELLIOT-DEXTER	138.00	138.00	1			1
27	8067 POSTON	ELLIOT-DEXTER	138.00	138.00	2	7.00		1
28	8068 HYATT	HUNTLEY	138.00	138.00	1	12.00		1
29	LICK	ADDISON	138.00	138.00	2	29.00		1
30	8069 LICK	ADDISON	138.00	138.00	1			1
31	SCIPPO	SCIOTO TRAIL - DUPONT	138.00	138.00	1	1.00		1
32	SCIPPO	SCIOTO TRAIL - DUPONT	138.00	138.00	2		1.00	1
33	8070 SCIPPO	SCIOTO TRAIL-DUPONT	138.00	138.00	2	1.00		1
34								
35								
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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
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	DELANO	SCIOTO TRAIL	138.00	138.00	2	11.00		1
2	8071 DELANO	SCIOTO TRAIL	138.00	138.00	1	1.00		1
3	8071 DELANO	SCIOTO TRAIL	138.00	138.00	2	0.31		1
4	SAWMILL	BETHEL	138.00	138.00	1			1
5	8072 SAWMILL	BETHEL	138.00	138.00	3	5.00		1
6	8074 SCIPPO	HARGUS	138.00	138.00	1	1.00		1
7	8075 MOUND	ST. CLAIR	138.00	138.00	4	2.00		1
8	WAVERLY	MULBERRY ROSS	138.00	138.00	1	2.00		1
9	8077 WAVERLY	MULBERRY ROSS	138.00	138.00	1	2.06		1
10	8078 MCCOMB	SULLIVANT-GAY	138.00	138.00		8.00		2
11	MULBERRY	ROSS	138.00	138.00	1		2.00	1
12	MULBERRY	ROSS	138.00	138.00	2	3.00		1
13	8079 MULBERRY	ROSS	138.00	138.00	1	1.00		1
14	8080 EAST BROAD	BEXLEY	138.00	138.00	1	6.00		1
15	EAST BROAD	BEXLEY	138.00	138.00	2			1
16	8081 HYATT	ROSS	138.00	138.00	1	1.00		1
17	8082 CORRIDOR	GENOA	138.00	138.00	1			1
18	8083 CORRIDOR	GAHANNA	138.00	138.00	1	1.00		1
19	KIRK	W. MILLERSPORT	138.00	138.00	3		8.00	1
20	KIRK	W. MILLERSPORT	138.00	138.00	3			1
21	CONESVILLE	KIRK	138.00	138.00	2			1
22	CONESVILLE	KIRK	138.00	138.00	3	38.00		2
23	8086 CONESVILLE	KIRK	138.00	138.00	3	8.00		1
24	8088 HESS	VINE	138.00	138.00	4	2.00		1
25	8092 VINE	CITY OF COLUMBUS EAST	138.00	138.00	1	1.28		1
26	POSTON	W. LANCASTER	138.00	138.00	2	12.00		1
27	POSTON	W. LANCASTER	138.00	138.00	1			1
28	8096 POSTON	W. LANCASTER	138.00	138.00	2	23.00		1
29	8098 VINE	CITY OF COLUMBUS WEST	138.00	138.00	1	1.00		1
30	ST. CLAIR	VINE	138.00	138.00	1	1.00		1
31	8099 ST. CLAIR	VINE	138.00	138.00	4	1.00		1
32	8102 CLINTON	OSU	138.00	138.00	4	4.00		1
33	8105 DAVIDSON RD	ROBERTS-BETHEL	138.00	138.00	1			2
34	8129 OSU	HESS	138.00	138.00	4	1.00		1
35	8712 SCIPPO	EAST SCIPPO	138.00	138.00				
36					TOTAL	7,610.95	160.65	617

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	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	8788 FISHER 138KV		138.00	138.00	3	0.42		1
2	C792 CLAYBURNE	KENWORTH	138.00	138.00	1	0.32		1
3	C793 DELANO	KENWORTH	138.00	138.00	1	0.31		1
4	C794 BOLTON EXTENSION		138.00	138.00				
5	COMMONLY OWNED: (F)							
6	C633A BIXBY	POINT N	345.00	345.00	3	14.81		1
7	C633B KIRK	CORRIDOR	345.00	345.00	2	18.38		1
8	TRANSMISSION LINES	LESS THAN 132 KV				607.09	22.50	
9								
10	EXPENSES 765KV LINES							
11	EXPENSES 345KV LINES							
12	EXPENSES 138KV LINES							
13	EXPENSES <132KV LINES							
14								
15								
16								
17								
18								
19								
20								
21								
22								
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25								
26								
27								
28								
29								
30								
31								
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TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
954 ACSR	1,349,451	9,045,631	10,395,082					2
954 ACSR								3
954 ACSR	8,552,412	47,088,111	55,640,523					4
954 ACSR								5
1351.5 AC	112,858	1,885,346	1,998,204					6
1351.5 AC	6,337,173	30,096,661	36,433,834					7
1351.5 AC		314,184	314,184					8
1351.5 AC	471,961	1,245,089	1,717,050					9
1351.5 AC	6,908,385	48,233,192	55,141,577					10
1351.5 AC								11
1351.5 AC	1,120,972	10,994,722	12,115,694					12
1351.5 AC	555,058	4,046,333	4,601,391					13
1275 ACSR	73,162	7,507,317	7,580,479					14
2303 ACAR	835,696	7,885,454	8,721,150					15
2303 ACAR								16
1275 ACSR	570,628	9,414,121	9,984,749					17
2303 ACAR								18
1275 ACSR	398,655	2,572,059	2,970,714					19
1414 ACSR	569,553	9,681,540	10,251,093					20
1414 ACSR	324	15,980	16,304					21
1414 ACSR								22
954 ACSR	600,262	4,448,569	5,048,831					23
954 ACSR								24
954 ACSR	216,361	608,479	824,840					25
954 ACSR								26
954 ACSR								27
1414 ACSR	234,856	3,199,207	3,434,063					28
954 ACSR								29
1414 ACSR	374	30,950	31,324					30
1414 ACSR								31
954 ACSR	1,366,276	11,437,901	12,804,177					32
954 ACSR								33
954 ACSR	1,009,385	3,857,729	4,867,114					34
954 ACSR								35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954 ACSR	391,441	3,342,849	3,734,290					1
954 ACSR	12,388	475,023	487,411					2
954 ACSR	14,027	188,850	202,877					3
1414 ACSR	478,155	2,368,771	2,846,926					4
954 ACSR	415,420	1,876,114	2,291,534					5
954 ACSR								6
954 ACSR	940	225,938	226,878					7
1275 ACSR	102,208	1,124,942	1,227,150					8
2303 ACAR	168,828	1,016,681	1,185,509					9
954 ACSR	457,056	4,364,051	4,821,107					10
954 ACSR		13,499	13,499					11
								12
397.5 ACS	117,254	770,710	887,964					13
397.5 ACS								14
397.5 ACS	18,658	81,441	100,099					15
397.5 ACS								16
556.5 ACS	372,490	1,715,156	2,087,646					17
636 ACSR								18
556.5 ACS	6,248	7,833	14,081					19
556.5 ACS	280,472	1,814,082	2,094,554					20
556.5 ACS								21
336.4 ACS	54,900	408,770	463,670					22
477 ACSR								23
556.5 ACS								24
397.5 ACS	97,721	1,607,351	1,705,072					25
397.5 ACS	2,514	19,200	21,714					26
1033.5 AC								27
397.5 ACS	53,026	521,658	574,684					28
1033.5 AC		369,312	369,312					29
1033.5 AC	98,376	1,339,794	1,438,170					30
477 ACSR	129,031	2,009,240	2,138,271					31
477 ACSR								32
6X477 ACS								33
397.5 ACS		6,970	6,970					34
397.5 ACS	7,006	128,966	135,972					35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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397.5 ACS	84,508	1,272,740	1,357,248					1
397.5 ACS								2
477 ACSR	101,414	1,693,666	1,795,080					3
477 ACSR								4
477 ACSR	47,320	1,099,302	1,146,622					5
397.5 ACS	81,464	762,189	843,653					6
397.5 ACS								7
397.5 ACS	58,821	336,356	395,177					8
477 ACSR	59,245	600,879	660,124					9
477 ACSR								10
397.5 ACS	83,697	734,371	818,068					11
397.5 ACS								12
795 ACSR								13
397.5 ACS	20,086	226,058	246,144					14
556.5 ACS	72,502	940,770	1,013,272					15
636 ACSR	47,622	847,873	895,495					16
556.5 ACS	40,221	874,550	914,771					17
397.5 ACS	149,175	1,311,226	1,460,401					18
397.5 ACS								19
397.5 ACS								20
556.5 ACS	189,074	1,738,272	1,927,346					21
556.5 ACS								22
477 ACSR	315,468	2,916,074	3,231,542					23
336.4 ACS	108,533	1,624,231	1,732,764					24
477 ACSR								25
397.5 ACS	68,327	1,078,941	1,147,268					26
397.5 ACS								27
336.4 ACS	44,469	339,268	383,737					28
4/0 CU.	29,289	629,826	659,115					29
795 ACSR								30
556.5 ACS	279,319	869,029	1,148,348					31
556.5 ACS								32
556.5 ACS								33
1033.5 AC		32,552	32,552					34
								35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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556.5 ACS	310,450	478,693	789,143					1
795 ACSR								2
556.5 ACS		130,650	130,650					3
477 ACSR	27,518	480,847	508,365					4
200 CU	351,260	3,064,707	3,415,967					5
556.5 ACS	91,838	203,346	295,184					6
556.5 ACS								7
219.9 ACS	36,090	70,490	106,580					8
556.5 ACS								9
795 ACSR	14,809	219,973	234,782					10
636 ACSR	26,598	814,472	841,070					11
1780 ACSR	22,461	287,538	309,999					12
336.4 ACS	30,676	579,360	610,036					13
397.5 ACS	5,172	44,416	49,588					14
795 ACSR	30,216	315,247	345,463					15
556.5 ACS	23,575	252,728	276,303					16
556.5 ACS								17
397.5 ACS		6,879	6,879					18
397.5 ACS								19
556.5 ACS	11,019	105,822	116,841					20
556.5 ACS								21
477 ACSR	79,161	3,729,589	3,808,750					22
477 ACSR								23
477 ACSR								24
219.9 ACS	11,916	455,463	467,379					25
397.5 ACS	15,784	548,597	564,381					26
500 CU.		2,786	2,786					27
219.9 ACS		2,576	2,576					28
219.9 ACS	751	40,348	41,099					29
219.9 ACS	522	85,069	85,591					30
556.5 ACS								31
397.5 ACS	114,989	996,378	1,111,367					32
556.5 ACS								33
1033.5 AC		5,723	5,723					34
1033.5 AC		7,048	7,048					35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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336.4 ACS	16,999	106,597	123,596					1
556.5 ACS	210,656	423,220	633,876					2
556.5 ACS								3
556.5 ACS	139,504	477,239	616,743					4
556.5 ACS								5
4/0 ACSR	13,905	214,660	228,565					6
477 ACSR	206,654	1,424,062	1,630,716					7
556.5 ACS	98,865	848,748	947,613					8
636 ACSR								9
1033.5 AC	1,686	143,489	145,175					10
556.5 ACS	99,850	397,053	496,903					11
556.5 ACS	6,084	36,352	42,436					12
556.5 ACS	4,128	25,660	29,788					13
556.5 ACS	1,423	35,982	37,405					14
397.5 ACS	7,029	317,785	324,814					15
397.5 ACS								16
4/0 ACSR	14,193	131,571	145,764					17
1033.5 AC	1,475	136,392	137,867					18
1033.5 AC	120,715	201,698	322,413					19
397.5 ACS								20
556.5 ACS	115,909	300,858	416,767					21
556.5 ACS	40,871	154,440	195,311					22
954 ACSR								23
556.5 ACS	229,027	824,095	1,053,122					24
556.5 ACS								25
1033.5 AC	3,597	210,425	214,022					26
1033.5 AC								27
1033.5 AC	118,635	583,357	701,992					28
636 ACSR								29
636 ACSR	190,216	483,917	674,133					30
397.5 ACS		69,158	69,158					31
1033.5 AC	378	338,249	338,627					32
1780 ACSR	2,610	344,396	347,006					33
556.5 ACS								34
556.5 ACS	79,051	350,039	429,090					35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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336.4 ACS	7,806	88,199	96,005					1
556.5 ACS	84,321	242,878	327,199					2
556.5 ACS								3
636 ACSR	106,467	413,003	519,470					4
636 ACSR	339,163	1,218,004	1,557,167					5
1033.5 AC	16,563	389,064	405,627					6
1033.5 AC								7
556.5 ACS	35,642	357,967	393,609					8
636 ACSR	21,763	355,008	376,771					9
795 ACSR		25,021	25,021					10
795 ACSR		24,681	24,681					11
795 ACSR	57,799	498,842	556,641					12
1590 ACSR	155,698	1,224,034	1,379,732					13
4/0 CU.								14
556.5 ACS								15
556.5 ACS								16
556.5 ACS		55,737	55,737					17
556.5 ACS		19,301	19,301					18
556.6 ACS		19,770	19,770					19
795 ACSR	518,302	1,112,327	1,630,629					20
795 ACSR								21
795 ACSR								22
1033.5 AC	171,905	1,367,574	1,539,479					23
954 ACSR								24
556.5 ACS		4,938	4,938					25
556.5 ACS	147,936	439,211	587,147					26
795 ACSR	227,558	981,563	1,209,121					27
795 ACSR								28
556.5 ACS	868	10,088	10,956					29
636 ACSR	96,160	583,109	679,269					30
556.5 ACS	234,776	833,416	1,068,192					31
556.5 ACS								32
795 ACSR								33
795 ACSR	123,110	574,358	697,468					34
795 ACSR								35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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795 ACSR	171,730	742,532	914,262					1
795 ACSR								2
336.4 ACS	7,295	6,963	14,258					3
795 ACSR	263,763	1,589,142	1,852,905					4
795 ACSR								5
556.5 ACS	16,142	474,178	490,320					6
636 ACSR								7
556.5 ACS		5,580	5,580					8
556.5 ACS		6,304	6,304					9
795 ACSR	46,016	264,016	310,032					10
795 ACSR								11
	232	9,417	9,649					12
1033.5 AC	412	553,053	553,465					13
556.5 ACS	35,977	243,930	279,907					14
556.5 ACS	19,114	181,347	200,461					15
556.5 ACS	138,868	445,812	584,680					16
795 ACSR								17
556.5 ACS	23,751	555,222	578,973					18
795 ACSR								19
336.4 ACS		20,442	20,442					20
1033.5 AC		7,504	7,504					21
795 ACSR	327,915	3,936,041	4,263,956					22
795 ACSR								23
556.5 ACS	67,989	270,925	338,914					24
556.5 ACS	1	16,202	16,203					25
556.5 ACS	2	20,499	20,501					26
795 ACSR	108,502	105,267	213,769					27
556.5 ACS	35,321	45,208	80,529					28
795 ACSR	21,856	102,801	124,657					29
795 ACSR								30
1033.5 AC	207,578	631,713	839,291					31
1033.5 AC	189,408	524,861	714,269					32
1033.5 AC		12,561	12,561					33
1033.5 AC		6,432	6,432					34
556.5 ACS	1,299	23,155	24,454					35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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795 ACSR	28,216	98,324	126,540					1
1033.5 AC	2,527	47,088	49,615					2
795 ACSR	481,243	1,382,999	1,864,242					3
795 ACSR	299,605	283,917	583,522					4
795 ACSR	92,664	690,478	783,142					5
556.5 ACS	27,304	249,067	276,371					6
795 ACSR	24,583	397,019	421,602					7
795 ACSR								8
795 ACSR	86,454	1,173,162	1,259,616					9
795 ACSR								10
795 ACSR								11
795 ACSR	130,564	357,139	487,703					12
795 ACSR	212,391	1,004,078	1,216,469					13
795 ACSR		12,090	12,090					14
795 ACSR	123,243	279,035	402,278					15
636 ACSR		15,828	15,828					16
1033.5 AC	8,058	109,450	117,508					17
1033.5 AC	24,315	121,459	145,774					18
1780 ACSR		43,415	43,415					19
795 ACSR	30,533	162,383	192,916					20
556.5 ACS	9,488	103,743	113,231					21
1590 ACSR		13,046	13,046					22
556.5 ACS	974	41,700	42,674					23
556.5 ACS	18,223	32,856	51,079					24
795 ACSR	8	40,513	40,521					25
556.5 ACS		33,801	33,801					26
336.4 ACS								27
336.4 ACS	5,181	96,269	101,450					28
336.4 ACS	22,978	90,260	113,238					29
	4,300		4,300					30
556.5 ACS	8,496	92,336	100,832					31
336.4 ACS	940	22,202	23,142					32
336.4 ACS	68,548	130,886	199,434					33
1033.5 AC	11,603	84,918	96,521					34
795 ACSR	2,599	176,804	179,403					35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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TRANSMISSION LINE STATISTICS (Continued)

