AMERICAN ELECTRIC POWER CO INC
Form 10-K
February 26, 2013

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

FORM 10-K

(Mark One)

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

o 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) 1 Riverside Plaza, Columbus, Ohio 43215 Telephone (614) 716-1000	72-0323455

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 T	No o
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 o	No T
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 o	No T
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 T	No o
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 T	No o
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.	T	

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	T	Accelerated filer	o
Non-accelerated filer	o (Do not check if a smaller reporting company)	Smaller reporting company	o

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	o	Accelerated filer	o
Non-accelerated filer	T (Do not check if a smaller reporting company)	Smaller reporting company	o

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

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:	Part II
American Electric Power Company, Inc.	
Appalachian Power Company	
Indiana Michigan Power Company	
Ohio Power Company	
Public Service Company of Oklahoma	
Southwestern Electric Power Company	
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.

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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.
CO2	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.
NOx	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.
SO2	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,” “v “should,” “could,” “would,” “project,” “continue” and similar expressions, and include statements reflecting future results 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.

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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 SO2 emissions from power plants. By 2000, the program established a nationwide cap on power plant SO2 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 NOx emissions through the use of available combustion controls.

The success of the SO2 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 SO2 and NOx 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 SO2 in 2010, a lower standard for NOx 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 SO2 and NOx 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 SO2 and NOx 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

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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.

CO2 Regulation

In the absence of comprehensive climate change legislation, the Federal EPA has taken action to regulate CO2 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 CO2 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 CO2 emissions. If substantial CO2 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 CO2 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 CO2 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 CO2 and other greenhouse gases (generally referred to as CO2) that recognizes that a reliable and affordable electricity supply is vital to economic recovery and growth. We do not believe regulating CO2 emissions under the Clean Air Act is the appropriate solution. During the past decade, we have taken voluntary actions to reduce and offset our CO2 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 CO2 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 CO2 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 CO2 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 CO2 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 CO2 Emission

Our total CO2 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 CO2 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 CO2 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 (MWs)	Member-Load Ratio (%)
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 SO2 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)

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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.

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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.

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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 CO2 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 CO2 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 CO2 emission standards for new motor vehicles, and issued a rule that implements a permitting program for new and modified stationary sources of CO2 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 CO2 emissions standard for new power generation sources with a CO2 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.

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2. FINANCIAL STATEMENT SCHEDULES:	Number
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

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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

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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

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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		
(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 (in millions)	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 (in millions)	2017	After 2017	Total
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 (in millions)	Weighted Average Interest Rate		Outstanding Amount (in millions)	Weighted Average Interest Rate
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	Additions: 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	Balance at End of Period

Description				Accounts (a) (in thousands)	Deductions (b)	
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

		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a) (in thousands)	Deductions (b)	Balance at End of Period
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)		2011 Form 10-K, Ex 10(r)(1)(A)

	First Amendment to Nuclear Key Contributor Retention Plan Amended and Restated as of January 1, 2008.	
*†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.	
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101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

Exhibit Designation APCo‡ File No. 1-3457	Nature of Exhibit	Previously Filed as Exhibit to:
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.	
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
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*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
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I&M‡ File No. 1-3570

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	Registration Statement No. 2-52910, Ex 5(a) Registration Statement No. 2-61009, Ex 5(b)

	amended.	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.	
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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

E-8

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)		Form 8-K, Ex 4.1 dated January 6, 2012

	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.	
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,	2004 Form 10-K, Ex 10(d)(3)

	KGPCo and WPCo.	
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.	
*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.	
*95	Mine Safety Disclosure.	
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.	

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.	
*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.

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.
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
*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.	
*95	Mine Safety Disclosure.	
101.INS	XBRL Instance Document.	
101.SCH	XBRL Taxonomy Extension Schema.	
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101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	

‡ 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.