

AMERICAN ELECTRIC POWER CO INC
 Form 10-K
 February 20, 2015

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

FORM 10-K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2014

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	

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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 of the Securities Act. Yes No

Indicate by check mark if the registrants Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company, are well-known seasoned issuers, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes No

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether American Electric Power Company, Inc., Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company have submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (229.405 of this chapter) is not contained herein and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

Large accelerated filer Accelerated filer

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

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

Large accelerated filer Accelerated filer

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

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

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

	Aggregate Market Value of Voting and Non-Voting Common Equity Held by Non-Affiliates of the Registrants as of June 30, 2014 the Last Trading Date of the Registrants' Most Recently Completed Second Fiscal Quarter	Number of Shares of Common Stock Outstanding of the Registrants as of December 31, 2014
American Electric Power Company, Inc.	\$27,293,981,162	489,402,567 (\$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, 2014: American Electric Power Company, Inc. Appalachian Power Company Indiana Michigan Power Company Ohio Power Company Public Service Company of Oklahoma Southwestern Electric Power Company	Part II
Portions of Proxy Statement of American Electric Power Company, Inc. for 2015 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 electric system, owned and operated by AEP subsidiaries.
AEP Utilities	AEP Utilities, Inc., a subsidiary of AEP, and a holding company for TCC, TNC and our interest in ETT.
AEP West Companies	PSO, SWEPCo, TCC and TNC.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a subsidiary of AEPTHCo, an intermediate holding company that owns seven wholly-owned transmission companies.
AEPTHCo	AEP Transmission Holding Company, LLC, a subsidiary of AEP, an intermediate holding company that owns our transmission operations joint ventures and AEPTCo.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a nonregulated AEP subsidiary in the Generation & Marketing segment.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
CAA	Clean Air Act.
CO ₂	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CRES provider	Competitive Retail Electric Service providers under Ohio law that target retail customers by offering alternative generation service.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
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 Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
I&M	AEP Indiana Michigan Power Company, Inc.
IMTCo	Indiana Michigan Transmission Company Inc.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo, which defined the sharing of costs and benefits associated with their respective generation plants. This agreement was terminated January 1, 2014.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.

KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
kV	Kilovolt.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.

Term	Meaning
MW	Megawatt.
NO _x	Nitrogen oxide.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NRC	Nuclear Regulatory Commission.
OATT	Open Access Transmission Tariff.
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 generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity for AEP and SWEPCo.
SEC	U.S. Securities and Exchange Commission.
SO ₂	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TA	Transmission Agreement, effective November 2010, among APCo, CSPCo, I&M, KGPCo, KPCo, OPCo and WPCo with AEPSC as agent.
TCA	Transmission Coordination Agreement dated January 1, 1997, by and among, PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two public utility subsidiaries.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

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

The economic climate, growth or contraction within and changes in market demand and demographic patterns in our service territory.

Inflationary or deflationary interest rate trends.

Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.

The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.

Electric load, customer growth and the impact of competition, including competition for retail customers.

Weather conditions, including storms and drought conditions, and our ability to recover significant storm restoration costs.

Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.

Availability of necessary generation capacity and the performance of our generation plants.

Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.

Our ability to build or acquire generation 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.

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, cost recovery and/or profitability of our generation 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 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, alternative or distributed sources of generation.

Our ability to recover through rates or market prices any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.
Volatility and changes in markets for capacity and electricity, coal and other energy-related commodities, particularly changes in the price of natural gas and capacity auction returns.

Changes in utility regulation and the allocation of costs within regional transmission organizations, including ERCOT, PJM and SPP.

The transition to market for generation in Ohio, including the implementation of ESPs and our ability to recover investments in our Ohio generation assets.

Our ability to successfully and profitably manage our separate competitive generation assets.

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 of such volatility 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 Material 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 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 laws in Michigan, Ohio and the ERCOT area of Texas have caused AEP public utility subsidiaries in those states to unbundle previously integrated regulated rates for their retail customers. In Ohio, AEP's regulated utility operates its distribution and transmission assets while its former generation assets are owned and operated by a competitive generation affiliate.

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, 2014, the subsidiaries of AEP had a total of 18,529 employees. Because it is a holding company rather than an operating company, AEP has no employees. The material subsidiaries of AEP are:

APCo

Organized in Virginia in 1926, APCo is engaged in the generation, transmission and distribution of electric power to approximately 959,000 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. APCo owns 7,877 MW of generating capacity. APCo uses its generation to serve its retail and other customers. As of December 31, 2014, APCo had 1,902 employees. Among the principal industries served by APCo are paper, rubber, coal mining, textile mill products and stone, clay and glass products. APCo is a member of PJM. APCo is part of AEP's Vertically Integrated Utilities segment.

I&M

Organized in Indiana in 1907, I&M is engaged in the generation, transmission and distribution of electric power to approximately 588,000 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. I&M owns or leases 4,518 MW of generating capacity, which it uses to serve its retail and other customers. As of December 31, 2014, I&M had 2,551 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. I&M is a member of PJM. I&M is part of AEP's Vertically Integrated Utilities segment.

KPCo

Organized in Kentucky in 1919, KPCo is engaged in the generation, transmission and distribution of electric power to approximately 171,000 retail customers in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. KPCo owns 1,858 MW of generating capacity. KPCo uses its generation to serve its retail and other customers. As of December 31, 2014, KPCo had 595 employees. Among the principal industries served are petroleum refining, coal mining and chemical production. KPCo is a member of PJM. KPCo is part of AEP's Vertically Integrated Utilities segment.

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, 2014, KGPCo had 49 employees. KGPCo is part of AEP's Vertically Integrated Utilities segment.

OPCo

Organized in Ohio in 1907 and re-incorporated in 1924, OPCo is engaged in the transmission and distribution of electric power to approximately 1,466,000 retail customers in Ohio. Following corporate separation of OPCo's generation assets in December 2013, OPCo purchases energy and capacity to serve generation service customers. As of December 31, 2014, OPCo had 1,516 employees. 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. OPCo is a member of PJM. OPCo is part of AEP's Transmission and Distribution Utilities segment.

PSO

Organized in Oklahoma in 1913, PSO is engaged in the generation, transmission and distribution of electric power to approximately 542,000 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. PSO owns 4,436 MW of generating capacity, which it uses to serve its retail and other customers. As of December 31, 2014, PSO had 1,133 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. PSO is a member of SPP. PSO is part of AEP's Vertically Integrated Utilities segment.

SWEPCo

Organized in Delaware in 1912, SWEPCo is engaged in the generation, transmission and distribution of electric power to approximately 528,000 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. SWEPCo owns 5,779 MW of generating capacity, which it uses to serve its retail and other customers. As of December 31, 2014, SWEPCo had 1,468 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. SWEPCo is a member of SPP. SWEPCo is part of AEP's Vertically Integrated Utilities segment.

TCC

Organized in Texas in 1945, TCC is engaged in the transmission and distribution of electric power to approximately 817,000 retail customers through REPs in southern Texas. As of December 31, 2014, TCC had 1,056 employees. Among the principal industries served by TCC are chemical and petroleum refining, chemicals and allied products, oil and natural gas extraction, food processing, metal refining, plastics and machinery equipment. TCC is a member of ERCOT. TCC is part of AEP's Transmission and Distribution Utilities segment.

TNC

Organized in Texas in 1927, TNC is engaged in the transmission and distribution of electric power to approximately 189,000 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, 2014, TNC had 323 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. TNC is a member of ERCOT. TNC is part of AEP's Transmission and Distribution Utilities segment.

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. As of December 31, 2014, WPCo did not own any generating facilities. On January 31, 2015, WPCo acquired an interest in a 780 MW generating unit owned by AGR. WPCo is a member of PJM. Prior to acquiring the 780 MW generating unit interest, WPCo purchased electric power from AGR for distribution to its customers. As of December 31, 2014, WPCo had 53 employees. WPCo is part of AEP's Vertically Integrated Utilities segment.

AEGCo

Organized in Ohio in 1982, AEGCo is an electric generating company. AEGCo owns 2,496 MW of generating capacity. AEGCo sells power at wholesale to AGR, I&M and KPCo. As of December 31, 2014, AEGCo had 70 employees. AEGCo is part of AEP's Vertically Integrated Utilities segment.

AGR

Organized in Delaware in 2011, AGR is a competitive generation company that generates power and sells it into the market. AGR also engages in power trading activities. Pursuant to a Power Supply Agreement (PSA) between AGR and OPCo, AGR supplies capacity for OPCo's switched and non-switched retail load for the period January 1, 2014 through May 31, 2015. AGR also supplied the energy needs of OPCo's non-switched retail load that was not acquired through auctions in 2014 under the PSA. Following the transfer to WPCo of the 780MW generating unit interest on January 31, 2015, AGR owns 9,159 MW of generating capacity, with rights to an additional 1,186 MW pursuant to a unit power agreement with AEGCo through 2017. As of December 31, 2014, AGR had 917 employees. AGR is part of AEP's Generation & Marketing segment.

AEPTHCo

Organized in Delaware in 2012, AEPTHCo is a holding company for AEP's transmission operations joint ventures. AEPTHCo also owns AEPTCo, a holding company for seven FERC-regulated transmission-only electric

utilities, each of which is geographically aligned with our existing utility operating companies. The transmission companies 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, Kentucky, Michigan, Ohio, Oklahoma and West Virginia, subject to any applicable siting requirements, and are authorized to submit projects for

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commission approval in Virginia. The application for regulatory approval to operate in Louisiana is under consideration, while the application for regulatory approval to operate in Arkansas was denied. Neither AEPTCo nor the transmission companies have any employees. Instead, AEPSC and certain of our utility subsidiaries provide the services required by these entities. AEPTCo is part of the AEP Transmission Holdco segment.

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, 2014, AEPSC had 5,569 employees.

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)	AEP Utility Subsidiaries Operating in that Jurisdiction	Authorized Return on Equity (b)
Ohio	25%	OPCo	10.20%
Texas	14%	TCC TNC SWEPCo	9.96% 9.96% 9.65%
Virginia	13%	APCo	9.70%
West Virginia	11%	APCo WPCo	10.00% 10.00%
Oklahoma	11%	PSO	10.15%
Indiana	10%	I&M	10.20%
Louisiana	5%	SWEPCo	10.00%
Kentucky	5%	KPCo	10.50%
Arkansas	3%	SWEPCo	10.25%
Michigan	2%	I&M	10.20%
Tennessee	1%	KGPCo	12.00%

(a) Represents the percentage of public utility subsidiaries revenue from sales to retail customers to total public utility subsidiaries revenue for the year ended December 31, 2014.

(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.