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1033.5 AC	137,311	591,797	729,108					1
1033.5 AC		163,120	163,120					2
336.4 ACS	1,249	218,178	219,427					3
556.5 ACS	53,089	209,764	262,853					4
795 ACSR	13,901	209,058	222,959					5
795 ACSR								6
1033.5 AC	67,168	102,244	169,412					7
1033.5 AC	1,218	118,525	119,743					8
336.4 ACS								9
1033.5 AC	3,617	45,851	49,468					10
1033.5 AC	10,877	59,075	69,952					11
336.4 ACS								12
556.5 ACS		12,614	12,614					13
795 ACSR	481,254	2,956,454	3,437,708					14
336.4 ACS	512	37,478	37,990					15
795 ACSR	6,744	75,116	81,860					16
1033.5 AC	144,421	1,714,306	1,858,727					17
1033.5 AC		2,032,646	2,032,646					18
556.5 ACS	1,275	62,153	63,428					19
336.4 ACS		375,238	375,238					20
556.5 ACS	135	230,743	230,878					21
336.4 ACS		372,700	372,700					22
	9,000	96,880	105,880					23
556.5 ACS	217,676	532,226	749,902					24
556.5 ACS		7,549	7,549					25
4/0 ACSR	-1	-41,451	-41,452					26
397.5 ACS		34,918	34,918					27
556.5 ACS		225,220	225,220					28
556.5 ACS		48,557	48,557					29
397.5 ACS								30
795 ACSR		65	65					31
	15,452,247	166,092,312	181,544,559					32
								33
								34
								35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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								1
								2
2-954 ACSR								3
2-954 ACSR	1,194,611	3,268,355	4,462,966					4
2-954 ACSR	480,308	5,228,162	5,708,470					5
2-954 ACSR	70,173	4,665,050	4,735,223					6
2-954 ACSR								7
2-954 ACSR								8
2-954 ACSR	835,964	1,916,457	2,752,421					9
2-954 ACSR	1,432,452	4,815,660	6,248,112					10
2-954 ACSR	679,010	4,014,617	4,693,627					11
636 ACSR 26/7		68,482	68,482					12
636 ACSR 26/7		67,644	67,644					13
2000 CU KCM		7,120,559	7,120,559					14
636 ACSR 26/7	254,401	1,251,386	1,505,787					15
636 ACSR 26/7	21,083	716,838	737,921					16
1033.5 KCM	1,297,075	10,611,994	11,909,069					17
1033.5 KCM		1,112,156	1,112,156					18
2000 kcm CU		9,807	9,807					19
								20
954 ACSR 45/7	49,381	970,051	1,019,432					21
954 ACSR 45/7	155,934	1,747,823	1,903,757					22
954 ACSR 45/7	69,245	1,415,282	1,484,527					23
336.4 ACSR 26/7	12,018	75,769	87,787					24
336.4&954 ACSR	62,117	381,813	443,930					25
556.5 ACSR 26/7	149,512	406,453	555,965					26
954 ACSR 45/7	29,932	225,730	255,662					27
954 ACSR 45/7	98,855	1,046,776	1,145,631					28
954 ACSR 45/7	2,143	1,024,374	1,026,517					29
								30
1414 ACSR	14,534	49,229	63,763					31
2-1024 ACAR	341,949	829,458	1,171,407					32
2-1024 ACAR	407,288	1,357,428	1,764,716					33
2-983 ACAR	224,274	1,376,209	1,600,483					34
2-1024 ACAR	457,134	2,262,033	2,719,167					35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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TRANSMISSION LINE STATISTICS (Continued)

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2-983 ACAR	110,255	1,559,205	1,669,460					1
2-1024 ACAR								2
2-1024 ACAR	380,541	1,547,728	1,928,269					3
2-954 ACSR	262,436	1,445,792	1,708,228					4
2-954 ACSR	292,501	1,255,302	1,547,803					5
		1,160,653	1,160,653					6
2-983 ACAR								7
2-983 ACAR								8
2-983 ACAR	106,814	569,305	676,119					9
								10
2-954 ACSR	238,833	747,276	986,109					11
2-954 ACSR								12
2-954 ACSR	679,660	2,141,019	2,820,679					13
2-954 ACSR								14
2-954 ACSR	360,944	2,120,084	2,481,028					15
2-954 ACSR								16
2-954 ACSR	213,385	563,492	776,877					17
								18
2-954 ACSR	1,514,424	5,947,769	7,462,193					19
								20
2-954 ACSR								21
2-954 ACSR								22
2-954 ACSR	613,989	2,097,710	2,711,699					23
								24
2-954 ACSR								25
2-954 ACSR	46,141	3,333,699	3,379,840					26
2-954 ACSR	261,902	3,054,661	3,316,563					27
2-954 ACSR	232,956	2,023,424	2,256,380					28
2-954 ACSR	153,013	531,322	684,335					29
636 ACSR								30
636 ACSR	115,938	877,798	993,736					31
2500 ALUM	15,618	2,565,158	2,580,776					32
0	1,623		1,623					33
636 ACSR								34
636 AA	24,771	294,624	319,395					35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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636 ACSR		5,881	5,881					1
636 ACSR	259,495	446,742	706,237					2
636 AA	81,899	623,525	705,424					3
636 ACSR								4
636 ACSR								5
636 ACSR	50,964	3,079,914	3,130,878					6
4/O CWC								7
954 ACSR								8
636 ACSR	65,673	1,352,070	1,417,743					9
636 ACSR								10
636 ACSR	119,332	1,790,435	1,909,767					11
336.4 ACSR	23,022	397,715	420,737					12
556.5 ACSR 18/1								13
336.4 ACSR								14
636 ACSR	136,682	1,370,995	1,507,677					15
636 ACSR								16
636 ACSR	236,419	1,834,732	2,071,151					17
600 CU PIPT		774,047	774,047					18
600 CU PIPT	2	637,129	637,131					19
636 ACSR								20
636 ACSR	48,503	553,806	602,309					21
636 AA	609,590	1,716,584	2,326,174					22
636 ACSR	356,228	2,529,395	2,885,623					23
636 ACSR	93,917	544,710	638,627					24
636 ACSR								25
636 ACSR	137,166	674,000	811,166					26
636 ACSR	93,908	1,635,439	1,729,347					27
336.4 ACSR								28
636 ACSR	234,782	2,585,690	2,820,472					29
336.4 ACSR								30
636 ACSR	22,166	720,728	742,894					31
636 ACSR								32
636 ACSR	314,712	1,731,400	2,046,112					33
								34
								35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
636 ACSR								1
636 ACSR								2
636 ACSR	959,032	4,594,785	5,553,817					3
1272 ACSR								4
636 ACSR	185,489	901,459	1,086,948					5
600 CU PIPT								6
636 ACSR	69,573	2,041,637	2,111,210					7
600 CU PIPT	91,627	1,031,476	1,123,103					8
636 ACSR								9
636 ACSR								10
636 ACSR	497,262	2,417,958	2,915,220					11
636 ACSR								12
636 ACSR								13
636 AA								14
1250 CU PIPT	11,703	909,031	920,734					15
954 ACSR	64,446	564,718	629,164					16
636 AA								17
336.4 ACSR	79,765	496,425	576,190					18
636 ACSR								19
636 ACSR	90,857	729,292	820,149					20
336.4 ACSR								21
636 ACSR	19,285	3,880,729	3,900,014					22
1272 ACSR								23
1272 ACSR								24
1272 ACSR		486,012	486,012					25
1272 ACSR	330,140	415,091	745,231					26
1272 ACSR	291,072	698,177	989,249					27
600 CU PIPT	786	265,320	266,106					28
1272 ACSR	18,282	1,214,748	1,233,030					29
1272 ACSR	655,122	2,600,886	3,256,008					30
1272 ACSR								31
1272 ACSR								32
1272 ACSR	320,725	942,172	1,262,897					33
636 AA	68,610	1,094,147	1,162,757					34
								35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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1272 ACSR								1
336.4 ACSR								2
2500 ALUM	14,717	2,190,616	2,205,333					3
1272 ACSR								4
636 ACSR								5
636 AA	12,669	306,092	318,761					6
636 ACSR								7
636 ACSR								8
1272 ACSR								9
336.4 ACSR	495,915	652,871	1,148,786					10
1272 KCM								11
636 ACSR	64,779	664,762	729,541					12
636 ACSR	39,429	421,208	460,637					13
636 AA	112,487	1,452,614	1,565,101					14
636 ACSR	180,778	1,421,676	1,602,454					15
636 AA	4,790	298,258	303,048					16
336.4 ACSR	75,476	81,713	157,189					17
636 AA		20,701	20,701					18
636 AA	155,011	881,264	1,036,275					19
2500 CU PIPT								20
636 AA	17,716	1,344,121	1,361,837					21
636 ACSR	27,349	897,921	925,270					22
636 ACSR	37,272	1,452,760	1,490,032					23
636 AA								24
1259 CU PIPT		818,625	818,625					25
1272 KCM								26
636 ACSR	224,722	1,019,093	1,243,815					27
636 ACSR	288,209	4,540,683	4,828,892					28
336.4 ACSR								29
336.4 ACSR	72,907	2,060,328	2,133,235					30
636 ACSR								31
636 ACSR								32
336 ACSR	95,298	310,036	405,334					33
								34
								35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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336.4 ACSR								1
636 ACSR	111,897	643,413	755,310					2
556.5 ACSR 18.1								3
636 ACSR								4
636 ACSR	66,964	335,716	402,680					5
636 ACSR	36,779	222,684	259,463					6
600 CU PIPT	9,105	1,200,257	1,209,362					7
636 ACSR								8
636 ACSR	88,501	2,297,251	2,385,752					9
636 ACSR	472,319	5,075,671	5,547,990					10
636 ACSR								11
636 ACSR								12
636 ACSR	30,427	912,264	942,691					13
954 ACSR	246,919	1,317,661	1,564,580					14
954 ACSR								15
1272 ACSR	157,798	134,946	292,744					16
1272 ACSR		555,336	555,336					17
1272 ACSR	132,616	556,258	688,874					18
1272 ACSR								19
636 ACSR								20
1272 ACSR								21
1272 ACSR								22
1272 ACSR	457,078	2,914,944	3,372,022					23
1250 CU PIPT		1,179,534	1,179,534					24
983.1 ACAR	56,822	1,046,998	1,103,820					25
636 ACSR								26
636 ACSR								27
336 ACSR	35,117	1,300,110	1,335,227					28
983.1 ACSR	268,205	525,039	793,244					29
954 ACSR								30
2750 CU KCM	544,816	2,932,159	3,476,975					31
600 CU PIPT	174,545	1,186,767	1,361,312					32
636 ACSR		359,788	359,788					33
600 CU PIPT		371,400	371,400					34
636 ACSR		34,138	34,138					35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
636 ACSR	31,625	483,466	515,091					1
565.5 ACSR 18/1		1,555	1,555					2
556.5 ACSR 18/1		2,421	2,421					3
	39,431		39,431					4
								5
2-954 ACRS	414,014	746,926	1,160,940					6
2-954 ACRS	495,504	976,206	1,471,710					7
	7,268,490	61,491,031	68,759,521					8
								9
				11,773	842,455		854,228	10
				34,537	2,471,314		2,505,851	11
				62,733	4,488,929		4,551,662	12
				71,541	5,119,108		5,190,649	13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	/ /	2012/Q4