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 years ended December 31, 2014, 2013 and 2012 are as follows:

Description	Years Ended December 31,			
	2014	2013	2012	
	(in millions)			
Vertically Integrated Utilities Segment				
Retail Revenues				
Residential Sales	\$3,329	\$3,216	\$2,993	
Commercial Sales	2,032	2,002	1,886	
Industrial Sales	2,125	2,029	1,951	
PJM Net Charges	(62) 10	(25)
Provision for Rate Refund	(2) (16) (3)
Other Retail Sales	182	172	164	
Total Retail Revenues	7,604	7,413	6,966	
Wholesale Revenues				
Off-System Sales	1,530	1,671	1,583	
Transmission	113	133	103	
Total Wholesale Revenues	1,643	1,804	1,686	
Other Electric Revenues	125	90	98	
Other Operating Revenues	25	39	35	
Sales to Affiliates	87	646	633	
Total Revenues Vertically Integrated Utilities Segment	9,484	9,992	9,418	
Transmission and Distribution Utilities Segment				
Retail Revenues				
Residential Sales	2,313	2,164	2,121	
Commercial Sales	1,178	1,161	1,331	
Industrial Sales	503	549	821	
PJM Net Charges	48	21	22	
Provision for Rate Refund	(12) 22	(3)
Other Retail Sales	40	39	41	
Total Retail Revenues	4,070	3,956	4,333	
Wholesale Revenues				
Off-System Sales	143	31	57	
Transmission	278	228	205	
Total Wholesale Revenues	421	259	262	
Other Electric Revenues	51	56	58	
Other Operating Revenues	11	8	6	
Sales to Affiliates	261	199	159	
Total Revenues Transmission and Distribution Utilities Segment	4,814	4,478	4,818	
AEP Transmission Holdco Segment				
Transmission Revenues	74	27	7	
Sales to Affiliates	118	51	17	
Total Revenues AEP Transmission Holdco Segment	192	78	24	
Generation & Marketing Segment				

Generation Revenues			
Affiliated	1,307	2,457	2,584
Nonaffiliated	1,397	314	282
Trading, Marketing and Retail Revenues			
Affiliated	159	—	1
Nonaffiliated	962	868	572
Wind Generation Revenues			
Nonaffiliated	25	26	28
Total Revenues Generation & Marketing Segment	\$3,850	\$3,665	\$3,467

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APCo

Description	Years Ended December 31,		
	2014	2013	2012
	(in thousands)		
Retail Revenues			
Residential Sales	\$1,257,273	\$1,219,649	\$1,159,576
Commercial Sales	585,929	583,835	576,153
Industrial Sales	690,432	697,043	701,603
PJM Net Charges	13,447	4,998	(13,049)
Provision for Rate Refund	(6,085)) —	—
Other Retail Sales	82,484	77,182	72,455
Total Retail Revenues	2,623,480	2,582,707	2,496,738
Wholesale Revenues			
Off-System Sales	191,194	433,575	409,527
Transmission	26,898	21,049	14,059
Total Wholesale Revenues	218,092	454,624	423,586
Other Electric Revenues	57,830	22,246	28,438
Total Electric Generation, Transmission and Distribution Revenues	2,899,402	3,059,577	2,948,762
Sales to Affiliates	144,437	347,484	318,199
Other Revenues	9,239	10,345	9,970
Total Revenues	\$3,053,078	\$3,417,406	\$3,276,931

I&M

Description	Years Ended December 31,		
	2014	2013	2012
	(in thousands)		
Retail Revenues			
Residential Sales	\$588,445	\$565,822	\$505,142
Commercial Sales	390,439	400,810	377,302
Industrial Sales	462,982	455,067	430,042
PJM Net Charges	(60,912)) 3,318	(9,003)
Provision for Rate Refund	(592)) —	—
Other Retail Sales	6,895	6,945	6,508
Total Retail Revenues	1,387,257	1,431,962	1,309,991
Wholesale Revenues			
Off-System Sales	759,531	571,802	481,000
Transmission	(9,444)) 4,145	2,092
Total Wholesale Revenues	750,087	575,947	483,092
Other Electric Revenues	11,765	14,348	16,986
Total Electric Generation, Transmission and Distribution Revenues	2,149,109	2,022,257	1,810,069
Sales to Affiliates	98,577	341,686	385,460
Other Revenues	2,048	2,916	4,582
Total Revenues	\$2,249,734	\$2,366,859	\$2,200,111

OPCo

Description	Years Ended December 31,		
	2014	2013	2012

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(in thousands)

Retail Revenues			
Residential Sales	\$1,768,143	\$1,676,138	\$1,636,808
Commercial Sales	732,227	763,820	945,233
Industrial Sales	405,742	468,358	742,235
PJM Net Charges	47,532	6,916	(18,831)
Provision for Rate Refund	(11,937)	22,091	(2,577)
Other Retail Sales	14,887	15,881	18,113
Total Retail Revenues	2,956,594	2,953,204	3,320,981
Wholesale Revenues			
Off-System Sales	143,037	563,040	661,513
Transmission	78,510	17,699	10,114
Total Wholesale Revenues	221,547	580,739	671,627
Other Electric Revenues	26,785	28,281	29,508
Total Electric Generation, Transmission and Distribution Revenues	3,204,926	3,562,224	4,022,116
Sales to Affiliates	165,216	1,184,994	886,695
Other Revenues	6,778	15,397	19,385
Total Revenues	\$3,376,920	\$4,762,615	\$4,928,196

PSO			
Description	Years Ended December 31,		
	2014	2013	2012
	(in thousands)		
Retail Revenues			
Residential Sales	\$561,175	\$530,446	\$512,372
Commercial Sales	375,535	351,521	331,125
Industrial Sales	260,380	234,072	209,446
Other Retail Sales	78,666	73,649	70,894
Total Retail Revenues	1,275,756	1,189,688	1,123,837
Wholesale Revenues			
Off-System Sales	13,790	34,636	37,484
Transmission	36,540	36,393	30,669
Total Wholesale Revenues	50,330	71,029	68,153
Other Electric Revenues	14,221	16,994	14,593
Total Electric Generation, Transmission and Distribution Revenues	1,340,307	1,277,711	1,206,583
Sales to Affiliates	7,054	14,246	22,603
Other Revenues	4,215	3,565	3,752
Total Revenues	\$1,351,576	\$1,295,522	\$1,232,938
SWEPCo			
Description	Year Ended December 31,		
	2014	2013	2012
	(in thousands)		
Retail Revenues			
Residential Sales	\$580,367	\$586,517	\$512,578
Commercial Sales	457,217	472,264	404,204
Industrial Sales	348,901	316,282	298,604
Provision for Rate Refund	4,976	(16,110)	(1,207)
Other Retail Sales	8,341	8,360	8,074
Total Retail Revenues	1,399,802	1,367,313	1,222,253
Wholesale Revenues			
Off-System Sales	339,286	294,594	247,118
Transmission	55,095	59,097	48,404
Total Wholesale Revenues	394,381	353,691	295,522
Other Electric Revenues	23,680	21,571	20,758
Total Electric Generation, Transmission and Distribution Revenues	1,817,863	1,742,575	1,538,533
Sales to Affiliates	26,278	51,812	37,441
Other Revenues	2,256	1,416	1,860
Total Revenues	\$1,846,397	\$1,795,803	\$1,577,834

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 2014 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. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of our major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of \$50 million, would cause an event of default under these credit agreements. As of December 31, 2014, 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 2014 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 Water Act Requirements

Our operations are 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 2014, the Federal EPA issued a final rule setting forth standards for existing power plants that is intended to reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. The 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 standard for entrainment for existing facilities requires a site-specific evaluation of the available measures for reducing entrainment. Challenges to this final rule have been consolidated in the U.S. Court of Appeals for the Second Circuit, and additional changes could be made to this rule as a result of review by the court.

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 proposed revised standards in 2013. A final rule is expected in September 2015. For additional information, see Management's Discussion and Analysis of Financial Condition and Results of Operations under the headings entitled Environmental Issues.

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Coal Ash Regulation

Our operations produce a number of different coal combustion products, including fly ash, bottom ash, gypsum and other materials. 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 December 2014, the Federal EPA signed a rule to regulate the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at coal-fired electric generating units. The final rule requires certain standards for location, groundwater monitoring and dam stability to be met at landfills and certain surface impoundments at operating facilities on a schedule spanning approximately four years after publication of the final rule in the Federal Register. If existing disposal facilities cannot meet these standards, they will be required to close, but the time frame for closure may be extended if adequate alternative disposal options are not available. Extensions are available for completion of certain activities. 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.

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 NO_x 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 NO_x emission reduction requirements than the Acid Rain Program on many of our facilities. We have installed additional controls and taken other actions to achieve compliance with these programs.

National Ambient Air Quality Standards

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

Each state identifies the areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (nonattainment areas). Each state must develop a state implementation plan (SIP) to bring nonattainment areas into

compliance with the NAAQS and maintain good air quality in attainment areas. All SIPs are submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA develops and implements a plan. As the Federal EPA reviews the NAAQS and establishes new concentration levels, the attainment status of areas can change and states may be required to develop new SIPs. In 2008, the Federal EPA issued revised NAAQS for both ozone and fine particulate matter (PM_{2.5}). The PM_{2.5} standard was remanded by the D.C. Circuit Court of Appeals, and a new

rule was signed by the administrator in December 2012 that lowers the annual standard. A new ozone standard was proposed in 2014. The Federal EPA also adopted a new short-term standard for SO₂ in 2010, a lower standard for NO_x in 2010, and confirmed the existing standard for lead in 2014. The existing standard for carbon monoxide was retained in 2011. The states are in the process of developing new SIPs for the SO₂, NO_x and PM_{2.5} standards, which could result in more stringent emission limitations being imposed on our facilities. Additional designations of SO₂ nonattainment areas and finalization of a more stringent ozone standard could also lead to the imposition of more stringent emission limitations on our facilities.

In 2005, the Federal EPA issued the Clean Air Interstate Rule (CAIR), which requires additional reductions in SO₂ and NO_x emissions from power plants and assists states developing new SIPs to meet the NAAQS. In August 2011, the Federal EPA issued a final rule to replace CAIR (the Cross State Air Pollution Rule (CSAPR)) that contains more stringent requirements to control SO₂ and NO_x emissions from fossil fuel-fired electric generating units in 27 states and the District of Columbia. Petitions for review were filed with the U.S. Court of Appeals for the District of Columbia Circuit, and CSAPR was vacated. That decision was subsequently reversed by the U.S. Supreme Court and remanded back to the U.S. Court of Appeals for further proceedings. The Federal EPA filed a motion to lift the stay and allow Phase I of CSAPR to take effect on January 1, 2015 and Phase II to take effect on January 1, 2017. The court granted the Federal EPA's motion, an interim final rule has been issued, and further consideration of the petitions for review on CSAPR will continue during 2015 while Phase I is in effect. For additional information regarding CAIR and 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. Petitions for review of the MACT standards were denied by the U.S. Court of Appeals for the D.C. Circuit, but in 2014 the U.S. Supreme Court granted certiorari to determine whether Federal EPA should have considered costs in determining if it was appropriate and necessary to regulate hazardous air pollutant emissions from electric generating units. For additional information regarding 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 Oklahoma. Federal EPA is likely to issue a Federal Implementation Plan for Arkansas in 2015. 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.

Climate Change

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 CAA is the appropriate solution. In the past decade, we have taken voluntary actions to reduce and offset our CO₂ emissions, and have complied with state energy policies designed to reduce carbon emissions through increasing reliance on renewable resources and expanding our energy efficiency programs.

AEP's total CO₂ emissions in 2014 (not including our ownership in the Kyger Creek and Clifty Creek plants) were approximately 120 million metric tons. This represents a reduction of 18% compared to our 2005 CO₂ emission of approximately 146 million metric tons. We expect minor variations in CO₂ emissions in the near-term as potential sales and emission increases from rebounding economic activity to be offset by expected changes in generation sources.

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 includes diversifying our fuel portfolio and generating more electricity from natural gas, increasing energy efficiency and investing in renewable resources, where there is regulatory support.

In the absence of comprehensive climate change legislation, the Federal EPA has taken action to regulate CO₂ emissions under the existing provisions of the CAA. Such actions are being legally challenged by numerous parties and final regulatory outcomes remain uncertain. 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 – Climate Change, CQ Regulation and Energy Policy.

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 generation 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. For our sales of energy into the markets, however, there is no such recovery mechanism.

Renewable Sources of Energy

Some of the states we serve 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). During 2014 in support of our goals or requirements, our operating companies procured rights to an additional 199 MW of wind power and at the end of 2014 our operating companies had long-term contracts for 2,183 MW of wind and 10 MW of solar power. In addition, the Indiana Utility Regulatory Commission has approved I&M's proposal for a self-build Clean Energy Solar Pilot Project (15.7 MW). When the additional projects under construction and/or pending regulatory approval are added and netted against one wind contract that is expiring at the end of 2015, the total renewable portfolio will be 2,715 MW to serve our 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 Use Energy Efficiency

Beginning in 2008, AEP ramped up efforts to reduce energy consumption and peak demand through the introduction of additional energy efficiency and demand response programs. These programs, commonly and collectively referred to as demand side management, were implemented in jurisdictions where appropriate cost recovery was available. Since that time, AEP operating companies have implemented over 100 programs across the AEP service territory and in most of the states we serve. For the period 2008 through 2014, these programs have reduced annual consumption by over 5.2 million megawatt hours and peak demand by over 1,500 MW. To achieve these levels, AEP operating companies invested approximately \$700 million during the same period. These results are preliminary and subject to independent third party evaluation and verification of savings, as required.

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.

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 issues, including changes to environmental regulations and proposed regulation or legislation that could affect the Company. The Board's Committee on Directors and Corporate Governance oversees the Company's annual Corporate Accountability Report, which includes information about the Company's environmental, financial and social performance.

Other Environmental Issues and Matters

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 6 to the consolidated financial statements entitled Commitments, Guarantees and Contingencies, included in the 2014 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 2012, 2013 and 2014 and the current estimates for 2015, 2016 and 2017 are shown below, in each case including debt AFUDC. 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 generation 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 2014 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. The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the AEP System. We typically recover costs of complying with environmental standards from customers through rates in regulated jurisdictions. For our sales of energy into the markets, however, there is no such recovery mechanism. Failure to recover these costs could reduce our future net income and cash flows and possibly harm our financial condition. See Management's Discussion and Analysis of Financial Condition and Results of Operations under the heading entitled Environmental Issues and Note 6 to the consolidated financial statements, entitled Commitments, Guarantees and Contingencies, included in the 2014 Annual Reports, for more information regarding environmental expenditures in general.

Historical and Projected Environmental Investments

	2012 Actual	2013 Actual	2014 Actual	2015 Estimate	2016 Estimate	2017 Estimate
	(in thousands)					
Total AEP (a)	\$241,000	\$424,200	\$539,800	\$661,000	\$401,000	\$531,000
APCo	52,400	44,800	31,300	70,000	53,000	151,000
I&M	30,000	28,300	51,400	40,000	49,000	84,000
OPCo (b)	70,300	129,300	—	—	—	—
PSO	26,300	56,100	72,100	85,000	49,000	9,000
SWEPCo	24,200	135,700	225,300	316,000	86,000	66,000

(a) Includes expenditures of the subsidiaries shown and other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies. Excludes discontinued operations.

(b) OPCo transferred all of its generation assets on December 31, 2013.

BUSINESS SEGMENTS

Our reportable segments and their related business activities are outlined below. See Note 9 to the consolidated financial statements entitled Business Segments, included in the 2014 Annual Reports, for additional information on our operating segments.

Vertically Integrated Utilities

• Generation, transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEGCo, APCo, I&M, KGPCo, KPCo, PSO, SWEPCo and WPCo.

Transmission and Distribution Utilities

• Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by OPCo, TCC and TNC.

• OPCo purchases energy and capacity to serve remaining generation service customers.

AEP Transmission Holdco

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

Generation & Marketing

• Nonregulated generation in ERCOT and PJM.

• Marketing, risk management and retail activities in ERCOT, PJM and MISO.

AEP River Operations

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

VERTICALLY INTEGRATED UTILITIES

GENERAL

AEP's vertically integrated utility operations are engaged in the generation, transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEGCo, APCo, I&M, KGPCo, KPCo, PSO, SWEPCo and WPCo. AEPSC, as agent for AEP's public utility subsidiaries, performs marketing, generation dispatch, fuel procurement and power-related risk management and trading activities on behalf of each of these subsidiaries.

ELECTRIC GENERATION

Facilities and Coordination

As of December 31, 2014, AEP's vertically integrated public utility subsidiaries owned or leased approximately 26,900 MW of domestic generation. See Item 2 – Properties for more information regarding the generation capacity of

vertically integrated public utility subsidiaries.

Counterparty Risk Management

Counterparties and exchanges may require cash or cash related instruments to be deposited on transactions as margin against open positions. As of December 31, 2014, counterparties posted approximately \$9 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 \$53 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 2014 Annual Reports, under the heading entitled Quantitative and Qualitative Disclosures About Market Risk for additional information.

Fuel Supply

The 2012 and 2013 results include fuel used and transported by OPCo, a utility subsidiary that is not part of the Vertically Integrated Utilities segment. OPCo's results appear here because it retained its generation until year-end 2013 at which point all of its generation was transferred to AGR which transferred portions to APCo and KPCo.

The table shows the sources of fuel used by the Vertically Integrated Utilities:

	2014	2013	2012
Coal and Lignite	72%	75%	71%
Nuclear	16%	11%	11%
Natural Gas	11%	13%	17%
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 2014 fossil fuel costs for the Vertically Integrated Utilities were relatively unchanged on a dollar per MMBtu basis from 2013. A slight decline in the cost of coal was offset by an increase in natural gas prices, during the first half of 2014.

Coal and Lignite

AEP's Vertically Integrated Utilities 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 2014 was higher than 2013 due to strong demand in the East during the first half of the year, but coal inventories ended the year at target levels on a system basis.

Management believes that the Vertically Integrated Utilities 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 4,990 railcars, approximately 509 barges, 12 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 liquid, coal and other dry-bulk commodity transportation operations that are not part of this segment.

Spot market prices for coal decreased throughout 2014. The decreased spot coal prices during the year can be attributed to weak European coal demand, and relatively inexpensive natural gas, in the second half of 2014. Approximately half of the coal purchased by AEP is procured through term contracts. As those contracts expire, they are replaced with contracts at current market prices. The price impact of this process is reflected in subsequent periods. The price paid for coal delivered in 2014 decreased from the prior year primarily due to a decrease in spot coal prices and heavier reliance on shorter term contracts.

The following table shows the amount of coal and lignite delivered to the Vertically Integrated Utilities plants during the past three years and the average delivered price of coal purchased by the Vertically Integrated Utilities:

	2014	2013	2012
Total coal delivered to the plants (thousands of tons)	41,001	51,057	60,054
Average cost per ton of coal delivered	\$46.65	\$51.31	\$49.22

The coal supplies at the Vertically Integrated Utilities 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, 2014, the Vertically Integrated Utilities coal inventory was approximately 31 days of full load burn.

Natural Gas

The Vertically Integrated Utilities consumed over 96 billion cubic feet of natural gas during 2014 for generating power. This represents a decrease of 15% from 2013; 96.1 billion cubic feet in 2014 as compared to 112.4 billion cubic feet in 2013, excluding OPCo usage. While AEP's natural gas-fired generating capacity has increased over the past several years with the addition of the Stall and Dresden units, the implementation of the SPP Market and change in the dispatch of AEP's natural gas fleet resulted in a decreased natural gas-fired generation. Despite the availability of natural gas due to the increased shale supply, the U.S. pipeline infrastructure remains a limiting factor in the expansion of natural gas-fired generation. Several of AEP's natural gas-fired power plants are connected to at least two pipelines, however, which allow greater access to competitive supplies and improves delivery reliability. A portfolio of term, monthly, seasonal firm and daily peaking purchase 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 Vertically Integrated Utilities plants during the past three years and the average delivered price of natural gas purchased by the Vertically Integrated Utilities. Results for 2013 and 2012 include natural gas delivered to OPCo, while results for 2014 do not.

	2014	2013	2012
Total natural gas delivered to the plants (billion cubic feet)	96.1	158.3	220.0
Average price per MMBtu of purchased natural gas	\$4.70	\$4.01	\$3.01

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 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). The second loading of spent nuclear fuel into dry casks is expected to be completed in 2015.

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, 2014, the total decommissioning trust fund balance for the Cook Plant was approximately \$1.8 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 6 to the consolidated financial statements, entitled Commitments, Guarantees and Contingencies under the heading Nuclear Contingencies, included in the 2014 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.

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 AEGCo and KPCo, 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.

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 generation 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 financed capital expenditures totaling \$1.3 billion in connection with the engineering and construction of flue gas desulfurization projects and the associated scrubber waste disposal landfills at its two generation plants through debt issuances, including tax-advantaged debt issuances. Both OVEC generation plants are operating with the new environmental controls in service. OPCo attempted to assign its rights and obligations under the Inter-Company Power Agreement to an affiliate as part of its transfer of its generation assets and liabilities in keeping with corporate separation required by Ohio law. OPCo failed to obtain the consent to assignment from the other owners of OVEC and therefore filed a request with the PUCO seeking authorization to maintain its ownership of OVEC. In December 2013, the PUCO approved OPCo's request, subject to the condition that energy from the OVEC entitlements are sold into the day-ahead or real-time PJM energy markets, or on a forward basis through a bilateral arrangement. OPCo has filed an application with the PUCO to approve a purchased power agreement (PPA) rider that would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based purchase power agreement. The PPA would initially be based upon OPCo's contractual entitlement under the Inter-Company Agreement which is approximately 20% of OVEC's capacity.

ELECTRIC DELIVERY

General

Other than AEGCo, AEP's vertically integrated 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 vertically integrated 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 – Vertically Integrated Utilities – Regulation – Rates. The FERC regulates and approves the rates for both wholesale transmission transactions and wholesale generation contracts. See Item 1 – Vertically Integrated Utilities – Regulation – FERC. As discussed below, some transmission services also are separately sold to non-affiliated companies.

Other than AEGCo, AEP's vertically integrated 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 – Vertically Integrated Utilities – Competition.

The use and the recovery of costs associated with the transmission assets of the AEP vertically integrated public utility subsidiaries are subject to the rules, principles, protocols and agreements in place with PJM, SPP and ERCOT, and as approved by the FERC.

Transmission Agreement

APCo, I&M, KGPCo, KPCo and WPCo own and operate transmission facilities that are used to provide transmission service under the PJM OATT and are parties to the TA. OPCo, a subsidiary in our Transmission and Distribution Utilities segment, is also a party to the TA. The TA defines how the parties to the agreement share the revenues associated with their transmission facilities and the costs of transmission service provided by PJM. The TA has been approved by the FERC.

The following table shows the net charges allocated among the certain parties to the TA during the years ended December 31, 2014, 2013 and 2012:

Company	Years Ended December 31,		
	2014	2013	2012
	(in thousands)		
APCo	\$84,667	\$40,609	\$20,264
I&M	39,707	19,947	5,689

TCA, 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.

The following table shows the net (credits) or charges allocated pursuant to the TCA and SPP OATT protocols as described above for the years ended December 31, 2014, 2013 and 2012:

	Years Ended December 31,		
	2014	2013	2012
	(in thousands)		
PSO	\$14,100	\$14,700	\$12,300
SWEPCo	(14,100) (14,700) (12,300

Transmission Services for Non-Affiliates

In addition to providing transmission services in connection with their own power sales, AEP's vertically integrated public utility subsidiaries through RTOs also provide transmission services for non-affiliated companies. See Item 1 – Vertically Integrated Utilities – 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 was terminated effective June 1, 2014. It provided for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP East Companies and AEP West Companies. The System Transmission Integration Agreement functioned as an umbrella agreement in addition to the TA and the TCA. AEP's System Transmission Integration Agreement contained two service schedules that governed:

- ¶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 contemplated that additional service schedules may be added as circumstances warrant.

Regional Transmission Organizations

AEGCo, APCo, I&M, KGPCo, KPCo and WPCo are members of PJM, and PSO and SWEPCo 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.

REGULATION

General

AEP's vertically integrated public utility subsidiaries' retail rates and certain other matters are subject to traditional cost-based regulation by the state utility commissions. AEP's vertically integrated 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. 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 vertically integrated public utility subsidiaries are also subject to the regulatory provisions of EPACT, much of which is administered by the FERC.

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.