FOOTNOTE DATA

Schedule Page: 422.9 Line No.: 1 Column: a

422.9 Line 1
On December 31, 2011, AEP affiliates Columbus Southern Power Company and Ohio Power Company were merged into one company, Ohio Power Company.

422.9 Line 30
TRANSMISSION LINE STATISTICS:

Transmission Lines are co-owned with Duke Energy, The Dayton Power and Light Company (DP&L) and Respondent (OPCO). Statistics represent total line miles, but dollar amounts represent the Respondent's share only. The co-owners are not associated companies.

Ownership percentages are as follows for the respective footnotes:

Company	Duke Energy	DP&L	OPCO
Footnote:			
(A)	30%	35%	35%
(B)	33-1/3%	33-1/3%	33-1/3%
(C)	16.86%	16.86%	66.28%
(D)	8.43%	8.43%	83.14%
(E)	28%	36%	36%
(F)	17.5%	22.5%	60%

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	NO LINES ADDED						
2							
3	LINES ALTERED:						
4	0235 - WEST MILLERSPORT	HEATH	2.90	STEEL		1	1
5							
6							
7							
8							
9							
10							
11							
12							
13							
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36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		2.90			1	1

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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
1590KCM	ACSR		138		2,843,577	452,268		3,295,845	4
									5
									6
									7
									8
									9
									10
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									42
									43
					2,843,577	452,268		3,295,845	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	OHIO POWER COMPANY				
2	ACADEMIA-OH	T	138.00	69.00	13.00
3		T	69.00		
4	ADA-OH	D	69.00	13.09	
5	ANCHOR HOCKING (OP)-OH	D	69.00	12.00	
6		D	69.00	4.00	
7		D	34.50	4.00	
8	ANTWERP-OH	D	69.00	12.47	
9	APPLE CREEK-OH	D	138.00	13.09	
10	ASH AVENUE-OH	D	34.50	13.09	
11	AUGLAIZE-OH	D	69.00	13.09	
12	AVONDALE-OH	D	69.00	12.00	
13	BANNOCK ROAD-OH	D	69.00	13.09	
14	BARNESVILLE-OH	D	69.00	13.09	
15	BEALL AVENUE-OH	D	69.00	13.09	
16		D	69.00	4.00	
17	BEAVER-OH	D	69.00	34.50	12.00
18		D	69.00	12.00	
19	BELDEN VILLAGE-OH	D	138.00	13.09	
20	BERLIN (OP)-OH	D	69.00	34.50	
21		D	69.00	13.09	
22	BERWICK-OH	D	69.00	13.09	
23	BILLIAR-OH	D	69.00	13.09	
24	BLACKJACK ROAD-OH	D	69.00	12.00	
25	BLISS PARK-OH	D	69.00	13.09	
26	BLUFFTON (OP)-OH	D	34.50	13.09	
27		D	34.50		
28	BOLIVAR-OH	D	138.00	36.20	
29	BRIDGEPORT-OH	D	69.00	13.09	
30		D	69.00	4.00	
31	BRIDGEVILLE-OH	D	138.00	13.09	
32	BROOM ROAD-OH	D	69.00	13.09	
33		D	69.00		
34	BUCKLEY ROAD-OH	T	138.00	69.50	13.09
35	BUCYRUS-OH	D	69.00	13.09	
36		D	69.00		
37	BUCYRUS CENTER-OH	T	138.00	69.50	13.09
38		T	69.00	13.09	
39	BYESVILLE-OH	D	69.00	12.00	
40	CADIZ-OH	D	69.00	13.09	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	CALCUTTA-OH	D	69.00	13.09	
2	CALDWELL-OH	T	138.00	34.50	
3		T	138.00	13.09	
4	CALIFORNIA-OH	D	69.00	13.09	
5	CAMBRIDGE-OH	D	34.50	12.00	
6		D	34.50	4.00	
7		D	34.50		
8	CANAL ROAD-OH	T	138.00	69.00	34.50
9		T	69.00	23.00	
10	CANTON CENTRAL-OH	T	345.00	137.50	13.14
11	CARROLLTON-OH	D	138.00	13.09	
12	CENTER STREET-OH	D	69.00	12.00	
13	CENTRAL PORTSMOUTH-OH	T	138.00	69.00	34.50
14		T	69.00	7.20	
15	CHATFIELD-OH	T	138.00	69.50	13.09
16	CHERRY AVENUE-OH	D	69.00	12.00	
17	CLIFTMONT AVENUE-OH	D	69.00	12.00	
18	COLUMBUS GROVE-OH	D	69.00	12.47	
19	CONESVILLE PREPARATION PLANT-OH	D	138.00	13.09	
20	COOPERMILL-OH	D	69.00	13.09	
21		D	69.00	4.00	
22		D	69.00		
23	COSHOCTON-OH	D	69.00	12.00	
24		D	69.00	4.00	
25		D	69.00		
26	CRESTWOOD-OH	D	34.50	13.09	
27	CROOKSVILLE-OH	T	138.00	69.00	12.00
28		T	69.00	13.09	
29		T	69.00	4.00	
30	DELPHOS-OH	D	69.00	13.09	
31	DENNISON-OH	T	69.00	36.20	
32		T	69.00	13.09	
33		T	69.00		
34		T	34.50	4.00	
35	DOGWOOD RIDGE-OH	D	138.00	13.09	
36	DON MARQUIS (OP-CS) (OVEC)-OH	T	765.00	345.00	34.50
37		T	345.00		
38		T	345.00	137.50	13.80
39	DOW CHEMICAL-HANGING ROCK-OH	D	69.00	12.00	
40	DRESDEN-OH	D	69.00	12.00	

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.
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	DUNKIRK (OP)-OH	T	69.00	36.20	
2		T	69.00	13.09	
3		T	69.00		
4	EAST AMSTERDAM-OH	T	138.00	69.00	12.00
5	EAST BEAVER-OH	T	138.00	69.00	34.50
6	EAST CAMBRIDGE-OH	T	69.00	34.50	
7		T	69.00		
8	EAST CANTON-OH	D	69.00	13.09	
9	EAST FREMONT-OH	D	69.00	13.09	
10		D	69.00	4.36	
11	EAST LANCASTER-OH	D	69.00	12.00	
12		D	69.00		
13	EAST LEIPSIC-OH	T	138.00	69.50	7.20
14		T	138.00		
15		T	69.00	36.20	
16	EAST LIMA-OH	T	345.00	137.50	13.80
17		T	345.00	137.50	13.20
18		T	345.00	137.50	13.14
19		T	138.00	69.50	13.09
20		T	138.00		
21	EAST LIVERPOOL-OH	T	138.00	70.50	13.09
22		T	69.00		
23	EAST LOGAN-OH	D	69.00	12.00	
24		D	69.00		
25	EAST NEWARK-OH	D	69.00	13.09	
26		D	69.00	4.00	
27	EAST OTTAWA-OH	T	69.00	13.09	
28		T	69.00		
29	EAST POINTE-OH	D	138.00	13.09	
30	EAST PROCTORVILLE-OH	D	138.00	34.50	
31	EAST SIDE (LIMA)-OH	D	138.00	36.20	
32		D	34.50	4.33	
33	EAST SPARTA-OH	D	23.00	13.09	
34		D	23.00	12.00	
35		D	23.00		
36	EAST TIFFIN-OH	D	69.00	13.09	
37	EAST UNION-OH	D	69.00	13.09	
38	EAST WILLARD-OH	D	69.00	13.09	
39					
40					

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Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	EAST WOOSTER-OH	T	138.00	69.50	13.09
2		T	138.00	24.14	
3		T	138.00	13.09	
4		T	138.00		
5	EAST ZANESVILLE-OH	T	138.00	69.00	13.00
6		T	138.00	69.00	12.00
7		T	138.00		
8	EASTON STREET-OH	D	69.00	13.09	
9	EASTOWN ROAD-OH	D	138.00	13.20	
10		D	138.00	13.09	
11	EIGHTEEN STREET HEIGHTS-OH	D	69.00	13.09	
12		D	69.00	12.00	
13	ELIZABETH STREET-OH	D	34.50	4.36	
14	ETNA-OH	D	69.00	34.50	
15		D	69.00	13.09	
16	FAIRCREST STREET-OH	D	138.00	13.09	
17	FAIRDALE-OH	D	69.00	12.00	
18	FAIRFIELD-OH	D	69.00	4.36	
19	FINDLAY-OH	D	34.50	13.09	
20		D	34.50		
21	FINDLAY CENTER-OH	T	138.00	69.50	35.00
22		T	34.50	13.09	
23		T	34.50		
24	FOREST (OP)-OH	T	69.00	23.99	4.16
25		T	69.00	23.50	
26		T	69.00	13.09	
27		T	69.00		
28	FOSTORIA CENTRAL-OH	T	345.00	137.50	13.80
29	FREDERICKTOWN-OH	D	69.00	13.09	
30	FREMONT (OP)-OH	T	138.00	69.50	13.09
31		T	69.00		
32	FREMONT CENTER-OH	T	138.00	70.50	13.09
33		T	138.00		
34		T	69.00	13.09	
35		T	69.00		
36	GAMBIER-OH	D	69.00	12.00	
37	GAVIN-OH	T	765.00	69.00	
38		T	138.00		
39		T	138.00	69.00	12.00
40		T	69.00	12.00	

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

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	GLENMOOR-OH	D	69.00	12.00	
2	GRANVILLE-OH	D	69.00	13.09	
3		D	69.00	12.00	
4	GREELY-OH	D	69.00	13.09	
5		D	69.00	4.36	
6	GREENLAWN-OH	T	138.00	69.50	13.09
7	GREER-OH	T	69.00	35.00	
8		T	34.50		
9		T	34.50	12.00	
10	HAMMONDSVILLE-OH	T	69.00	23.00	
11		T	69.00		
12	HANGING ROCK-OH	T	765.00		
13		T	138.00	69.00	34.50
14	HARPSTER-OH	T	69.00	35.00	
15	HAVILAND-OH	T	138.00	69.50	13.09
16		T	138.00	13.09	
17	HEATH-OH	T	138.00	69.00	12.00
18		T	138.00	34.50	
19		T	69.00	4.00	
20	HIGHLAND AVENUE-OH	D	69.00	13.09	
21	HIGHLAND TERRACE-OH	D	69.00	13.09	
22	HOCKING-OH	T	138.00	69.00	12.00
23	HOWARD-OH	T	138.00	69.50	11.00
24		T	138.00		
25		T	69.00	13.09	
26		T	69.00		
27	HUGHES STREET-OH	D	69.00	4.36	
28	KALIDA-OH	T	69.00	35.00	
29		T	69.00	13.09	
30		T	69.00		
31	KAMMER 138KV-WV	T	138.00	34.50	
32		T	138.00		
33	KAMMER 345KV-WV	T	345.00	137.50	13.80
34	KAMMER 400 YARD-WV	T	765.00	345.00	34.50
35	KAMMER 765-500KV-WV	T	765.00		
36	KENTON-OH	D	69.00	36.20	
37		D	69.00		
38	LANCASTER-OH	D	69.00	12.00	
39		D	69.00	4.00	
40		D	69.00		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.
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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	LANCASTER JUNCTION-OH	D	69.00	13.09	
2		D	69.00	12.00	
3	LEESVILLE (OP)-OH	D	69.00	13.09	
4	LEIPSIC-OH	D	69.00	13.09	
5	LINDEN AVENUE-OH	D	69.00	12.00	
6		D	69.00	4.00	
7		D	69.00		
8	LOCK SEVENTEEN-OH	D	69.00	13.00	
9		D	69.00		
10	LOUISVILLE-OH	D	69.00	12.00	
11	MAHONING ROAD-OH	D	69.00	12.00	
12	MALVERN-OH	T	138.00	69.00	12.00
13		T	138.00	23.00	12.00
14		T	23.00	12.00	
15	MARTINS FERRY-OH	D	69.00	12.00	
16	MARTINSBURG ROAD-OH	D	69.00	13.09	
17	MARYSVILLE-OH	T	765.00		
18		T	765.00	345.00	34.50
19		T	765.00	345.00	12.00
20	MAULE ROAD-OH	D	69.00	13.09	
21	MCCOMB (OP)-OH	D	34.50	13.09	
22	MEIGS NO. 1-OH	D	138.00	34.50	
23	MEIGS NO. 2-OH	D	138.00	34.50	
24	MEMORIAL DRIVE-OH	D	69.00	13.09	
25	MILES AVENUE-OH	D	138.00	13.09	
26	MILL STREET-OH	D	69.00	12.00	
27	MILLBROOK PARK-OH	T	138.00	69.00	34.50
28		T	138.00	34.50	11.00
29		T	138.00		
30		T	34.50	12.00	
31	MILLWOOD-OH	D	138.00	13.09	
32	MINERVA-OH	D	69.00	13.09	
33	MINFORD-OH	D	69.00	12.00	
34	MONROE STREET-OH	D	69.00	12.00	
35	MOUNT VERNON (OP)-OH	D	69.00	12.00	
36		D	69.00	4.00	
37	MUSKINGUM RIVER 138KV-OH	T	345.00	141.00	13.20
38		T	345.00	137.50	13.80
39		T	138.00	69.00	13.09
40	NEGLEY-OH	D	138.00	13.09	

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.
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.
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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	NEW LEXINGTON-OH	D	69.00	13.09	
2		D	69.00		
3	NEW LIBERTY-OH	T	138.00	70.50	36.20
4		T	138.00	34.50	
5		T	138.00	13.09	
6		T	138.00		
7		T	34.50		
8	NEW PHILADELPHIA-OH	D	69.00	36.20	
9		D	69.00		
10	NEWARK-OH	D	69.00	4.36	
11		D	69.00		
12	NEWARK CENTER-OH	T	138.00	69.00	12.00
13	NEWCOMERSTOWN-OH	T	138.00	69.00	12.00
14		T	69.00	34.50	12.00
15		T	69.00		
16	NORTH BALTIMORE-OH	D	34.50	13.09	
17		D	34.50		
18	NORTH BELLVILLE-OH	T	138.00	69.50	13.09
19		T	69.00		
20	NORTH CAMBRIDGE-OH	D	69.00	13.09	
21		D	69.00	4.36	
22	NORTH CANTON-OH	D	69.00	13.09	
23		D	69.00		
24	NORTH COSHOCTON-OH	T	69.00	34.50	12.00
25		T	69.00	12.00	
26		T	69.00		
27	NORTH CROWN CITY-OH	T	138.00	69.00	13.20
28	NORTH DELPHOS-OH	T	138.00	70.50	36.20
29		T	69.00		
30	NORTH END FOSTORIA-OH	D	69.00	13.09	
31	NORTH FINDLAY-OH	T	138.00	69.50	35.00
32		T	138.00	35.00	
33		T	138.00		
34		T	34.50		
35	NORTH FREMONT-OH	D	69.00	13.09	
36	NORTH HEBRON-OH	D	69.00	34.50	
37	NORTH HICKSVILLE-OH	D	69.00	13.09	
38	NORTH LEIPSIC-OH	D	69.00	13.09	
39	NORTH LEXINGTON-OH	D	138.00	13.09	
40	NORTH MUSKINGUM-OH	T	138.00	69.00	12.00

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Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	NORTH NEWARK-OH	T	138.00	69.00	4.00
2		T	138.00	13.09	
3		T	138.00		
4		T	69.00	12.00	
5		T	69.00	4.00	
6		T	69.00		
7	NORTH PORTSMOUTH-OH	T	138.00	69.00	34.50
8	NORTH PROCTORVILLE-OH	T	765.00	138.00	13.80
9	NORTH SPENCERVILLE-OH	D	69.00	13.09	
10	NORTH UPPER SANDUSKY-OH	D	69.00	13.09	
11	NORTH WALDO-OH	T	138.00	69.00	7.20
12		T	69.00	13.09	
13	NORTH WELLSVILLE-OH	D	69.00	12.00	
14		D	69.00		
15	NORTH WILLARD-OH	D	69.00	13.09	
16		D	69.00		
17	NORTH WOODCOCK-OH	T	138.00	69.50	35.50
18		T	34.50		
19	NORTH WOOSTER-OH	D	69.00	12.00	
20	NORTH ZANESVILLE-OH	D	138.00	13.09	
21	NORTHEAST CANTON-OH	T	138.00	69.00	12.00
22		T	69.00		
23	NORTHEAST FINDLAY-OH	T	138.00	36.20	
24	NORTHWEST LIMA-OH	D	138.00	13.09	
25	NORVAL PARK-OH	D	69.00	4.00	
26	OAKLAND-OH	D	69.00	12.00	
27	OAKWOOD ROAD-OH	D	69.00	12.00	
28	OERTELS CORNERS-OH	D	69.00	12.00	
29	OHIO CENTRAL-OH	T	345.00	137.50	13.12
30		T	138.00	70.50	36.20
31		T	138.00	69.00	12.00
32		T	138.00	69.00	4.00
33		T	138.00	13.09	
34		T	69.00	34.50	
35		T	69.00	12.00	
36		T	23.00	12.00	
37		T	23.00	4.00	
38	PACKARD-OH	D	138.00	13.20	
39	PAULDING-OH	D	69.00	13.09	
40		D	69.00		

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PEKIN-OH	T	69.00	23.00	
2		T	69.00	13.09	
3		T	69.00		
4	PIEDMONT AVENUE-OH	D	26.00	4.00	
5	PITTSBURGH AVENUE-OH	D	69.00	13.09	
6	PLEASANT STREET-OH	T	69.00	34.50	
7		T	69.00	13.09	
8		T	69.00		
9	PLYMOUTH HEIGHTS-OH	D	69.00	12.00	
10	POWELSON-OH	D	138.00	13.09	
11	PROMWAY-OH	D	138.00	13.09	
12	QUARRY ROAD-OH	D	69.00	12.00	
13	RACINE HYDRO-OH	T	69.00	13.09	
14	RALSTON-OH	D	69.00	12.00	
15	REEDURBAN-OH	T	138.00	69.50	13.09
16		T	138.00	13.09	
17	RIVERVIEW (OP)-OH	D	69.00	13.09	
18		D	69.00	4.36	
19		D	69.00		
20	ROBB AVENUE-OH	D	34.50	4.00	
21	ROCKHILL (OP)-OH	T	138.00	35.00	
22		T	138.00	34.65	11.00
23		T	138.00	13.09	
24		T	34.50		
25	ROSEMOUNT-OH	D	69.00	34.50	
26		D	69.00	13.09	
27	RUTLAND-OH	T	138.00	34.50	
28	SAINT CLAIR AVENUE (OP)-OH	D	69.00	13.09	
29	SAVANNAH AVENUE-OH	D	69.00	22.90	13.09
30	SCHOENBRUNN-OH	D	69.00	12.00	
31	SCHROYER AVENUE-OH	T	69.00	23.00	13.09
32		T	69.00	13.09	
33		T	69.00	4.00	
34		T	69.00		
35	SCIOTO TRAIL (OP)-OH	D	34.50	13.09	
36	SEROCO AVENUE-OH	D	69.00	4.00	
37	SHADYSIDE-OH	D	69.00	13.09	
38	SHARON VALLEY-OH	D	69.00	13.09	
39	SHARP ROAD-OH	T	138.00	69.00	12.00
40		T	69.00		

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SHAWNEE ROAD-OH	T	138.00	69.50	35.00
2		T	138.00	13.09	
3	SHREVE-OH	D	69.00	13.09	
4	SOMERTON-OH	T	138.00	69.00	12.00
5	SOUTH BALTIMORE-OH	T	138.00	69.00	4.00
6	SOUTH BELMONT-OH	D	69.00	13.09	
7	SOUTH BERWICK-OH	T	345.00	68.80	13.09
8	SOUTH CADIZ-OH	T	138.00	69.00	12.00
9		T	69.00	12.00	
10		T	69.00		
11	SOUTH CAMBRIDGE-OH	T	69.00	34.50	
12		T	69.00	34.50	12.00
13		T	69.00		
14	SOUTH CANTON 345KV-OH	T	345.00	137.50	35.00
15	SOUTH CANTON 765KV-OH	T	765.00	345.00	34.50
16	SOUTH COSHOCTON-OH	T	138.00	69.00	12.00
17		T	138.00	36.00	7.20
18		T	138.00	13.09	
19		T	69.00	34.50	12.00
20		T	34.50	12.00	
21	SOUTH CUMBERLAND-OH	T	138.00	69.00	34.50
22		T	138.00	25.00	
23	SOUTH DELPHOS-OH	D	69.00	13.09	
24	SOUTH FINDLAY-OH	D	34.50	13.09	
25		D	34.50		
26	SOUTH GRANVILLE-OH	D	69.00	13.09	
27	SOUTH HICKSVILLE-OH	T	138.00	69.50	13.09
28		T	69.00		
29	SOUTH KENTON-OH	T	138.00	69.00	
30		T	2.50		
31	SOUTH LANCASTER-OH	T	138.00	69.00	34.50
32		T	138.00	69.00	12.00
33	SOUTH LUCASVILLE-OH	D	138.00	13.09	
34	SOUTH MARTINS FERRY-OH	D	69.00	13.09	
35	SOUTH MILLERSBURG-OH	T	138.00	35.00	7.20
36		T	34.50		
37	SOUTH NEWARK-OH	D	69.00	12.00	
38					
39					
40					