The rates of AEP's vertically integrated public utility subsidiaries are generally based on the cost of providing traditional bundled electric service (i.e., generation, transmission and distribution service). Historically, the state regulatory frameworks in the service area of the AEP vertically integrated public utility subsidiaries 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 4 to the consolidated financial statements, entitled Rate Matters, included in the 2014 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.

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.

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.

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's vertically integrated public utility subsidiaries 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. AEP's

vertically integrated public utility subsidiaries have market-based rate authority from the FERC, under which much of their wholesale marketing activity takes place. The FERC requires each public utility that owns or controls interstate transmission facilities to, directly or through an RTO, to 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. AEGCo, APCo, I&M, KGPCo, KPCo and WPCo are members of PJM. PSO and SWEPCo 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

The vertically integrated 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 vertically integrated 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 competitive position. With respect to alternative sources of energy, the vertically integrated 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 vertically integrated 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.

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TRANSMISSION AND DISTRIBUTION UTILITIES

GENERAL

This segment consists of the transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by OPCo, TCC and TNC. OPCo is engaged in the transmission and distribution of electric power to approximately 1,466,000 retail customers in Ohio. TCC is engaged in the transmission and distribution of electric power to approximately 817,000 retail customers through REPs in southern Texas. TNC is engaged in the transmission and distribution of electric power to approximately 189,000 retail customers through REPs in west and central Texas.

AEP's transmission and distribution 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 transmission and distribution utility subsidiaries in their service territories. These sales are made at rates approved by the PUCT for TCC and TNC and by the PUCO and the FERC for OPCo. The FERC regulates and approves the rates for wholesale transmission transactions. As discussed below, some transmission services also are separately sold to non-affiliated companies.

AEP's transmission and distribution 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.

The use and the recovery of costs associated with the transmission assets of the AEP transmission and distribution utility subsidiaries are subject to the rules, protocols and agreements in place with PJM and ERCOT, and as approved by the FERC. In addition to providing transmission services in connection with power sales in their service areas, AEP's transmission and distribution utility subsidiaries through RTOs also provide transmission services for non-affiliated companies.

Transmission Agreement

OPCo, together with APCo, I&M, KGPCo, KPCo and WPCo, is a party to the TA. The TA defines how the parties to the agreement share the cost of their transmission facilities. The TA has been approved by the FERC. OPCo's net charges allocated to it under the TA during the years ended December 31, 2014, 2013 and 2012 were \$17 million, \$8.9 million and \$6.1 million, respectively.

Regional Transmission Organizations

OPCo is a member of PJM, a FERC-approved RTO. 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. TCC and TNC are members of ERCOT.

REGULATION

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. 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. Transmission and distribution rates are established 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. The cost of service generally reflects operating expenses, including operation and maintenance expense, depreciation expense and taxes. 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.

FERC

Under the Federal Power Act, the FERC regulates rates for transmission of electric power, accounting and other matters. 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 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. 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.

SEASONALITY

The delivery of electric power is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months. In other areas, power demand peaks during the winter months. The pattern of this fluctuation may change due to the nature and location of AEP's transmission and distribution facilities. In addition, AEP transmission and distribution has historically delivered less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish AEP transmission and distribution's results of operations and may impact its financial condition. Conversely, unusually extreme weather conditions could increase AEP transmission and distribution's results of operations.

GENERATION & MARKETING

GENERAL

Our Generation & Marketing segment subsidiaries consist of competitive nonutility generating assets, a wholesale energy trading and marketing business and a retail supply and energy management business. The largest subsidiary in our Generation & Marketing segment is AGR. On December 31, 2013, AGR acquired the generation assets and related liabilities at net book value of OPCo in a series of transactions approved by the PUCO and the FERC. AGR transferred a portion of the generation assets and liabilities at net book value that it received to APCo and KPCo, and, in 2015 to WPCo. As a result of these transactions, AGR owns 9,159 MW of generating capacity, with rights to an additional 1,186 MW pursuant to a unit power agreement (see below). Other subsidiaries in this segment own or have the right to receive power from additional generation assets. See Item 2 – Properties for more information regarding the generation assets of the Generation & Marketing segment. AGR is a competitive generation subsidiary.

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, MISO and PJM. We sell power into the market and engage in power, natural gas, coal and emissions allowances risk management and trading activities.

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.

With respect to our retail supply and energy management business, our subsidiary AEP Energy is a retail energy 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 demand-side management solutions nationwide. AEP Energy had approximately 240,000 customer accounts as of December 31, 2014.

REGULATION

AGR is a public utility under the Federal Power Act, and is subject to FERC's exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Under the Federal Power Act, FERC has the authority to grant or deny market-based rates for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. FERC granted AGR market-based rate authority in December 2013. FERC's jurisdiction over ratemaking also includes the authority to suspend the market-based rates of utilities (including AGR, which is a public utility as defined by the FERC) and set cost-based rates if FERC subsequently determines that such utility can exercise market power, create barriers to entry or engage in abusive affiliate transactions. As a condition to the order granting AGR market-based rate authority, every three years AGR is required to file a market power update to show that it continues to meet FERC's standards with respect to generation market power and other criteria used to evaluate whether it continues to qualify for market-based rates. Other matters subject to FERC jurisdiction include, but are not limited to, review of mergers; and dispositions of jurisdictional facilities and acquisitions of securities of another public utility or an existing operational generating facility.

Specific operations of AGR are also subject to the jurisdiction of various other Federal, state, regional and local agencies, including Federal and state environmental protection agencies. We are also regulated by the PUCT for transactions inside ERCOT. Additionally, AGR is subject to mandatory reliability standards promulgated by the North American Electric Reliability Corporation, with the approval of FERC.

COMPETITION

The generation and marketing subsidiaries of AEP face competition for the sale of available power, capacity and ancillary services. The principal factors impacting us are electricity and fuel prices, new market entrants, construction or retirement of generating assets by others and technological advances in power generation. It is possible that changes in regulatory policies or advances in newer technologies for batteries or energy storage, fuel cells, microturbines, windmills and photovoltaic solar cells will reduce costs of new technology to levels that are equal to or below that of most central station electricity production. Our ability to maintain relatively low cost, efficient and reliable operations is a significant determinate of our competitiveness.

With over 70% of our generation fleet fueled by coal, our overall competitive position is impacted by the price of natural gas relative to coal. While higher relative natural gas prices generally favor our competitive position, lower relative natural gas prices will favor our competitors that have a higher concentration of natural gas fueled generation. Other factors impacting our competitiveness include environmental regulation, transmission congestion or transportation constraints at or near our generation facilities, inoperability or inefficiencies, outages and deactivations and retirements at our generation facilities.

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 months. The pattern of this fluctuation may change.

Counterparty Risk Management

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, 2014, counterparties posted approximately \$26 million in cash, cash equivalents or letters of credit with AEP for the benefit of AEP's generation and marketing subsidiaries (while, as of that date, AEP's generation and marketing subsidiaries posted approximately \$220 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 2014 Annual Reports, under the heading entitled Quantitative and Qualitative Disclosures About Market Risk for additional information.

Fuel Supply

The table shows the sources of fossil fuel used, on a heat basis, by AGR:

	2014
Coal	88%
Natural Gas	12%
Fuel Oil and other	< 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.

Coal and Consumables

AGR procures coal and consumables needed to burn the coal under a combination of purchasing arrangements including long-term and spot contracts with various producers and coal trading firms. As contracts expire, they are replaced, as needed, with contracts at market prices. Coal and consumable inventories remain adequate to meet generation requirements.

Management believes that AGR will be able to secure and transport coal and consumables of adequate quality and in adequate quantities to operate their coal fired units. AGR, through contracts, ownership and leases has the ability to adequately move and store coal and consumables for use in our generating facilities. AGR plants consumed 16.1 million tons of coal in 2014.

The coal supplies at AGR 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, coal quality, availability of acceptable coals, labor issues and weather conditions, which may interrupt production or deliveries. As of December 31, 2014, AGR's coal inventory was adequate to meet the generation demand of the coal fleet.

Natural Gas

Despite the availability of natural gas due to the increased shale supply, the U.S. pipeline infrastructure remains a limiting factor in the expansion of natural gas-fired generation. A portfolio of term, monthly, seasonal firm and daily peaking purchase 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. AGR plants consumed 50 billion cubic feet of natural gas in 2014, an increase of approximately 9% from 2013.

Certain Power Agreements

AEGCo

The Unit Power Agreement between AEGCo and AGR (assigned from OPCo) dated March 15, 2007, provides for the sale by AEGCo to AGR of all the capacity and associated unit contingent energy and ancillary services available to AGR from the Lawrenceburg Plant, a 1,186 MW natural gas-fired unit owned by AEGCo. AGR 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 AGR, 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.

OPCo

Pursuant to a Power Supply Agreement (PSA) between AGR and OPCo, AGR supplies capacity for OPCo's switched and non-switched retail load for the period January 1, 2014 through May 31, 2015. AGR also supplied the energy needs of OPCo's non-switched retail load that was not acquired through auctions from January 1, 2014 through December 31, 2014 under the PSA.

Other

As of December 31, 2014, 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 355 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.

AEP TRANSMISSION HOLDCO (AEPTHCO)

GENERAL

AEPTHCo is a holding company for (a) AEP's transmission joint ventures and (b) AEPTCo, which is the direct holding company for the seven wholly-owned FERC-regulated transmission-only electric utilities (Transcos) listed below, each of which is geographically aligned with our existing utility operating companies.

AEPTCo TRANSCOS

AEP East Transmission Companies (all located 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 located within SPP)

- ▲AEP Oklahoma Transmission Company, Inc. (OKTCo)

▲EP Southwestern Transmission Company, Inc. (SWTCo) (covering Louisiana)

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 customer points of delivery, generation interconnections, new facilities to provide transmission service directed by the RTOs, and new facilities required to maintain grid reliability.
- 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 and retirement of generation facilities.

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 and the transmission operations of OPCo. APTCo, IMTCo, KTCo, OHTCo, OKTCo and WVTCo have received approvals for formation or did not require state commission approval to operate. IMTCo, KTCo, OHTCo, OKTCo and WVTCo currently own and operate transmission assets or have assets under construction. APTCo requires approval from the Virginia SCC on a project by project basis. The APSC has denied SWTCo's application to operate in Arkansas. An application for regulatory approval for SWTCo is under consideration in Louisiana. As of December 31, 2014, AEPTCo had \$1.8 billion of transmission assets in-service with plans to construct approximately \$3 billion of additional transmission assets through 2017.

JOINT VENTURE INITIATIVES

AEP has established joint ventures with other electric utility companies for the purpose of developing, building, and owning transmission assets that seek to improve reliability and market efficiency and provide transmission access to remote generation sources in North America.

We are currently participating in the following joint venture initiatives:

Joint Venture Name	Location	Projected or Actual Completion Date	Owners (Ownership %)	Total Estimated Project Costs at Completion (in thousands)	AEP's Investment as of December 31, 2014 (h)	Approved Return on Equity
ETT	Texas (ERCOT)	(a)	Berkshire Hathaway Energy (50%) AEP (50%)	\$3,100,000 (a)	\$503,910	9.96 %
Prairie Wind	Kansas	2014	Westar Energy (50%) Berkshire Hathaway Energy (25%) (b) AEP (25%) (b)	161,500	18,071	12.8 %
Pioneer	Indiana	2018	(c) Duke Energy (50%) AEP (50%)	1,100,000 (c)	4,943	12.54 %
RITELine IN	Indiana	2026	Exelon (12.5%) (d) AEP (87.5%) (d)	400,000	80	(e) 11.43 %
RITELine IL	Illinois	2026	Commonwealth Edison (75%) Exelon (12.5%) (d) AEP (12.5%) (d)	1,200,000	3	(e) 11.43 %
Transource Missouri	Missouri	2017	Great Plains Energy (13.5%) (f) AEP (86.5%) (f)	398,000 (g)	26,295	11.1 % (g)

ETT is undertaking multiple projects and the completion dates will vary for those projects. ETT's investment in (a) completed, current and future projects in ERCOT over the next ten years is expected to be \$3.1 billion. Future projects will be evaluated on a case-by-case basis.