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

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1	SOUTH POINT-OH	T	138.00	69.00	34.50
2		T	138.00	34.50	
3		T	138.00		
4		T	34.50	12.00	
5	SOUTH SIDE LIMA-OH	D	34.50	13.09	
6		D	34.50	4.36	
7	SOUTH TIFFIN-OH	T	138.00	69.30	6.90
8	SOUTH TORONTO-OH	T	138.00	69.50	13.09
9	SOUTH VAN WERT-OH	D	69.00	13.09	
10		D	69.00	4.36	
11		D	69.00		
12	SOUTHEAST CANTON-OH	T	345.00	137.50	34.50
13	SOUTHEAST LOGAN-OH	D	69.00	12.00	
14	SOUTHWEST LIMA-OH	T	345.00	138.00	13.80
15		T	345.00	137.50	13.80
16		T	345.00	137.50	13.12
17		T	138.00		
18	ST RITAS HOSP-OH	D	34.50	4.16	
19	STADIUM PARK-OH	D	69.00	13.09	
20		D	69.00	12.00	
21		D	69.00		
22	STANLEY COURT-OH	T	69.00	13.09	
23		T	69.00		
24	STERLING-OH	T	138.00	33.00	
25		T	138.00	33.00	11.00
26		T	34.50		
27	STEUBENVILLE-OH	T	138.00	69.00	12.00
28	STONE STREET-OH	D	69.00	13.09	
29		D	69.00	4.36	
30	STONY HOLLOW-OH	D	69.00	13.09	
31	STRASBURG-OH	D	138.00	36.20	
32	SUGARCREEK TERMINAL-OH	D	138.00	13.09	
33	SUMMERFIELD-OH	T	138.00	69.00	12.00
34	SUMMERHILL-OH	D	69.00	13.09	
35	SUNNYSIDE-OH	T	138.00	23.00	
36		T	138.00	23.00	6.90
37		T	138.00	13.09	
38		T	138.00		
39		T	23.00		
40	SUNSET BOULEVARD-OH	D	69.00	13.09	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SWITZER-OH	T	138.00	69.00	12.00
2	THAYER ROAD-OH	D	138.00	13.09	
3	THIRD STREET-OH	D	69.00	13.09	
4		D	23.00	4.33	
5		D	23.00	4.00	
6	THORNVILLE-OH	D	69.00	13.09	
7	TIDD 138KV-OH	T	138.00	13.09	
8		T	138.00		
9	TIDD 345KV-OH	T	345.00	141.00	13.20
10		T	345.00	137.50	13.80
11		T	138.00	13.80	
12		T	34.50	4.00	
13	TIDD 69KV-OH	T	138.00	69.00	34.50
14		T	69.00	12.00	
15	TIFFIN CENTER-OH	T	138.00	69.50	13.09
16	TIFFIN TAP-OFF-OH	D	69.00	13.09	
17		D	69.00	4.36	
18	TILTONSVILLE-OH	T	138.00	69.00	12.00
19		T	69.00	13.09	
20		T	69.00		
21	TIMKEN-OH	T	138.00	24.14	
22	TIMKEN MERCY-OH	D	69.00	4.00	
23	TORONTO-OH	D	69.00	13.09	
24	TORREY-OH	T	138.00	69.00	12.00
25		T	138.00	23.00	11.00
26		T	138.00		
27		T	69.00	13.09	
28		T	69.00		
29		T	23.00	12.00	
30	TWO RIDGES-OH	D	69.00	12.00	
31	UPPER SANDUSKY-OH	D	69.00	13.09	
32		D	69.00		
33	UTICA (OP)-OH	D	69.00	13.09	
34	VAN WERT-OH	D	69.00	13.09	
35		D	69.00	4.36	
36		D	69.00		
37	WAGENHALS-OH	T	138.00	70.50	13.09
38		T	138.00	69.00	23.00
39		T	138.00	23.50	7.20
40		T	138.00		

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1	WAKEFIELD-OH	T	138.00	13.09	
2	WAYVIEW-OH	T	138.00	69.00	12.00
3		T	138.00	13.09	
4	WEST BELLAIRE-OH	T	345.00	137.50	13.12
5		T	138.00	69.00	12.00
6	WEST CAMBRIDGE-OH	T	138.00	69.00	13.09
7		T	138.00	36.20	
8		T	138.00		
9	WEST CANTON-OH	T	138.00	69.50	13.09
10		T	138.00	36.20	
11		T	138.00	13.09	
12		T	138.00		
13		T	69.00	36.20	
14		T	69.00		
15	WEST COSHOCTON-OH	T	138.00	69.00	13.09
16	WEST DOVER-OH	T	138.00	69.50	13.09
17	WEST END FOSTORIA-OH	T	138.00	69.50	13.09
18		T	138.00		
19		T	69.00	4.36	
20		T	69.00	4.16	
21		T	69.00		
22	WEST GRANVILLE-OH	D	69.00	12.00	
23		D	69.00		
24	WEST HEBRON-OH	T	138.00	69.00	34.50
25		T	34.50	34.50	
26		T	34.50		
27	WEST HICKSVILLE-OH	D	69.00	13.09	
28	WEST LANCASTER-OH	T	138.00	69.00	12.00
29		T	138.00		
30		T	69.00		
31	WEST LIMA-OH	T	138.00	35.00	
32		T	138.00		
33	WEST LOGAN-OH	D	69.00	12.00	
34	WEST LOUISVILLE-OH	D	69.00	12.00	
35		D	69.00		
36	WEST MELROSE-OH	D	34.50	13.09	
37	WEST MILLERSBURG-OH	D	138.00	69.00	34.50
38		D	138.00	36.20	
39	WEST MILLERSPORT-OH	T	345.00	137.50	13.80
40		T	138.00	70.50	13.09

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1	WEST MOULTON-OH	T	138.00	70.50	36.20
2		T	69.00	13.09	
3	WEST MOUNT VERNON-OH	T	138.00	69.00	4.00
4		T	138.00		
5		T	69.00		
6	WEST NEW PHILADELPHIA-OH	T	138.00	69.00	12.00
7		T	138.00	34.50	4.00
8		T	138.00	13.09	
9		T	138.00		
10	WEST TORONTO-OH	D	69.00	13.09	
11	WEST TRINWAY-OH	D	138.00	13.09	
12	WEST VAN WERT-OH	T	69.00	35.00	
13	WEST WOOSTER-OH	D	69.00	12.00	
14		D	69.00		
15	WHIRLPOOL (OP)-OH	D	34.50	13.09	
16	WILLISTON AVENUE-OH	D	69.00	13.09	
17	WINTERSVILLE-OH	D	69.00	12.00	
18	WOODLAWN (OP)-OH	D	138.00	13.09	
19	WOOSTER-OH	T	138.00	69.50	13.09
20		T	138.00	24.14	
21		T	138.00	13.09	
22		T	138.00		
23	ZANESVILLE-OH	T	138.00	69.00	12.00
24		T	138.00	13.09	
25		T	138.00		
26					
27	174 STATIONS UNDER 10 MVA	T/D			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	COLUMBUS SOUTHERN POWER				
2	ADAMS (CSP)-OH	T	138.00	69.00	13.09
3		T	69.00		
4	ADDISON-OH	T	138.00	69.00	13.00
5		T	69.00	12.00	
6		T	69.00		
7		T	13.20		
8	ADENA-OH	D	69.00	13.09	
9	ASTOR-OH	D	138.00	13.80	13.80
10		D	13.80		
11	BEATTY ROAD-OH	T	345.00	137.50	13.80
12		T	138.00	69.00	13.80
13		T	138.00	69.00	13.00
14		T	138.00	36.20	
15		T	138.00	13.80	
16		T	13.20		
17	BELPRE-OH	D	138.00	13.09	
18	BERKSHIRE-OH	D	138.00	35.40	13.80
19		D	34.50		
20		D	34.50		
21	BERLIN (CSP)-OH	D	69.00	13.00	
22		D	69.00	12.00	
23		D	13.20		
24	BETHEL ROAD-OH	T	138.00	69.50	13.09
25		T	138.00	13.80	13.80
26		T	138.00		
27		T	13.20		
28	BEXLEY-OH	T	138.00	40.00	13.80
29		T	138.00	39.40	13.80
30		T	138.00	13.80	13.80
31		T	46.00		
32		T	13.20		
33					
34					
35					
36					
37					
38					
39					
40					

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1	BIXBY-OH	T	345.00	138.00	35.00
2		T	345.00	138.00	34.50
3		T	138.00	13.80	
4		T	138.00	13.80	13.80
5		T	138.00	13.09	
6		T	69.00	13.80	
7		T	69.00	13.20	
8		T	69.00	13.09	
9		T	69.00	4.36	
10		T	40.00	14.50	
11		T	40.00	13.80	
12		T	34.50	4.00	
13		T	23.00	13.09	
14		T	13.20		
15	BLACKLICK-OH	D	138.00	35.40	13.80
16		D	34.50		
17		D	13.80		
18	BLENDON-OH	D	138.00	35.40	13.80
19		D	138.00	34.50	13.80
20	BRIGGSDALE-OH	D	40.00	13.80	
21		D	13.80		
22	BROOKSIDE (CS)-OH	D	138.00	13.80	
23		D	138.00	13.09	
24	BUCKSKIN-OH	D	69.00	12.00	
25	CAMP SHERMAN-OH	D	69.00	13.09	
26		D	69.00	13.00	
27	CANAL STREET-OH	D	138.00	13.80	13.80
28		D	13.80		
29		D	13.20		
30	CENTERBURG-OH	D	138.00	35.40	13.80
31	CIRCLEVILLE-OH	T	138.00	69.00	13.20
32		T	138.00	13.20	
33		T	138.00		
34		T	69.00		
35		T	13.20		
36	CLARK STREET-OH	D	69.00		
37		D	69.00	12.00	
38		D	69.00		
39	CLINTON-OH	D	138.00	13.80	13.80
40	COLUMBIA(CS)-OH	D	40.00	13.20	

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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	CONESVILLE PLANT-OH	T	345.00	138.00	34.50
2		T	138.00	70.73	13.20
3		T	138.00		
4	COOLVILLE (CS)-OH	D	69.00	13.20	
5	COPELAND-OH	D	69.00	13.20	
6		D	13.20		
7	CORNER-OH	D	138.00	13.09	
8	CORRIDOR-OH	T	345.00	138.00	34.50
9		T	345.00	138.00	13.80
10		T	138.00	34.50	13.80
11		T	138.00		
12	CORWIN-OH	D	138.00	13.09	
13	DAVIDSON (CS)-OH	D	138.00	13.80	
14		D	13.80		
15	DAVON-OH	D	69.00	13.20	
16	DELANO-OH	D	138.00	69.00	13.20
17		D	13.20	4.00	
18	DELAWARE (CSP)-OH	T	138.00	69.00	13.09
19		T	138.00	40.00	13.80
20		T	138.00	35.40	13.80
21		T	138.00	34.50	13.80
22		T	138.00	13.80	
23		T	138.00		
24		T	34.50		
25		T	13.20		
26	DUBLIN(CS)-OH	D	138.00	13.80	
27		D	13.80		
28	DUCK CREEK-OH	D	138.00	13.09	
29		D	23.00	13.09	
30	EAST BROAD STREET-OH	T	138.00	40.00	13.80
31		T	138.00	39.40	13.80
32		T	138.00		
33		T	40.00		
34		T	13.20		
35	ELK-OH	D	69.00	13.20	
36	ELLIOTT-OH	T	138.00	69.00	13.20
37	ETNA ROAD-OH	D	40.00	13.80	4.30
38		D	13.20		
39	FIFTH AVENUE-OH	D	138.00	39.40	13.80
40		D	13.80		

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1	GAHANNA-OH	D	138.00	35.40	13.80
2		D	138.00	34.50	13.80
3		D	138.00	13.80	
4		D	13.20		
5	GALLOWAY ROAD-OH	D	69.00	13.80	
6		D	13.20		
7	GAY STREET-OH	D	138.00	13.80	13.80
8		D	13.80		
9	GENOA-OH	T	138.00	70.50	13.80
10		T	138.00	69.00	12.00
11		T	138.00	34.50	13.80
12		T	138.00		
13		T	69.00		
14	GROVES ROAD-OH	T	138.00	40.00	13.80
15		T	138.00	13.80	
16		T	138.00	13.80	13.80
17		T	138.00		
18		T	46.00		
19		T	40.00	13.80	
20		T	13.80		
21	HALL-OH	D	138.00	13.80	
22		D	13.80		
23	HANERS-OH	D	69.00	13.09	
24		D	13.20		
25	HARMAR-OH	D	23.00	4.36	
26	HARMAR HILL-OH	D	138.00	13.09	
27	HARRISON-OH	T	138.00	69.00	13.80
28	HESS STREET-OH	D	138.00	13.80	
29		D	138.00		
30		D	13.80		
31	HIGHLAND (CS)-OH	D	69.00	13.20	
32		D	69.00		
33		D	13.20		
34	HILLIARD-OH	D	69.00	13.80	
35		D	69.00		
36		D	13.20		
37					
38					
39					
40					