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

- The Pioneer project consists of approximately 286 miles of new 765 kV transmission lines, which is estimated to cost \$1.1 billion at completion. Pioneer is developing the first 66-mile segment jointly with Northern Indiana Public Service Company at a total estimated cost of \$350 million. The projected completion date for the first 66-mile segment is 2018. The projected completion dates for the remaining segments have not been determined.
- (c) AEP owns 87.5% of RITELine Indiana, LLC (RITELine IN) through its ownership interest in RITELine Transmission Development, LLC (RTD) and AEP Transmission Holding Company, LLC (AEPTHCo). AEP owns (d) 12.5% of RITELine Illinois, LLC (RITELine IL) through its ownership interest in RTD. RTD is a 50/50 joint venture with Exelon Transmission Company, LLC and AEPTHCo.
- RITELine IN is a consolidated variable interest entity. RTD received an order from the FERC in October 2011 (e) granting incentives for the RITELine IN and RITELine IL projects. The projects and other segments that are electrically equivalent in nature are currently under consideration for inclusion in the interregional planning process between PJM and MISO.
- (f) AEP owns 86.5% of Transource Missouri through its ownership interest in Transource Energy, LLC (Transource). Transource is a joint venture with AEPTHCo and Great Plains Energy formed to pursue competitive transmission projects. AEPTHCo and Great Plains Energy own 86.5% and 13.5% of Transource, respectively.
- The ROE represents the weighted average approved return on equity based on the projected costs of two projects (g) currently under development by Transource Missouri: the \$65 million Iatan-Nashua project (10.3%) and the \$333 million Sibley-Nebraska City project (11.3%).
- RITELine IN and Transource Missouri are consolidated joint ventures by AEP. Therefore, the investment value (h) listed reflects applicable income taxes that are the responsibility of AEP. All other investments in this schedule are joint ventures that are not consolidated by AEP. Therefore, these investment values listed do not reflect income taxes that are the responsibility of AEP.

Our joint ventures do not have employees. Business services for the joint ventures are provided by AEPSC and other AEP subsidiaries and the joint venture partners. During 2014 approximately 665 AEPSC employees and 260 operating company employees provided service to one or more joint ventures. The amount of service provided was equal to the service of approximately 195 full-time employees.

REGULATION

The Transcos and joint ventures located outside of ERCOT establish transmission rates annually through forward looking formula rate filings with the FERC pursuant to FERC-approved implementation protocols. The protocols include a transparent, formal review process to ensure the updated transmission rates are prudently incurred and reasonably calculated.

The Transcos' and joint ventures' (where applicable) rates are included in the respective OATT for PJM and SPP. 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. The FERC requires transmission providers such as PJM and SPP to offer transmission service to all eligible customers (for example, load-serving entities, power marketers, generators and customers) on a non-discriminatory basis.

The FERC-approved formula rates establish the annual transmission revenue requirement (ATRR) and transmission service rates for transmission owners in annual rate base filings with FERC. The formula rates establish rates for a one-year period based on the current projects in-service and proposed projects for a defined timeframe. The formula rates also include a true-up calculation for the previous year's billings, allowing for over- and under-recovery of the transmission owner's ATRR. PJM and SPP pay the transmission owners their ATRR for use of their facilities and bill transmission customers taking service under the PJM and SPP OATTs, based on the terms and conditions in the respective OATT for the service taken.

The 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.

In the annual rate based filings described above, the Transcos in aggregate filed rate base totals of \$1,448 million in 2014, \$776 million for 2013 and \$283 million for 2012. The total transmission revenue requirement filed in the ATRR, including prior year over/under recovery of revenue and associated carrying charges, for 2014, 2013 and 2012 was \$229 million, \$107 million and \$35 million, respectively.

The rates of ETT, which is located in ERCOT, are determined by the PUCT. ETT sets its rates through a combination of base rate cases and interim Transmission Costs of Services (TCOS) filings. ETT may file interim TCOS filings semi-annually to update its rates to reflect changes in its net invested capital.

Our joint ventures have approved returns on equity ranging from 9.96% to 12.8% based on equity capital structures ranging from 40% to 60%.

COMPETITION

One of the most significant provisions of FERC Order No. 1000 is the removal of the federal right of first refusal for incumbent utilities within tariffs and agreements for certain regional transmission projects. Historically, vertically integrated public utilities had the right to build and own transmission lines proposed by the region's planning processes

when those lines connected to facilities within their respective retail service territories. FERC Order No. 1000 eliminates the federal right of first refusal in regional transmission organization (RTO) tariffs for incumbent utilities to construct certain regional transmission projects within their own service territories, thereby creating the opportunity for any qualified entity to build and own regional transmission facilities in any service territory. Transource was created to respond to FERC Order No. 1000 competitive processes at the RTO level.

AEP RIVER OPERATIONS

Our AEP River Operations segment transports liquid, 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 generation plants. AEP River Operations includes approximately 2,300 barges, 37 towboats and 18 harbor boats that we own or lease. In 2015, River Operations will operate its current fleet of 40 ten thousand barrel tank barges and may add an additional 40 ten thousand barrel tank barges throughout the year. 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 – Vertically Integrated Utilities – 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 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.

EXECUTIVE OFFICERS OF AEP as of February 20, 2015

The following persons are executive officers of AEP. Their ages are given as of February 1, 2015. The officers are appointed annually for a one-year term by the board of directors of AEP.

Nicholas K. Akins

Chairman of the Board, President and Chief Executive Officer

Age 54

Chairman of the Board since January 2014, President since January 2011 and Chief Executive Officer since November 2011. Was Executive Vice President – Generation from September 2006 to December 2010.

Lisa M. Barton

Executive Vice President – Transmission

Age 49

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 45

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 54

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 55

Executive Vice President – Generation of AEPSC since January 2011. Was Senior Vice President – Fossil & Hydro Generation of AEPSC from February 2008 to December 2010.

Robert P. Powers

Executive Vice President and Chief Operating Officer

Age 61

Executive Vice President and Chief Operating Officer since November 2011. Was President – Utility Group from April 2009 to November 2011.

Brian X. Tierney

Executive Vice President and Chief Financial Officer

Age 47

Executive Vice President and Chief Financial Officer since October 2009.

Dennis E. Welch

Executive Vice President and Chief External Officer

Age 63

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.

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Charles E. Zebula

Executive Vice President – Energy Supply

Age 54

Executive Vice President – Energy Supply since January 2013. Was Senior Vice President – Investor Relations and Treasurer from September 2008 to December 2012.

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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.

Our regulated electric revenues, earnings and results are dependent on state regulation that may limit our ability to recover costs and other amounts. – Affecting each Registrant

The rates our customers pay to our regulated utility businesses are subject to approval by the FERC and the respective state utility commissions of Ohio, Texas, Virginia, West Virginia, Oklahoma, Indiana, Louisiana, Kentucky, Arkansas, Michigan and Tennessee. If our regulated utility earnings exceed the returns established by the relevant commissions, retail electric rates may be subject to review and possible reduction by the commissions, which may decrease our future earnings. Additionally, if regulatory bodies do not allow recovery of costs incurred in providing service on a timely basis, it could reduce future net income and cash flows and impact financial condition. Similarly, if recovery or other rate relief authorized in the past is overturned or reversed on appeal, our future earnings could be negatively impacted. Any regulatory action or litigation outcome that triggers a reversal of a regulatory asset or deferred cost, including fuel and related costs, generally results in an impairment to the balance sheet and a charge to the income statement of the company involved.

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

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, if states were to limit or restrict such policies, 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, or if one or more states were to successfully limit FERC jurisdiction on recovery of costs on transmission investment and its return, 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.

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. 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 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.

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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 cyber insurance to cover liabilities and losses directly arising from a potential cyber event. We also maintain property and casualty insurance that may cover certain resultant physical damage or third-party injuries caused by potential cyber events. However, damage and claims arising from such incidents may exceed the amount of any insurance available and other damage and claims arising from such incidents may not be covered at all. 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 cyber security program designed to protect and preserve the confidentiality, integrity and availability of data and systems. In addition, we are subject to mandatory cyber security regulatory requirements. However, cyber threats continue to evolve and adapt, and, as a result, there is a risk that we could experience a successful cyber attack despite our current security posture and regulatory compliance efforts.

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

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

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

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

Our power trading business relies on the investment grade ratings of our individual public utility subsidiaries' senior unsecured long-term debt or on the investment grade ratings of AEP. 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 future net income and cash flows and impact financial condition.

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

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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. AEP indebtedness and common stock dividends are structurally subordinated to all subsidiary indebtedness.

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 reduce future net income and cash flows and impact 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, prevailing economic conditions may reduce our future net income and cash flows and impact financial condition.

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 future net income and cash flows may be reduced.

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. We have existing contracts of varying durations for the supply of coal, 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 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 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 could reduce future net income and cash flows and impact financial condition.

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, as those transactions are marked to market, those transactions may reduce future results of operations and cash flows and impact financial condition.

Our AEP River Operations segment is subject to risks that are beyond our control. – Affecting AEP

Our AEP River Operations segment transports liquid, coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi rivers. These activities can be hazardous and depend on natural conditions and forces. Our river transport operations could result in an environmental event such as a serious spill or release. In addition, 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 were near the lowest since the levels caused by severe drought in 1988. Water levels during 2014 were improved and generally considered favorable for barge operations. Any reduction in the commercial activities of our AEP River Operations due to extreme water levels could reduce future net income and cash flows.

We are subject to physical and financial risks associated with climate change. – Affecting each Registrant

Climate change creates physical and financial risk. Physical risks from climate change include an increase in sea level and changes in weather conditions, such as changes in precipitation and extreme weather events. Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes.

Increased energy use due to weather changes may require us to invest in additional generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather changes may affect our financial condition, through decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stress, including service interruptions. Weather conditions outside of our service territory could also have an impact on our revenues. We buy and sell electricity depending upon system needs and market opportunities. Extreme weather conditions creating high energy demand on our own and/or other systems may raise electricity prices as we buy short-term energy to serve our own system, which would increase the cost of

energy we provide to our customers.

Severe weather impacts our service territories, primarily when thunderstorms, tornadoes, hurricanes and snow or ice storms occur. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. Changes in precipitation resulting in droughts or water shortages could adversely affect our operations, principally our fossil generating units. A negative impact to water supplies due to long-term drought conditions could adversely impact our ability to provide electricity to customers, as well as increase the price they pay for energy. We may not recover all costs related to mitigating these physical and financial risks.

To the extent climate change impacts a region's economic health, it may also impact our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods and services, has an impact on the economic health of our communities.

We cannot predict the outcome of the legal proceedings relating to our business activities. – Affecting each Registrant

We are involved in legal proceedings, claims and litigation arising out of our business operations, the most significant of which are summarized in Note 6 of the Notes to Consolidated Financial Statements entitled Commitments, Guarantees and Contingencies. Adverse outcomes in these proceedings could require significant expenditures that could reduce future net income and cash flows and impact financial condition.

RISKS RELATING TO STATE RESTRUCTURING

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

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 customer switching in Ohio continues, it could reduce AGR's future net income and cash flows and impact financial condition.