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1	HUNTLEY-OH	T	138.00	69.50	13.09
2		T	138.00	13.80	
3		T	138.00		
4		T	69.00	13.80	
5		T	13.20		
6	HYATT-OH	T	345.00	137.50	13.80
7		T	138.00	35.40	13.80
8	IDAHO-OH	D	69.00	12.00	
9	JEFFERSON (CS)-OH	D	69.00	13.20	
10		D	13.20		
11	JUG STREET-OH	T	345.00	137.50	13.80
12		T	138.00	35.40	13.80
13	KARL ROAD-OH	D	138.00	13.80	13.80
14		D	13.80		
15		D	13.20		
16	KENNY-OH	D	138.00	13.80	13.80
17		D	13.20		
18	KIMBERLY-OH	D	138.00	13.09	
19	KIRK-OH	T	345.00	138.00	13.00
20		T	138.00	69.00	34.00
21		T	138.00	34.50	13.00
22		T	34.50		
23	LAYMAN-OH	D	138.00	13.09	
24	LAZELLE-OH	D	69.00	13.80	
25		D	13.20		
26	LEE-OH	D	69.00	12.00	
27		D	13.20		
28	LICK-OH	T	138.00	69.00	13.20
29		T	138.00		
30		T	69.00		
31		T	34.50	12.00	
32		T	13.20		
33	LINCOLN STREET-OH	D	69.00	13.80	
34	LINWORTH-OH	D	138.00	40.00	13.80
35		D	138.00	13.80	
36		D	13.20		
37	LIVINGSTON AVENUE-OH	D	40.00	13.00	
38	MADISON (CS)-OH	D	69.00	13.80	
39		D	69.00		
40					

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1	MALISZEWSKI 138 KV-OH	T	138.00	35.40	13.80
2		T	138.00	34.50	13.80
3		T	34.50		
4	MALISZEWSKI 765 KV-OH	T	765.00	138.00	13.80
5	MARION ROAD-OH	T	138.00	40.00	13.00
6		T	138.00	39.40	13.80
7		T	138.00		
8		T	40.00	13.00	
9		T	13.80	13.80	
10		T	13.20		
11	MCCOMB (CS)-OH	T	138.00	39.40	13.80
12		T	138.00		
13		T	13.20		
14	MEIGS (CS)-OH	D	69.00	13.09	
15		D	69.00	13.00	
16		D	69.00		
17		D	13.20		
18	MIFFLIN-OH	D	138.00	13.80	
19		D	13.20		
20	MILL CREEK (CSP)-OH	D	138.00	24.80	
21		D	138.00	13.09	
22	MORSE ROAD-OH	D	138.00	13.80	13.80
23		D	138.00		
24		D	13.20		
25	MOUND STREET-OH	D	138.00	13.80	13.80
26		D	13.80		
27	OSU-OH	D	138.00	13.80	
28		D	13.80		
29	PARK-OH	D	69.00	13.80	
30		D	13.20		
31	PARSONS-OH	D	40.00	13.80	
32		D	13.80		
33	PEACH MOUNT-OH	D	34.50	12.00	
34		D	13.20	4.00	
35	POLARIS-OH	D	138.00	35.40	13.80
36		D	34.50		
37	PORTERFIELD-OH	D	138.00	13.09	
38					
39					
40					

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1	POSTON-OH	T	138.00	69.00	13.40
2		T	138.00		
3		T	69.00	13.20	
4		T	69.00	13.09	
5		T	69.00	12.00	
6	RARDEN-OH	D	69.00	34.50	13.00
7	RAVEN-OH	D	69.00	13.20	
8	RENO-OH	D	138.00	13.09	
9	REYNOLDSBURG-OH	D	40.00	13.20	4.15
10		D	7.50		
11	RIO-OH	D	138.00	13.20	
12		D	13.20		
13	RIVERVIEW (CSP)-OH	D	138.00	13.80	
14		D	138.00		
15	ROBERTS-OH	T	345.00	138.00	34.50
16		T	345.00	137.50	13.80
17		T	138.00	13.80	
18		T	13.20		
19		T	13.20		
20	ROSS-OH	T	138.00	69.00	13.20
21		T	138.00	34.50	12.00
22		T	138.00		
23		T	69.00	13.00	
24		T	69.00		
25		T	13.20		
26	ROZELLE-OH	D	138.00	13.09	
27	SAINT CLAIR AVENUE (CS)-OH	D	138.00	40.00	13.00
28		D	138.00	13.80	13.80
29		D	138.00		
30	SARDINIA-OH	D	69.00	13.20	
31		D	13.20		
32	SAWMILL-OH	T	138.00	69.00	13.00
33		T	138.00	34.50	13.80
34		T	138.00	13.80	
35		T	138.00		
36	SCIOTO TRAIL (CS)-OH	D	138.00	13.20	7.24
37	SCIPPO-OH	D	138.00	13.09	
38					
39					
40					

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1	SEAMAN-OH	T	138.00	69.00	13.09
2		T	69.00	13.20	
3		T	69.00	13.09	
4		T	69.00		
5	SHANNON-OH	D	138.00	13.80	
6		D	13.80		
7	SLATE MILLS-OH	D	69.00	13.20	
8	STROUDS RUN-OH	T	138.00	69.00	13.20
9		T	138.00	69.00	12.00
10	SUNBURY-OH	D	34.50	13.20	4.15
11	TAYLOR-OH	D	138.00	34.50	13.80
12	TRABUE-OH	D	138.00	69.50	13.80
13		D	138.00	13.80	
14		D	13.80		
15	TRENT-OH	D	138.00	34.50	13.80
16	VIGO-OH	D	69.00	13.20	
17		D	69.00	13.09	
18	VINE-OH	D	138.00	13.80	
19		D	138.00	13.80	13.80
20		D	138.00		
21		D	13.20		
22	WAVERLY-OH	T	138.00	69.00	13.53
23		T	138.00	69.00	13.20
24		T	138.00		
25		T	13.20		
26	WEST-OH	D	46.00		
27		D	40.00	13.80	
28		D	40.00	13.20	
29	WESTERVILLE-OH	D	69.00	13.80	
30	WHITE ROAD-OH	D	138.00	13.80	
31	WILKESVILLE-OH	D	138.00	13.09	
32	WILSON ROAD-OH	T	138.00	39.40	13.80
33		T	138.00	13.80	13.80
34		T	138.00		
35		T	46.00		
36		T	13.20		
37	WOLF CREEK (CSP)-OH	T	138.00	133.20	7.20
38		T	138.00	23.60	
39		T	138.00	13.09	
40					

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1	ZUBER-OH	D	138.00	13.80	
2		D	13.80		
3					
4					
5	23 STATIONS UNDER 10 MVA	T/D			
6					
7	COMMONLY OWNED SUBSTATIONS				
8	#5 CORRIDOR/FRANKLIN CO. OH - NOTE A	UNATTENDED T	345.00		
9	#50 BECKJORD/NEW RICHMOND. OH - NOTE B	ATTENDED T	22.00	345.00	
10	#52 STUART/ADAMS CO. OH - NOTE A	SUPERVISORY			
11		CONTROL T	345.00	138.00	
12	SEE NOTE B	MONITOR T	22.00	345.00	
13	SEE NOTE A	MONITOR T	22.00	345.00	
14	SEE NOTE D	ATTENDED T	22.00	345.00	
15	SEE NOTE E	SUPERVISORY			
16		CONTROL T	345.00		
17	#52 PIERCE/CLERMONT CO. OH - NOTE B	ATTENDED T	345.00		
18	#50 GREEN/GAYTON. OH - NOTE B	SUPERVISORY			
19		CONTROL T	345.00		
20	#61 FOSTER/WARREN CO. OH - NOTE B	UNATTENDED T	345.00		
21	#62 ZIMMER/CLERMONT CO. OH - NOTE A & C	ATTENDED T	22.00	345.00	
22	#66 CONESVILLE/CONESVILLE. OH - NOTE A	ATTENDED T	22.00	345.00	
23	#71 BIXBY/GROVEPORT. OH - NOTE A	UNATTENDED T	345.00		
24	#74 BEATTY RD/GROVE CITY. OH - NOTES A & B	UNATTENDED T	345.00		
25	#241 TERMINAL/CINCINNATI. OH - NOTE C	ATTENDED T	345.00		
26	#243 PORT UNION/BUTLER CO. OH - NOTE C	ATTENDED T	345.00		
27	#245 DON MARQUIS/PIKE CO. OH - NOTE B	UNATTENDED T	345.00		
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
129	1					2
			STATCAP	1	18	3
20	1					4
6	1					5
6	1					6
3		1				7
11	1					8
10	1					9
20	1					10
14	2					11
16	2					12
20	1					13
11	1					14
20	1					15
8	1	1				16
11		1				17
20	1					18
42	2					19
13	1					20
20	1					21
20	1					22
19	2					23
20	1					24
20	1					25
11	1					26
			STATCAP	1	4	27
25	1					28
20	1					29
3	1					30
20	1					31
20	1					32
			STATCAP	1	29	33
129	1					34
20	1					35
			STATCAP	1	13	36
75	1					37
20	1					38
30	1					39
11	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

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20	1					1
9	1					2
20	1					3
25	1					4
11	1					5
8	1					6
			STATCAP	1	10	7
84	1					8
13	1					9
448	2					10
40	2					11
11	1					12
130	1					13
9	1					14
75	1					15
10	2					16
11	1					17
11	2					18
22	1					19
9	1					20
9	1					21
			STATCAP	1	14	22
22	1					23
8	1					24
			STATCAP	1	41	25
40	2					26
90	1					27
20	1					28
9	1					29
20	2					30
20	1					31
11	1					32
			STATCAP	1	11	33
6	2					34
20	1					35
2250	3	1				36
			REACTOR	3	100	37
900	2					38
13	2					39
11	1					40

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Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

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11	1					1
5	1					2
			STATCAP	1	16	3
50	1					4
56	1					5
37	1					6
			STATCAP	1	14	7
22	1					8
11	1					9
9	1					10
14	2					11
			STATCAP	1	16	12
50	1					13
			STATCAP	1	29	14
25	1					15
450	1					16
450	1					17
150		1				18
60	1					19
			STATCAP	1	72	20
90	1					21
			STATCAP	1	14	22
11	1					23
			STATCAP	1	14	24
25	1					25
7	2					26
20	1					27
			STATCAP	1	20	28
20	1					29
55	2					30
25	1					31
5	1					32
9	1					33
9	1					34
			STATCAP	1	4	35
11	1					36
20	1					37
11	1					38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
84	1					1
25		1				2
20	1					3
			STATCAP	1	22	4
50	1					5
50	1					6
			STATCAP	1		7
42	2					8
20	1					9
22	1					10
9	1					11
7	1					12
19	2					13
25	1					14
6	1					15
22	1					16
11	1					17
11	1					18
18	2					19
			STATCAP	1	14	20
75	1					21
9	1					22
			STATCAP	1	14	23
8	3	1				24
5		1				25
7	1					26
			STATCAP	1	14	27
450	1					28
20	1					29
130	1					30
			STATCAP	1	20	31
130	1					32
			STATCAP	1	43	33
6	1					34
			STATCAP	1	13	35
20	1					36
			REACTOR	3	300	37
			STATCAP	2	115	38
130	1					39
1		1				40

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Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

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20	1					1
25	1					2
22	1					3
20	1					4
6	1					5
75	1					6
35	1					7
	1					8
10	6	2				9
13	1					10
			STATCAP	1	14	11
			REACTOR	3	300	12
56	1					13
22	1					14
84	1					15
9	1					16
129	1					17
25	1					18
3	1					19
20	1					20
11	1					21
90	1					22
90	1					23
			STATCAP	2	115	24
9	1					25
			STATCAP	1	12	26
11	1					27
11	1					28
15	2					29
			STATCAP	1	18	30
75	1					31
			STATCAP	1	121	32
900	2					33
1500	3					34
			REACTOR	6	600	35
60	2					36
			STATCAP	1	14	37
22	1					38
19	3					39
			STATCAP	1	27	40

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SUBSTATIONS (Continued)

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25	1					1
22	1					2
15	2					3
15	2					4
22	1					5
11	1					6
			STATCAP	1	14	7
11	1					8
			STATCAP	1	10	9
20	1					10
22	1					11
56	1					12
13	1					13
5	1					14
11	1					15
20	1					16
			REACTOR	9	900	17
750		3				18
3000	3					19
20	1					20
14	2					21
33	2					22
25	1					23
22	1					24
20	1					25
11	1					26
75	1					27
33	3					28
			STATCAP	1	53	29
5		1				30
20	1					31
20	1					32
11	1					33
20	1					34
11	1					35
9	2					36
150	1					37
450	1					38
84	1					39
20	1					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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20	1					1
			STATCAP	1	14	2
90	1					3
60	2					4
20	1					5
			STATCAP	1	43	6
			STATCAP	1	10	7
40	2					8
			STATCAP	1	14	9
14	2					10
			STATCAP	1	14	11
128	1					12
56	1					13
39	1					14
			STATCAP	1	14	15
20	1					16
			STATCAP	1	7	17
56	1					18
			STATCAP	1	11	19
9	1					20
9	1					21
22	1					22
			STATCAP	1	10	23
39	1					24
22	1					25
			STATCAP	1	18	26
15	1					27
90	1					28
			STATCAP	1	18	29
16	2					30
84	1					31
90	1					32
			STATCAP	1	43	33
			STATCAP	2	31	34
20	1					35
20	1					36
16	2					37
20	1					38
11	1					39
50	1					40

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SUBSTATIONS (Continued)

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80	2					1
25	1					2
			STATCAP	1	58	3
11		1				4
3	1					5
			STATCAP	1	12	6
40	1					7
600	3					8
20	1					9
29	2					10
40	1					11
7	1					12
11	1					13
			STATCAP	1	13	14
20	1					15
			STATCAP	1	13	16
50	1					17
			STATCAP	1	5	18
11	1					19
47	2					20
56	1					21
			STATCAP	1	10	22
30	1					23
20	1					24
11	1					25
11	1					26
20	1					27
22	1					28
448	1					29
90		1				30
112	2					31
20		1				32
20		1				33
50		1				34
3		1				35
3		1				36
3		1				37
20	1					38
20	1					39
			STATCAP	1	14	40

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SUBSTATIONS (Continued)

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10	1					1
5	1					2
			STATCAP	1	10	3
21	2					4
11	2					5
9	1					6
25	1					7
			STATCAP	1	11	8
9	1					9
20	1					10
20	1					11
22	1					12
9	1					13
11	1					14
60	1					15
22	1					16
22	1					17
6	1					18
			STATCAP	1	14	19
10	6					20
50	1					21
50	6					22
20	1					23
			STATCAP	1	14	24
20	1					25
9	1					26
20	1					27
22	1					28
80	2					29
22	1					30
39	1					31
20	1					32
6	1					33
			STATCAP	1	10	34
22	1					35
16	2					36
11	1					37
25	1					38
84	1					39
			STATCAP	1	19	40

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SUBSTATIONS (Continued)

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75	1					1
22	1					2
13	1					3
50	1					4
15	1					5
13	1					6
150	1					7
75	1					8
5	1					9
			STATCAP	1	10	10
50	2					11
39	1					12
			STATCAP	1	14	13
1350	2					14
2250	3	1				15
75	1					16
30	1					17
20	1					18
39	1					19
3		1				20
84	1					21
8		1				22
11	1					23
40	2					24
			STATCAP	1	12	25
20	1					26
75	1					27
			STATCAP	1	18	28
30	2					29
			STATCAP	1		30
130	1					31
60	1					32
11	1					33
22	1					34
25	1					35
			STATCAP	1	6	36
40	2					37
						38
						39
						40

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SUBSTATIONS (Continued)

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129	1					1
70	4					2
			STATCAP	1	67	3
9	1					4
20	1					5
5	1					6
50	1					7
60	1					8
22	1					9
5	1					10
			STATCAP	1	10	11
672	1					12
11	1					13
450	1					14
450	1					15
448	1					16
			STATCAP	1	58	17
19	2					18
9	1					19
11	1					20
			STATCAP	1	10	21
20	1					22
			STATCAP	1	13	23
30	3					24
33	3	1				25
			STATCAP	1	14	26
112	1					27
20	1					28
5	1					29
20	1					30
30	1					31
22	1					32
84	1					33
20	1					34
42	1					35
30	3					36
20	1					37
			STATCAP	1		38
			STATCAP	1	14	39
22	1					40

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SUBSTATIONS (Continued)

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15	1					1
40	2					2
20	1					3
6	3					4
6	3					5
20	1					6
8		1				7
			STATCAP	1	86	8
150	1					9
450	1					10
60	1					11
3	2					12
130	1					13
4	1					14
50	1					15
9	1					16
6	1					17
90	1					18
11	1					19
			STATCAP	1	19	20
335	4					21
11	2					22
20	1					23
90	1					24
92	6	1				25
			STATCAP	1		26
11	1					27
			STATCAP	1	10	28
1		1				29
20	1					30
20	1					31
			STATCAP	1	14	32
25	1					33
22	1					34
6	1					35
			STATCAP	1	16	36
130	1					37
84	1					38
30	1					39
			STATCAP	1	53	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
11	1					1
130	1					2
22	1					3
400	1					4
115	1					5
90	1					6
30	1					7
			STATCAP	1	43	8
130	1					9
20	1					10
22	1					11
			STATCAP	1	62	12
25	1					13
			STATCAP	1	10	14
56	1					15
90	1					16
75	1					17
			STATCAP	1	58	18
6	1					19
4	1					20
			STATCAP	1	22	21
11	1					22
			STATCAP	1	14	23
129	1					24
25	1					25
			STATCAP	2	5	26
11	1					27
197	2					28
			STATCAP	1	72	29
			STATCAP	1	14	30
265	2					31
			STATCAP	1	46	32
20	1					33
20	2					34
			STATCAP	1	10	35
22	1					36
90	1					37
25	1					38
900	2					39
130		1				40

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
200	1					1
20	1					2
30	1					3
			STATCAP	1	53	4
			STATCAP	1	13	5
129	1					6
15	1					7
31	2					8
			STATCAP	1	72	9
11	1					10
20	1					11
25	1					12
22	1					13
			STATCAP	1	14	14
20	1					15
20	1					16
11	1					17
20	1					18
50	1					19
25	1					20
20	1					21
			STATCAP	2	50	22
130	1					23
25	1					24
			STATCAP	1	58	25
						26
1032	204					27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
56	1					2
			STATCAP	1	14	3
56	1					4
20	1					5
			STATCAP	1	14	6
			STATCAP	1	4	7
20	1					8
168	2					9
			STATCAP	4	14	10
1010	2	1				11
100	2					12
56	1					13
30		1				14
50	1					15
			STATCAP	2	7	16
40	2					17
50	1					18
	3					19
			STATCAP	1	7	20
9	1					21
11	1					22
			STATCAP	1		23
50	1					24
167	2	1				25
			STATCAP	1	72	26
			STATCAP	5	36	27
83	2					28
42		1				29
84	1					30
			STATCAP	1	11	31
			STATCAP	2	13	32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
675	1					1
675	1					2
42	1	1				3
158	2					4
25		2				5
7		2				6
22		1				7
9		3				8
9		1				9
33		1				10
9		1				11
9		1				12
9		1				13
			STATCAP	2	6	14
50	1					15
			STATCAP	1	5	16
			STATCAP	1	4	17
100	2					18
25	1					19
42	2					20
			STATCAP	1	3	21
100	2					22
50		1				23
20	1					24
20	1					25
2	1					26
252	3					27
			STATCAP	4	22	28
			STATCAP	4	31	29
50	1					30
60	2					31
30	1					32
			STATCAP	1	48	33
			STATCAP	1	12	34
			STATCAP	3	10	35
	1					36
56	2					37
			STATCAP	1		38
168	2					39
15	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
675	1					1
11		1				2
			STATCAP	2	173	3
11	1					4
11	1					5
			STATCAP	1		6
20	1					7
675	1					8
560	1					9
50	1	1				10
			STATCAP	1	115	11
45	2					12
92	2	1				13
			STATCAP	2	14	14
11	1					15
34	1					16
5		1				17
130	1					18
25	1					19
50	1					20
25	1					21
42	1					22
			STATCAP	1	18	23
			STATCAP	1	6	24
			STATCAP	2	11	25
150	3					26
			STATCAP	3	14	27
22	1					28
1		1				29
83	2					30
42		1				31
			STATCAP	1	72	32
			STATCAP	1	22	33
			STATCAP	4	12	34
22	1					35
75	1					36
63	3					37
			STATCAP	2	10	38
42	1					39
			STATCAP	1	3	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
50	1					1
53	2					2
50	1					3
			STATCAP	2	6	4
62	3					5
			STATCAP	3	10	6
252	3					7
			STATCAP	6	38	8
90	1					9
130	1					10
92	2					11
			STATCAP	2		12
			STATCAP	2		13
75	1					14
50	1					15
168	2	1				16
			STATCAP	1		17
			STATCAP	1	11	18
22		2				19
			STATCAP	5	17	20
92	2					21
			STATCAP	2	14	22
25	1					23
			STATCAP	1	4	24
11	2					25
20	1					26
56	1					27
167	4					28
			STATCAP	1	62	29
			STATCAP	2	13	30
45	2					31
			STATCAP	1	13	32
			STATCAP	2	5	33
70	3					34
			STATCAP	1	10	35
			STATCAP	2	7	36
						37
						38
						39
						40

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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84	1					1
83	2					2
			STATCAP	1	53	3
64	2					4
			STATCAP	4	14	5
600	2					6
50	1					7
11	1					8
21	2					9
			STATCAP	1	3	10
450	1					11
50	1					12
251	3					13
			STATCAP	5	25	14
			STATCAP	1	4	15
168	2					16
			STATCAP	2	10	17
40	2					18
560	1					19
90	1					20
42	1					21
			STATCAP	1	4	22
20	1					23
45	2					24
			STATCAP	1	4	25
11	1					26
			STATCAP	1	3	27
90	3					28
			STATCAP	1	43	29
			STATCAP	1	18	30
5		1				31
			STATCAP	2	7	32
60	2					33
42	1					34
42	1					35
			STATCAP	2	7	36
44	2					37
20	1					38
			STATCAP	1	7	39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

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50		1				1
50	1					2
			STATCAP	1	7	3
750	3	1				4
83	1					5
167	2					6
			STATCAP	1	53	7
13		1				8
17	6					9
			STATCAP	5	20	10
100	2					11
			STATCAP	1	86	12
			STATCAP	2	7	13
9	1					14
11	1					15
			STATCAP	2	10	16
			STATCAP	1	6	17
150	3					18
			STATCAP	2	3	19
40	2					20
50	2					21
242	3					22
			STATCAP	1	72	23
			STATCAP	6	43	24
168	2					25
			STATCAP	2	7	26
50	1					27
			STATCAP	1	7	28
34	1					29
			STATCAP	1	3	30
40	2					31
			STATCAP	2	6	32
6	1					33
6	1					34
100	2					35
			STATCAP	2	14	36
14	1					37
						38
						39
						40

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94	2					1
			STATCAP	1	50	2
11	1	1				3
11		1				4
6		1				5
38	2					6
13	1					7
20	1					8
10	1					9
			STATCAP	1	3	10
34	2					11
			STATCAP	1	3	12
45	2					13
			STATCAP	1	36	14
675	1					15
560	1					16
84	2					17
			REACTOR		40	18
			STATCAP	1	4	19
116	3					20
13		1				21
			STATCAP	1	65	22
2		1				23
			STATCAP	1	14	24
			STATCAP	3	11	25
20	1					26
42		1				27
177	2	1				28
			STATCAP	1	72	29
11	1					30
			STATCAP	1	3	31
90	1					32
149	2					33
25	1					34
			STATCAP	1	86	35
30	1					36
20	1					37
						38
						39
						40

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SUBSTATIONS (Continued)

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90	1					1
6		1				2
20	1					3
			STATCAP	1	29	4
92	2					5
			STATCAP	2	13	6
11	1					7
30	1					8
84	1					9
18	2					10
47	1					11
129	1					12
83	2					13
			STATCAP	2	14	14
47	1					15
11		1				16
20	1					17
92	2					18
93	1					19
			STATCAP	1	86	20
			STATCAP	5	29	21
30	1					22
30	1					23
			STATCAP	1	58	24
			STATCAP	2	5	25
			STATCAP	1	4	26
6		1				27
28	1					28
45	2					29
50	1					30
11	1					31
83	2	1				32
75	1					33
			STATCAP	1	72	34
			STATCAP	1	11	35
			STATCAP	2	7	36
187	1					37
20	1					38
20	1					39
						40

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SUBSTATIONS (Continued)

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50	1					1
			STATCAP	1	7	2
						3
						4
156	27					5
						6
						7
						8
504	1					9
						10
250	1					11
1920	3					12
640	1					13
900		1				14
						15
						16
						17
						18
						19
						20
1955	2					21
910	1					22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent Ohio Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2012/Q4

FOOTNOTE DATA

Schedule Page: 426.14 Line No.: 1 Column: a

On December 31, 2011, AEP affiliates Columbus Southern Power Company and Ohio Power Company were merged into one company, Ohio Power Company.