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 2014, TCC's largest REP accounted for 25% of its operating revenue and its second largest REP accounted for 23% of its operating revenue; TNC's largest REP accounted for 11% of its operating revenues, and its second largest REP accounted for 9% 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 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 generation 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

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impact financial condition, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed or additional substances become regulated. If we retire generation 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. We typically recover our expenditures for pollution control technologies, replacement generation, undepreciated plant balances and associated operating costs from customers through regulated rates in regulated jurisdictions. Failure to recover these costs could reduce our future net income and cash flows and possibly harm our financial condition. For our sales of energy from our competitive units, there is no such cost-recovery mechanism. As a result, we may not recover our costs through the market and we may be forced to shut competitive units down. The costs of compliance for our competitive units could reduce our future net income and cash flows and possibly harm our financial condition.

Regulation of CO₂ emissions 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 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. Several groups have filed challenges to the endangerment finding and the Federal EPA's subsequent rulemakings. The Supreme Court agreed to review whether the Federal EPA reasonably determined that establishing standards for new motor vehicles automatically triggered regulation of stationary sources through the prevention of significant deterioration and Title V permitting programs, and determined that the Federal EPA was neither compelled nor authorized to automatically regulate stationary sources of CO₂ emissions under these programs, but that the Federal EPA could establish requirements for best available control technology reviews of CO₂ emissions for sources otherwise required to obtain a Prevention of Significant Deterioration permit if their emissions exceed a reasonable level. The Federal EPA must undertake additional rulemaking to establish such requirements and a reasonable level.

In 2012, the Federal EPA issued a proposed CO₂ emissions standard for new power generation sources. In response to the comments submitted on this proposed rule, and in accordance with a directive from the President, the Federal EPA withdrew the April 2012 proposed rule and has issued a new proposal. This proposed rule includes separate, but equivalent, standards for natural gas and coal-fired units, based on the use of partial carbon capture and storage at coal units. In June 2014, the Federal EPA issued standards for modified and reconstructed units, and a guideline for the development of state implementation plans that would reduce carbon emissions from existing utility units. The guidelines for existing sources include aggressive emission rate goals that are composed of a number of measures. 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 AEP and our customers.

CO₂ standards could require significant increases in capital expenditures and operating costs and could impact the dates for retirement of our coal-fired units. We typically recover costs of complying with new requirements such as the potential CO₂ and other greenhouse gases emission standards from customers through regulated rates in regulated jurisdictions. For our sales of energy into the markets, however, there is no such recovery mechanism. Failure to recover these costs, should they arise, could reduce our future net income and cash flows and possibly harm our financial condition.

We may be harmed if our merchant generation fleet is not profitable or loses value. – Affecting AEP

We are evaluating strategic alternatives for our merchant generation fleet, which primarily includes AGR's generation fleet which operates in PJM and a 54.7% interest in the Oklaunion Plant which operates in ERCOT. Potential alternatives may include, but are not limited to, continued operation of the merchant generation fleet, executing a PPA with a regulated affiliate for certain merchant generation units in Ohio, a spin-off of the merchant generation fleet or a sale of the merchant generation fleet. We have not made a decision regarding the potential alternatives, nor have we set a specific timeframe for a decision. Certain of these alternatives could result in a loss which could reduce future net income and cash flow and impact financial condition.

Amounts we receive from the results of PJM capacity auctions associated with our nonregulated generation assets could fail to adequately compensate us. – Affecting AEP

Financial returns on AGR's generation capacity are subject to the results of annual PJM capacity auctions. Recent auction results indicate a great deal of volatility and the possibility of clearing prices substantially lower than the cost of such capacity. We expect a significant decline in AGR capacity revenues after May 2015 when the Power Supply Agreement between AGR and OPco ends. Additionally, we expect a decline in AGR capacity revenues from June 2016 through May 2017 based upon the decrease in the PJM base auction price. PJM recently proposed at FERC a set of supplemental auctions for 2016/17 and 2017/18. Those auctions may mitigate the decline in capacity revenues. However, this proposal has not yet been accepted at FERC and we can give no assurance that the FERC will approve the proposal. If the PJM capacity auctions continue to result in clearing prices lower than the cost of our capacity, it could reduce our future net income and cash flows and impact financial condition.

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

In the past, there have been several cases seeking damages based on allegations of federal and state common law nuisance in which we, among others, were defendants. In general, the actions allege that emissions from the defendants' power plants constitute a public nuisance. The plaintiffs in these actions generally seek recovery of damages and other relief. If 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 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.

Changes in technology and regulatory policies may lower the value of our generating facilities. – Affecting each Registrant

We primarily generate electricity at large central facilities. This method results in economies of scale and lower costs than (a) newer technologies such as fuel cells, microturbines, wind turbines and photovoltaic solar cells and (b) distributed generation using either new or existing technology. Other technologies, such as light emitting diodes (LEDs), increase the efficiency of electricity and, as a result, lower the demand for it. It is possible that advances in technologies, the availability of distributed generation or changes in regulatory policies will lower the demand for electricity or reduce the costs of new technology to levels that are equal to or below that of most central station electricity production, either of which could have a material adverse effect on our results of operations.

Our profitability is impacted by our continued authorization to sell power at market-based rates. – Affecting each Registrant

FERC has granted AGR, APCo, I&M, KPCo, OPCo, PSO and SWEPco authority to sell electricity at market-based rates. FERC reserves the right to revoke or revise this market-based rate authority if it subsequently determines that one or more of these companies can exercise market power in transmission or generation, create barriers to entry or engage in abusive affiliate transactions. Each company that has obtained market-based rate authority from FERC must file a market power update every three years to show that they continue to meet FERC's standards with respect to generation market power and other criteria used to evaluate whether entities qualify for market-based rates. The loss of market-based rate authority by any of these entities, especially by AGR, could have a material adverse effect on our results of operations.

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 and/or incentives.

Commodity trading and marketing activities are subject to inherent risks which can be reduced and controlled but not eliminated. – Affecting each Registrant

We attempt to manage the exposure of our power trading activities 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 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.

We may not successfully manage the uncertainty involved with our power trading (including coal, natural gas and emission allowances trading and power marketing). – Affecting each Registrant

Our power trading activities also expose us to risks of commodity price movements. To the extent that our power trading does not hedge the price risk associated with the generation it owns, or controls, through long-term power purchase agreements, we would be exposed to the risk of rising and falling spot market prices.

For example, the use of new technologies to recover natural gas from shale deposits has increased natural gas supply and reserves, placing further downward pressure on natural gas prices, and has reduced the need for our coal-fired generation. Further, in the event that alternative generation resources, such as wind and solar, are mandated or otherwise subsidized or encouraged through climate legislation or regulation and added to the available generation supply, such resources could displace a higher marginal cost fossil plant, which could reduce the price at which market participants sell their electricity. This occurrence could then reduce the market price at which all generators in that region would be able to sell their output. These events could adversely affect our financial condition, results of operations and cash flows, and could also result in an impairment of certain long-lived assets.

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.

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, 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

GENERATION FACILITIES

As of December 31, 2014 the AEP System owned (or leased where indicated) generation plants, all situated in the states in which our electric utilities serve retail customers, where applicable, with net maximum power capabilities (winter rating) shown in the following tables:

Vertically Integrated Utilities Segment

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 (b)	6	IN	Natural Gas	1,186	2004
Total MWs				2,496	

(a) Rockport, Unit 2 is leased.

(b) The capacity and output of this plant is under contract to (and its financial impact is included with) AGR through 2017.

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	613	2012
Smith Mountain	5	VA	Pumped Storage	586	1965
Amos	3	WV	Steam - Coal	2,900	1971
Clinch River	3	VA	Steam - Coal	705	1958
Glen Lyn	2	VA	Steam - Coal	322	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				7,877	

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.

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

	Cook Plant		
	Unit 1	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			
2014	87.4	% 96.3	%
2013	82.7	% 86.9	%
2012	96.9	% 87.4	%
2011	81.3	% 99.4	%
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
Mitchell (a)	2	WV	Steam - Coal	780	1971
Total MWs				1,858	

(a) KPCo owns a 50% interest in the Mitchell Units. As of December 31, 2014, AGR owned the remaining 50% which it transferred to WPCo on January 31, 2015.

PSO

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Comanche	3	OK	Natural Gas	266	1973
Riverside, Units 3 and 4	2	OK	Natural Gas	152	2008
Southwestern, Units 4 and 5	2	OK	Natural Gas	170	2008
Tulsa	2	OK	Natural Gas	318	1956
Weleetka	3	OK	Natural Gas	198	1975
Northeastern, Units 3 and 4	2	OK	Steam - Coal	937	1979
Oklauinion (a)	1	TX	Steam - Coal	102	1986
Northeastern, Units 1 and 2	2	OK	Steam - Natural Gas	923	1961
Riverside, Units 1 and 2	2	OK	Steam - Natural Gas	908	1974
Southwestern, Units 1, 2 and 3	3	OK	Steam - Natural Gas	462	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	313	2007
Stall	1	LA	Natural Gas	534	2010
Flint Creek (a)	1	AR	Steam - Coal	264	1978
Turk (a)	1	AR	Steam - Coal	477	2012
Welsh	3	TX	Steam - Coal	1,584	1977
Dolet Hills (a)	1	LA	Steam - Lignite	257	1986
Pirkey (a)	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 (b)	4	LA	Steam - Natural Gas	242	1947
Lone Star	1	TX	Steam - Natural Gas	50	1954
Wilkes	3	TX	Steam - Natural Gas	893	1964
Total MWs				5,779	

(a) Jointly-owned with nonaffiliated entity(ies). Figures presented reflect only the portion owned by SWEPCo.

(b) Unit 1 was inactive in 2014.

Generation & Marketing Segment

AGR (formerly owned by 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
Cardinal	1	OH	Steam - Coal	595	1967
Conesville (a)	3	OH	Steam - Coal	1,159	1957
Gavin	2	OH	Steam - Coal	2,670	1974
Kammer	3	WV	Steam - Coal	630	1958
Mitchell (b)	2	WV	Steam - Coal	780	1971
Muskingum River	5	OH	Steam - Coal	1,380	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(c)				9,939	

(a) Jointly-owned with nonaffiliated entities. Figures presented reflect only the portion owned by AGR.

(b) As of December 31, 2014, AGR owned a 50% interest in the Mitchell Units which it transferred to WPCo on January 31, 2015. KPCo owns the remaining 50%.

(c) AGR has contractual rights through 2017 to a natural gas-fired 1,186 MW generating unit located in Lawrenceburg, IN.

Domestic Independent Power

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	

In addition to the AGR and Domestic Independent Power generation set forth above, a subsidiary in the Generation & Marketing segment has contractual rights through 2027 from TNC to 355 MWs from the Oklaunion Generating Plant, a coal-fired unit located in Vernon, TX. TNC co-owns the Oklaunion Generating Plant with PSO and several non-affiliated entities.

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:

Vertically Integrated Utilities Segment

	Total Overhead Circuit Miles of Transmission and Distribution Lines	Circuit Miles of 765kV Lines
APCo	51,612	733
I&M	21,868	616
KGPCo	1,401	—
KPCo	11,171	257
PSO	20,877	—
SWEPCo	27,434	—
WPCo	1,731	—
Total Circuit Miles	136,094	1,606

Transmission and Distribution Utilities Segment

	Total Overhead Circuit Miles of Transmission and Distribution Lines	Circuit Miles of 765kV Lines
OPCo (a)	45,486	507
TCC	29,515	—
TNC	17,127	—
Total Circuit Miles	92,128	507

(a) Includes 766 miles of 345,000 volt jointly owned lines.

AEP Transmission Holdco Segment

The following table sets forth the total overhead circuit miles of transmission lines of ETT, IMTCo, OHTCo, and OKTCo, none of which own 765 kV lines:

	Total Overhead Circuit Miles of Transmission Lines
ETT	1,528
IMTCo	30
OHTCo	161
OKTCo	256
Total Circuit Miles	1,975

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.

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SYSTEM TRANSMISSION LINES AND FACILITY SITING

Laws in the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Tennessee, Texas, 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 \$4.5 billion of construction expenditures for 2015, including debt AFUDC 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. For additional information on our construction program, see Combined Management's Narrative Discussion and Analysis under the heading entitled Budgeted Construction Expenditures for each Registrant.

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 generation 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 6 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 6 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. SWEP Co, through its ownership of Dolet Hills Lignite Company (DHLC), a wholly-owned lignite mining subsidiary of SWEP Co, and AGR, through its use of the Conner Run fly ash impoundment, is subject to the provisions of the Mine Act.

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 and Conner Run under the Mine Act for the quarter ended December 31,

2014.

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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 14 to the consolidated financial statements entitled Financing Activities under the heading Dividend Restrictions in the 2014 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 2014, 2013 and 2012 are incorporated by reference to the material under Statements of Changes in Common Shareholder's Equity and Note 14 to the consolidated financial statements entitled Financing Activities under the heading Dividend Restrictions in the 2014 Annual Reports.

During the quarter ended December 31, 2014, 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 2014 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 2014 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 2014 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 2014 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 Risk in the 2014 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 2014, management, including the principal executive officer and principal financial officer of each of American Electric Power Company, Inc. ("AEP"), 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 Registrant 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, 2014, 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 2014 that materially affected, or is reasonably likely to materially affect, the Registrants' internal control over financial reporting

Management assessed and reported on the effectiveness of its internal control over financial reporting as of December 31, 2014. As a result of that assessment, management determined that there were no material weaknesses as of December 31, 2014 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 2014 Annual Report of each Registrant.

ITEM 9B. OTHER INFORMATION

None.

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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 2015 Annual Meeting of Shareholders (the 2015 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 2015 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 2015 Annual Meeting including under the captions "Compensation Discussion and Analysis," "Executive Compensation", "Director

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Compensation” and “2014 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 2015 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, 2014:

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 (a)
Equity Compensation Plans Approved by Security Holders	—	NA	15,825,643
Equity Compensation Plans Not Approved by Security Holders	—	—	—
Total	—	NA	15,825,643

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 (a) under the Amended and Restated American Electric Power System Long-Term Incentive Plan. The number of shares available under this plan would be 2,809,209 higher if equity compensation that is paid in cash were not deducted from this column.

NA Not applicable.

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 2015 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 2015 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 2015 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, 2014 and 2013, 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	
	2014	2013	2014	2013	2014	2013
Audit Fees	\$2,103,482	\$2,342,744	\$1,563,434	\$1,552,346	\$1,111,667	\$3,119,885
Audit-Related Fees	108,305	104,923	53,508	51,488	83,594	128,535
Tax Fees	26,915	22,556	21,117	16,677	15,719	278,029
Total	\$2,238,702	\$2,470,223	\$1,638,059	\$1,620,511	\$1,210,980	\$3,526,449
		PSO		SWEPCo		
		2014	2013	2014	2013	
Audit Fees		\$599,890	\$641,720	\$1,216,430	\$1,131,155	
Audit-Related Fees		25,622	21,920	41,118	102,633	
Tax Fees		8,482	7,100	15,503	12,505	
Total		\$633,994	\$670,740	\$1,273,051	\$1,246,293	

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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, 2014, 2013 and 2012; Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2014, 2013 and 2012; Consolidated Statements of Changes in Equity for the years ended December 31, 2014, 2013 and 2012; Consolidated Balance Sheets as of December 31, 2014 and 2013; Consolidated Statements of Cash Flows for the years ended December 31, 2014, 2013 and 2012; Notes to Consolidated Financial Statements.

APCo, I&M and OPCo:

Consolidated Statements of Income for the years ended December 31, 2014, 2013 and 2012; Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2014, 2013 and 2012; Consolidated Statements of Changes in Common Shareholder's Equity for the years ended December 31, 2014, 2013 and 2012; Consolidated Balance Sheets as of December 31, 2014 and 2013; Consolidated Statements of Cash Flows for the years ended December 31, 2014, 2013 and 2012; 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, 2014, 2013 and 2012; Statements of Comprehensive Income (Loss) for the years ended December 31, 2014, 2013 and 2012; Statements of Changes in Common Shareholder's Equity for the years ended December 31, 2014, 2013 and 2012; Balance Sheets as of December 31, 2014 and 2013; Statements of Cash Flows for the years ended December 31, 2014, 2013 and 2012; 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, 2014, 2013 and 2012; Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2014, 2013 and 2012; Consolidated Statements of Changes in Equity for the years ended December 31, 2014, 2013 and 2012; Consolidated Balance Sheets as of December 31, 2014 and 2013; Consolidated Statements of Cash Flows for the years ended December 31, 2014, 2013 and 2012; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting.

2. FINANCIAL STATEMENT SCHEDULES:

Financial Statement Schedules are listed in the Index of Financial Statement Schedules. (Certain schedules have been omitted because the required information is contained in the notes to financial statements or because such schedules are not required or are not applicable). Reports of Independent Registered Public Accounting Firm.

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Number

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3. EXHIBITS:

E-1

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.

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 20, 2015

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)	Chairman of the Board, Chief Executive Officer and Director	February 20, 2015
(ii) Principal Financial Officer:		
/s/ Brian X. Tierney (Brian X. Tierney)	Executive Vice President and Chief Financial Officer	February 20, 2015
(iii) Principal Accounting Officer:		
/s/ Joseph M. Buonaiuto (Joseph M. Buonaiuto)	Senior Vice President, Controller and Chief Accounting Officer	February 20, 2015
(iv) A Majority of the Directors:		
*Nicholas K. Akins		
*David J. Anderson		
* J. Barnie Beasley, Jr.		
* Ralph D. Crosby, Jr.		
*Linda A. Goodspeed		
*Thomas E. Hoaglin		
*Sandra Beach Lin		
*Richard C. Notebaert		
*Lionel L. Nowell, III		
*Stephen S. Rasmussen		
*Oliver G. Richard, III		
*Sara Martinez Tucker		
*By: /s/ Brian X. Tierney (Brian X. Tierney, Attorney-in-Fact)		February 20, 2015

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 20, 2015

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)	Chairman of the Board, Chief Executive Officer and Director February 20, 2015
(ii)	Principal Financial Officer:	
	/s/ Brian X. Tierney (Brian X. Tierney)	Vice President, Chief Financial Officer and Director February 20, 2015
(iii)	Principal Accounting Officer:	
	/s/ Joseph M. Buonaiuto (Joseph M. Buonaiuto)	Controller and Chief Accounting Officer February 20, 2015
(iv)	A Majority of the Directors:	

*Nicholas K. Akins
*Lisa M. Barton
*David M. Feinberg
*Lana L. Hillebrand
*Mark C. McCullough
*Robert P. Powers
Brian X. Tierney
*Dennis E. Welch

*By:

/s/ Brian X. Tierney
(Brian X. Tierney,
Attorney-in-Fact)

February 20,
2015

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 20, 2015

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)	Chairman of the Board, Chief Executive Officer and Director	February 20, 2015
(ii) Principal Financial Officer:		
/s/ Brian X. Tierney (Brian X. Tierney)	Vice President, Chief Financial Officer and Director	February 20, 2015
(iii) Principal Accounting Officer:		
/s/ Joseph M. Buonaiuto (Joseph M. Buonaiuto)	Controller and Chief Accounting Officer	February 20, 2015
(iv) A Majority of the Directors:		
*Nicholas K. Akins		
*Lisa M. Barton		
*Paul Chodak, III		
*Thomas A. Kratt		
*Marc E. Lewis		
*David A. Lucas		
*Mark C. McCullough		
*Robert P. Powers		
*Carla E. Simpson		
Brian X. Tierney		
*Barry O. Wiard		

*By: /s/ Brian X. Tierney
(Brian X. Tierney, Attorney-in-Fact)

February 20, 2015

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INDEX OF FINANCIAL STATEMENT SCHEDULES

	Page Number
<u>Reports of Independent Registered Public Accounting Firm</u>	<u>S-2</u>
The following financial statement schedules are included in this report on the pages indicated:	
American Electric Power Company, Inc. (Parent):	
<u>Schedule I – Condensed Financial Information</u>	<u>S-3</u>
<u>Schedule I – Index of Condensed Notes to Condensed Financial Information</u>	<u>S-7</u>
American Electric Power Company, Inc. and Subsidiary Companies:	
<u>Schedule II – Valuation and Qualifying Accounts and Reserves</u>	<u>S-10</u>
Appalachian Power Company and Subsidiaries:	
<u>Schedule II – Valuation and Qualifying Accounts and Reserves</u>	<u>S-10</u>
Indiana Michigan Power Company and Subsidiaries:	
<u>Schedule II – Valuation and Qualifying Accounts and Reserves</u>	<u>S-10</u>
Ohio Power Company and Subsidiaries:	
<u>Schedule II – Valuation and Qualifying Accounts and Reserves</u>	<u>S-11</u>
Public Service Company of Oklahoma:	
<u>Schedule II – Valuation and Qualifying Accounts and Reserves</u>	<u>S-11</u>
Southwestern Electric Power Company Consolidated:	
<u>Schedule II – Valuation and Qualifying Accounts and Reserves</u>	<u>S-11</u>

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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, 2014 and 2013, and for each of the three years in the period ended December 31, 2014, and the Company's internal control over financial reporting as of December 31, 2014, and have issued our reports thereon dated February 20, 2015; such consolidated financial statements and reports are included in the Company's 2014 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 20, 2015

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 subsidiaries, Public Service Company of Oklahoma, and Southwestern Electric Power Company Consolidated (collectively the "Companies") as of December 31, 2014 and 2013, and for each of the three years in the period ended December 31, 2014, and have issued our reports thereon dated February 20, 2015; such financial statements and reports are included in the Companies' 2014 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 20, 2015

SCHEDULE I

AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)

CONDENSED FINANCIAL INFORMATION

CONDENSED STATEMENTS OF INCOME

For the Years Ended December 31, 2014, 2013 and 2012

(in millions, except per-share and share amounts)

	Years Ended December 31,		
	2014	2013	2012
REVENUES			
Affiliated Revenues	\$7	\$4	\$4
EXPENSES			
Other Operation	27	21	22
OPERATING LOSS	(20) (17) (18
Other Income (Expense):			
Interest Income	7	21	22
Interest Expense	(17) (17) (90
LOSS BEFORE EQUITY EARNINGS	(30) (13) (86
Equity Earnings of Unconsolidated Subsidiaries	1,664	1,493	1,345
NET INCOME	1,634	1,480	1,259
Other Comprehensive Income	12	217	133
TOTAL COMPREHENSIVE INCOME	\$1,646	\$1,697	\$1,392
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	488,592,997	486,619,555	484,682,469
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	\$3.34	\$3.04	\$2.60
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	488,899,840	487,040,956	485,084,694
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	\$3.34	\$3.04	\$2.60

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, 2014 and 2013

(in millions)

	December 31,	
	2014	2013
CURRENT ASSETS		
Cash and Cash Equivalents	\$63	\$36
Other Temporary Investments	2	2
Advances to Affiliates	769	539
Accounts Receivable:		
General	8	—
Affiliated Companies	13	11
Total Accounts Receivable	21	11
Prepayments and Other Current Assets	4	6
TOTAL CURRENT ASSETS	859	594
PROPERTY, PLANT AND EQUIPMENT		
General	1	1
Total Property, Plant and Equipment	1	1
Accumulated Depreciation and Amortization	1	1
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	—	—
OTHER NONCURRENT ASSETS		
Investments in Unconsolidated Subsidiaries	17,475	16,353
Affiliated Notes Receivable	45	80
Deferred Charges and Other Noncurrent Assets	57	57
TOTAL OTHER NONCURRENT ASSETS	17,577	16,490
TOTAL ASSETS	\$18,436	\$17,084

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

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SCHEDULE I

AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)

CONDENSED FINANCIAL INFORMATION

CONDENSED BALANCE SHEETS

LIABILITIES AND EQUITY

December 31, 2014 and 2013

(dollars in millions)