Schedule Page: 426.22 Line No.: 7 Column: a

SUBSTATION NOTES:
- For Commonly Owned Substations as noted:
- Applies to page 426.22 lines 7 - 27

Equipment at these substations is co-owned with The Duke Energy, The Dayton Power and Light Company (DP&L), and the Respondent (OPCO). Expenses are shared on the basis of ownership which may vary by commonly owned substation. The co-owners are not associated companies. The percent of ownership at the substations referenced by the footnotes are:

Company	Duke Energy	DP&L	OPCO
Footnote:			
(A)	33-1/3%	33-1/3%	33-1/3%
(B)	30%	35%	35%
(C)	28%	36%	36%
(D)	40.3%	30.7%	29%
(E)	38.5%	41.3%	20.2%

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
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Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Administrative and General Expenses - Maintenance	AEPSC	935	446,023
3	Administrative and General Expenses - Operation	AEPSC	Various (1)	22,037,763
4	Administrative and General Expenses - Operation	PSO	920-922, 930.1	713,500
5	Administrative and General Expenses - Operation	SWEPCO	920-922, 926	1,137,079
6	Administrative and General Expenses - Operation	TCC	920-922, 924-926	724,293
7	Assets & Other Debits - Current & Accrued Assets	APCO	152, 154, 163	570,740
8	Assets & Other Debits - Deferred Debits	AEP Pro Serv, Inc.	186	271,748
9	Assets & Other Debits - Deferred Debits	APCO	183 - 186, 188	706,413
10	Assets & Other Debits - Deferred Debits	I&M	184, 186, 188	2,900,041
11	Assets & Other Debits - Deferred Debits	KPCO	184, 186, 188	700,819
12	Assets & Other Debits - Deferred Debits	PSO	184, 186, 188	2,525,260
13	Assets & Other Debits - Deferred Debits	SWEPCO	184 - 186, 188	3,248,189
14	Assets & Other Debits - Deferred Debits	TCC	184, 186, 188	2,493,831
15	Assets & Other Debits - Deferred Debits	TNC	184, 186, 188	983,597
16	Assets & Other Debits - Deferred Debits	WPCO	184 - 186, 188	265,846
17	Assets & Other Debits - Utility Plant	I&M	107, 108	278,246
18	Assets & Other Debits - Utility Plant	KPCO	107, 108	718,567
19	Assets & Other Debits - Utility Plant	PSO	107, 108	318,016
20	**Non-power Goods or Services Provided for Affiliate**			
21	Administrative and General Expenses - Operation	I&M	Various (16)	654,325
22	Assets and Other Debits - Utility Plant	APCO	107, 108	392,920
23	Assets and Other Debits - Utility Plant	I&M	107, 108	440,121
24	Assets and Other Debits - Utility Plant	KPCO	107, 108	333,427
25	Assets and Other Debits - Utility Plant	OHTCO	107, 108	19,950,837
26	Assets and Other Debits - Utility Plant	WPCO	107, 108	2,249,790
27	Coal Transloading	APCO	456	941,920
28	Coal Transloading	I&M	456	32,639,336
29	Distribution Expenses - Maintenance	APCO	592 - 598	959,265
30	Distribution Expenses - Maintenance	KPCO	592 - 595, 597, 598	359,885
31	Distribution Expenses - Maintenance	WPCO	591 - 598	402,897
32	Distribution Expenses - Operation	WPCO	Various (17)	735,174
33	Emission Allowance Sales	I&M	158.1, 411.8, 411.9	4,276,097
34	Emission Allowance Sales	KPCO	158.1, 411.8, 411.9	5,033,939
35	Fleet and Vehicle Charges	APCO	Various (4)	2,195,093
36	Materials and Supplies	APCO	Various (18)	4,226,673
37	Materials and Supplies	I&M	Various (19)	1,716,412
38	Materials and Supplies	KPCO	Various (20)	590,626
39	Materials and Supplies	PSO	Various (21)	354,297
40	Materials and Supplies	TCC	Various (22)	261,160
41	Materials and Supplies	WPCO	Various (23)	327,128
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Assets & Other Debits - Utility Plant	SWEPCO	107, 108	374,326

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3	Assets & Other Debits - Utility Plant	WPCO	107, 108	250,280
4	Audit Services	AEPSC	920	2,481,190
5	Barging	I&M	151	37,111,608
6	Central Machine Shop	APCO	Various (2)	3,302,589
7	Civil & Political Activities and Other Svcs	AEPSC	426.1, 426.3-426.5	3,375,390
8	Construction Services	AEPSC	107, 108	66,454,666
9	Corporate Accounting	AEPSC	920	6,668,851
10	Corporate Communications	AEPSC	920	2,549,709
11	Corporate Planning & Budgeting	AEPSC	920	2,885,598
12	Customer Accounts Expenses	AEPSC	901-905	36,457,812
13	Customer and Distribution Services	AEPSC	920	984,446
14	Customer Service and Informational Expenses	AEPSC	907, 908, 910	1,023,180
15	Distribution Expenses - Maintenance	AEPSC	590-595, 597	3,001,942
16	Distribution Expenses - Maintenance	PSO	593	903,144
17	Distribution Expenses - Maintenance	SWEPCO	592-595, 597	897,440
18	Distribution Expenses - Maintenance	TCC	592-596	691,730
19	Distribution Expenses - Operation	AEPSC	Various (3)	11,300,572
20	**Non-power Goods or Services Provided for Affiliate**			
21	Other Operating Revenues	APCO	454, 456	763,919
22	Power Prod Exp - Steam Power Gen - Operation	APCO	500-502, 506	952,209
23	Rail Car Lease	APCO	151	1,960,157
24	Rail Car Lease	I&M	151	889,391
25	Rail Car Lease	SWEPCO	151	320,787
26	Rail Car Maintenance	I&M	417	3,342,737
27	Rail Car Maintenance	PSO	417	281,483
28	Rail Car Maintanance	SWEPCO	417	2,101,850
29	Transmission Expenses - Maintenance	WPCO	568-571	396,406
30	Urea	APCO	154, 186	11,012,376
31	Urea	KPCO	154, 186	1,163,029
32	Use of Jointly Owned Facilities	OHTCO	456	267,126
33	Administrative and General Expenses - Operation	AEP T&D Services, LLC	920, 930.2	525,467
34	Assets and Other Debits - Utility Plant	Cardinal Operating Co	107, 108	486,593
35	Building and Property Leases	AEPSC	454	11,195,333
36	Fleet and Vehicle Charges	AEPSC	Various (4)	1,721,759
37	Power Prod Exp - Steam Power Gen - Maintenance	Cardinal Operating Co	510 - 514	634,135
38	Power Prod Exp - Steam Power Gen - Operation	Cardinal Operating Co	500, 501, 505, 506	891,196
39	Urea	Cardinal Operating Co	154, 186	465,074
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Emission Allowance Purchases	APCO	158.1, 411.9	2,198,790
3	Enviro Safety Health Facilities	AEPSC	920	3,751,388
4	Ethics & Compliance	AEPSC	920	256,127

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Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
5	Factored Customer A/R Bad Debts	AEP Credit	426.5	14,135,551
6	Factored Customer A/R Expense	AEP Credit	426.5	6,176,052
7	Finance, Acctg. & Strategic Plng Admin	AEPSC	920	666,930
8	Fleet and Vehicle Charges	APCO	Various (4)	2,749,170
9	Fuel & Storeroom Services	AEPSC	151, 152, 163	8,224,371
10	Gypsum Storage	APCO	456	307,497
11	Human Resources	AEPSC	923	4,654,577
12	Information Technology	AEPSC	923	13,349,123
13	Leased Transmission Lines	WPCO	565	1,351,836
14	Legal GC/Administration	AEPSC	920	5,934,823
15	Liabilities and Other Credits - Deferred Credits	I&M	253	362,698
16	Materials and Supplies	APCO	Various (5)	2,113,817
17	Materials and Supplies	I&M	Various (6)	808,441
18	Materials and Supplies	KPCO	Various (7)	2,488,885
19	Materials and Supplies	OHTCO	107, 108, 930	3,964,575
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Materials and Supplies	PSO	Various (8)	456,517
3	Materials and Supplies	SWEPCO	Various (9)	373,938
4	Materials and Supplies	WPCO	Various (10)	2,073,993
5	O&M Services for Jointly Owned Facility - Amos	APCO	Various (11)	40,342,953
6	O&M Services for Jointly Owned Facility - Sporn	APCO	Various (12)	13,137,758

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

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Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
7	Other Power Generation - Maintenance	AEPSC	553, 555 - 557	12,860,965
8	Other Power Generation - Operation	AEPSC	546 - 549	408,478
9	Power Prod Exp - Steam Power Gen - Maintenance	APCO	510 - 514	434,721
10	Rail Car Lease	APCO	186	853,594
11	Real Estate & Workplace Svcs	AEPSC	923	2,036,783
12	Regulatory Services	AEPSC	920	3,987,260
13	Relative Accuracy Test Audits	USTI	500	405,362
14	Research and Other Services	AEPSC	Various (13)	7,542,042
15	Risk and Strategic Initiatives	AEPSC	920	1,802,643
16	Simulator Learning Center	APCO	506	563,123
17	Steam Power Generation - Maintenance	AEPSC	510 - 514	11,168,641
18	Steam Power Generation - Operation	AEPSC	500 - 502, 505, 506	21,432,967
19	Supply Chain & Fleet Operations	AEPSC	923	579,485
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Transmission Expenses - Maintenance	AEPSC	Various (14)	1,929,103
3	Transmission Expenses - Operation	AEPSC	Various (15)	12,809,842
4	Treasury & Investor Relations	AEPSC	920	1,238,869
5	Urea	Cardinal Operating Co	154, 186	534,623
6	Utility Operations	AEPSC	920	2,331,670
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8				

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Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
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20	**Non-power Goods or Services Provided for Affiliate**			
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FOOTNOTE DATA

Schedule Page: 429 Line No.: 2 Column: b

Certain managerial and professional services provided by AEPSC are allocated among multiple affiliates. The costs of the services are billed on a direct-charge basis, whenever possible. Costs incurred to perform services that benefit more than one company are allocated to the benefiting companies using one of 80 FERC accepted allocation factors. The allocation factors used to bill for services performed by AEPSC are based upon formulae that consider factors such as number of customers, number of employees, number of transmission pole miles, number of invoices and other factors. The data upon which these formulae are based is updated monthly, quarterly, semi-annually or annually, depending on the particular factor and its volatility. The billings for services are made at cost and include no compensation for a return on investment.

Schedule Page: 429 Line No.: 3 Column: c

Various Account Listings as provided in Column (c):

Various (1) - 920, 921, 923-926, 928, 930.1, 930.2, 931

Various (2) - 107, 506, 512-514, 544

Various (3) - 580-584, 586, 588, 589

Various (4) - Cost related to AEP's fleet vehicles are allocated in the same manner as the labor of each department utilizing the vehicles. To the extent a department provides service to another affiliate company, an applicable share of their fleet costs are also assigned to that affiliate company.

Various (5) - 107, 108, 154, 163, 184, 186, 506, 511-514, 539, 553, 562, 569-571, 573, 580, 583, 586, 588, 592-596, 903, 930, 935

Various (6) - 107, 108, 154, 186, 506, 512-514, 531, 539, 562, 566, 570, 571, 588, 597, 903, 930, 935

Various (7) - 107, 154, 163, 511-513, 562, 566, 570, 571, 583, 585, 586, 588, 592-595, 902, 903, 935

Various (8) - 107, 154, 163, 512, 513, 930, 935

Various (9) - 107, 108, 154, 163, 512, 513, 593

Various (10) - 107, 108, 154, 163, 186, 570, 571, 583, 586, 592-594, 935

Various (11) - 152, 408.1, 421, 426.1, 426.3-426.5, 431, 500-502, 505-507, 510-514, 556, 557, 920, 921, 923-926, 930.1, 930.2, 931, 935

Various (12) - 152, 408.1, 421, 426.1, 426.3-426.5, 431, 500-502, 505-507, 510-514, 920, 921, 923-926, 928, 930.1, 930.2, 931, 935

Various (13) - 182.3, 183, 184, 186, 188

Various (14) - 568, 569, 569.1-569.3, 570-573

Various (15) - 560, 561.1-561.3, 561.5, 562, 563, 566, 567

Various (16) - 920-923, 930.1, 930.2, 931

Various (17) - 580, 582, 583, 586, 588, 589

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) X An Original (2) _ A Resubmission	/ /	2012/Q4

FOOTNOTE DATA

Various (18) - 107, 108, 154, 163, 186, 502, 506, 511-514, 562, 570, 571, 586, 588, 592-594, 597, 902, 930, 935

Various (19) - 107, 108, 154, 163, 186, 506, 511, 512, 562, 570, 571, 592-595, 902, 921, 935

Various (20) - 107, 154, 163, 186, 511-513, 570, 571, 583, 588, 592, 935

Various (21) - 107, 154, 163, 186, 512-514, 593

Various (22) - 107, 154, 163, 186, 571, 592, 594

Various (23) - 107, 154, 186, 506, 511, 513, 570, 588, 592

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