	December 31,	
	2014	2013
CURRENT LIABILITIES		
Advances from Affiliates	\$116	\$41
Accounts Payable:		
General	1	—
Affiliated Companies	2	13
Long-term Debt Due Within One Year	3	4
Short-term Debt	602	57
Other Current Liabilities	11	5
TOTAL CURRENT LIABILITIES	735	120
NONCURRENT LIABILITIES		
Long-term Debt	840	836
Deferred Credits and Other Noncurrent Liabilities	41	43
TOTAL NONCURRENT LIABILITIES	881	879
TOTAL LIABILITIES	1,616	999
COMMON SHAREHOLDERS' EQUITY		
Common Stock – Par Value – \$6.50 Per Share:		
	2014	2013
Shares Authorized	600,000,000	600,000,000
Shares Issued	509,739,159	508,113,964
(20,336,592 Shares were Held in Treasury as of December 31, 2014 and 2013)	3,313	3,303
Paid-in Capital	6,204	6,131
Retained Earnings	7,406	6,766
Accumulated Other Comprehensive Income (Loss)	(103) (115
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	16,820	16,085
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$18,436	\$17,084

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, 2014, 2013 and 2012

(in millions)

	Years Ended December 31,		
	2014	2013	2012
OPERATING ACTIVITIES			
Net Income	\$1,634	\$1,480	\$1,259
Adjustments to Reconcile Net Income to Net Cash Flows from from Operating Activities:			
Equity Earnings of Unconsolidated Subsidiaries	(1,664) (1,493) (1,345
Cash Dividends Received from Unconsolidated Subsidiaries	956	1,027	1,294
Change in Other Noncurrent Assets	1	2	13
Change in Other Noncurrent Liabilities	16	16	22
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(10) 96	(47
Accounts Payable	(10) (423) (10
Other Current Liabilities	6	(73) 72
Net Cash Flows from Operating Activities	929	632	1,258
INVESTING ACTIVITIES			
Change in Advances to Affiliates, Net	(230) 111	294
Capital Contributions to Unconsolidated Subsidiaries	(523) (358) (325
Return of Capital Contributions from Unconsolidated Subsidiaries	123	375	—
Repayments of Notes Receivable from Affiliated Companies	35	205	5
Net Cash Flows from (Used for) Investing Activities	(595) 333	(26
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	73	84	83
Issuance of Long-term Debt	—	199	843
Change in Short-term Debt, Net	545	(264) (646
Retirement of Long-term Debt	—	(200) (558
Change in Advances from Affiliates, Net	75	41	—
Dividends Paid on Common Stock	(992) (949) (911
Other Financing Activities	(8) (6) (4
Net Cash Flows Used for Financing Activities	(307) (1,095) (1,193
Net Increase (Decrease) in Cash and Cash Equivalents	27	(130) 39
Cash and Cash Equivalents at Beginning of Period	36	166	127
Cash and Cash Equivalents at End of Period	\$63	\$36	\$166

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
2. Commitments, Guarantees and Contingencies
3. Financing Activities
4. Related Party Transactions

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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, 2014. 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. AEP System's current consolidated federal income tax is allocated to 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 6 in the 2014 Annual Reports.

3. FINANCING ACTIVITIES

The following details long-term debt outstanding as of December 31, 2014 and 2013:

Long-term Debt

Type of Debt and Maturity	Weighted Average Interest Rate as of December 31, 2014	Interest Rate Ranges as of		Outstanding as of	
		December 31, 2014	December 31, 2013	December 31, 2014	December 31, 2013
Senior Unsecured Notes 2017-2022	2.11%	1.65%-2.95%	1.65% - 2.95%	\$ 850	\$ 850
Fair Value of Interest Rate Hedges				(6)	(9)
Unamortized Discount, Net				(1)	(1)
Total Long-term Debt Outstanding				843	840
Long-term Debt Due Within One Year				3	4
Long-term Debt				\$ 840	\$ 836

Long-term debt outstanding as of December 31, 2014 is payable as follows:

	2015	2016	2017	2018	2019	After 2019	Total
	(in millions)						
Principal Amount	\$ 3	\$(15)	\$ 556	\$—	\$—	\$ 300	\$ 844
Unamortized Discount, Net							(1)
Total Long-term Debt Outstanding							\$ 843

Short-term Debt

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

Type of Debt	December 31, 2014	Weighted Average Interest Rate	2013	Weighted Average Interest Rate	
	Outstanding Amount (in millions)		Outstanding Amount (in millions)		
Commercial Paper	\$602	0.59	% \$57	0.29	%
Total Short-term Debt	\$602		\$57		

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 \$413 thousand, \$7 thousand and \$11 thousand for the years ended December 31, 2014, 2013 and 2012, 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 \$4 million, \$4 million and \$5 million for the years ended December 31, 2014, 2013 and 2012, 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 \$3 million, \$15 million and \$15 million for the years ended December 31, 2014, 2013 and 2012, respectively.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

AEP					
Description	Balance at Beginning of Period (in millions)	Additions Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2014	\$60	\$51	\$9	\$99	\$21
Year Ended December 31, 2013	36	51	21	48	60
Year Ended December 31, 2012	32	53	3	52	36

(a) Recoveries offset by reclasses to other assets and liabilities.

(b) Uncollectible accounts written off.

APCo					
Description	Balance at Beginning of Period (in thousands)	Additions Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2014	\$2,443	\$8,965	\$2,526	\$11,570	\$2,364
Year Ended December 31, 2013	6,087	4,737	1,768	10,149	2,443
Year Ended December 31, 2012	5,289	15,652	1,689	16,543	6,087

(a) Recoveries offset by reclasses to other assets and liabilities.

(b) Uncollectible accounts written off.

I&M					
Description	Balance at Beginning of Period (in thousands)	Additions Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2014	\$184	\$152	\$211	\$53	\$494
Year Ended December 31, 2013	229	(40)	(c) —	5	184
Year Ended December 31, 2012	1,750	20	—	1,541	229

(a) Recoveries offset by reclasses to other assets and liabilities.

(b) Uncollectible accounts written off.

(c) Recoveries on previous reserve balance.

OPCo		Additions				
Description	Balance at	Charged	Charged	Deductions	Distribution	Balance
	Beginning	to	to Other	(b)	of OPCo	at
	of Period	Costs and	Accounts		Generation	End of
	(in thousands)	Expenses	(a)		to Parent	Period
Deducted from Assets:						
Accumulated Provision for						
Uncollectible						
Accounts:						
Year Ended December 31, 2014	\$34,984	\$1,236	\$8,012	\$44,061	\$—	\$171
Year Ended December 31, 2013	129	15,722	19,191	51	(7) 34,984
Year Ended December 31, 2012	3,563	(9) (c) 43	3,468	—	129

(a) Recoveries offset by reclasses to other assets and liabilities.

(b) Uncollectible accounts written off.

(c) Recoveries on previous reserve balance.

PSO		Additions				
Description	Balance at	Charged to	Charged to	Deductions (b)	Balance at	
	Beginning	Costs and	Other		End of	
	of Period	Expenses	Accounts (a)		Period	
	(in thousands)					
Deducted from Assets:						
Accumulated Provision for						
Uncollectible						
Accounts:						
Year Ended December 31, 2014	\$462	\$(273) (c) \$—	\$42		\$147
Year Ended December 31, 2013	872	(122) (c) —	288		462
Year Ended December 31, 2012	777	95	—	—		872

(a) Recoveries offset by reclasses to other assets and liabilities.

(b) Uncollectible accounts written off.

(c) Recoveries on previous reserve balance.

SWEPCo		Additions				
Description	Balance at	Charged to	Charged to	Deductions (b)	Balance at	
	Beginning	Costs and	Other		End of	
	of Period	Expenses	Accounts (a)		Period	
	(in thousands)					
Deducted from Assets:						
Accumulated Provision for						
Uncollectible						
Accounts:						
Year Ended December 31, 2014	\$1,418	\$452	\$(1,353) (c) \$1		\$516
Year Ended December 31, 2013	2,041	(143) (c) 2	482		1,418
Year Ended December 31, 2012	989	71	981	—		2,041

(a) Recoveries offset by reclasses to other assets and liabilities.

(b) Uncollectible accounts written off.

(c) Recoveries on previous reserve balance.

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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) Registration Statement No. 333-200956, Ex 4(b)
*4(b)	\$1.75 Billion Second Amended and Restated Credit Agreement, dated as of November 10, 2014, among AEP, the banks, financial institutions and other institutional lenders listed on the signature pages thereof, and Barclays Bank PLC, as Administrative Agent.	
*4(c)	\$1.75 Billion Third Amended and Restated Credit Agreement, dated as of November 10, 2014, among AEP, the banks, financial institutions and other institutional lenders listed on the signature pages thereof, and JPMorgan Chase Bank, N.A. as Administrative Agent.	
4(d)	\$1 Billion Term Credit Agreement, dated as of July 17, 2013, among AEP, APCo, OPCo, AEP Generation Resources Inc., the banks, financial institutions and other institutional lenders listed on the signature pages thereof, and Wells Fargo Bank, National Association, as Administrative Agent.	Form 10-Q, Ex 4, June 30, 2013
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) | Transmission Agreement, effective November 2010, among APCo, CSPCo, I&M, KGPCo, KPCo, OPCo and WPCo with AEPSC as agent. | 2013 Form 10-K, Ex 10(c) |
| 10(c) | Transmission Coordination Agreement dated January 1, 1997, restated and amended by and among PSO, SWEPCo and AEPSC. | 2009 Form 10-K, Ex 10(d) |
| 10(d) | 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(d)(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) |

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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(e)(3)
10(e)	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(f)	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(1)
10(g)	Consent Decree with U.S. District Court dated October 9, 2007, as modified.	Form 8-K, Ex 10.1 dated October 9, 2007 Form 10-Q, Ex 10, June 30, 2013
†10(h)	AEP Accident Coverage Insurance Plan for Directors.	1985 Form 10-K, Ex 10(g)
†10(i)	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(j)	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(k)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(l)(1)(A)
†10(k)(1)	Guaranty by AEP of AEPSC Excess Benefits Plan.	1990 Form 10-K, Ex 10(h)(1)(B)
†10(l)	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)(1)(A)	Amendment to AEP System Supplemental Retirement Savings Plan, as Amended and Restated as of January 1, 2011 (Non-Qualified).	
†10(m)	AEPSC Umbrella Trust for Executives.	1993 Form 10-K, Ex 10(g)(3)

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†10(m)(1)(A)	First Amendment to AEPSC Umbrella Trust for Executives.	2008 Form 10-K, Ex 10(l)(3)(A)
†10(n)	Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.	2002 Form 10-K, Ex 10(m)(4)
†10(n)(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(o)	AEP System Senior Officer Annual Incentive Compensation Plan amended and restated as of February 28, 2012.	Form 10-Q, Ex 10, June 30, 2012
†10(p)	AEP System Survivor Benefit Plan, effective January 27, 1998.	Form 10-Q, Ex 10, September 30, 1998
†10(p)(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(p)(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)

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Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
†10(q)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(p)
†10(q)(1)(A)	First Amendment to AEP System Incentive Compensation Deferral Plan as Amended and Restated as of January 1, 2008.	2011 Form 10-K, Ex 10(p)(1)(A)
*†10(q)(2)(A)	Second Amendment to AEP System Incentive Compensation Deferral Plan as Amended and Restated as of January 1, 2008.	
*†10(r)	AEP Change In Control Agreement, as Revised Effective January 1, 2015.	
†10(s)	Amended and Restated AEP System Long-Term Incentive Plan as of September 25, 2012.	Form 10-Q, Ex 10, September 30, 2012
†10(s)(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(s)(2)(A)	Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan Amended and Restated effective January 1, 2013.	2012 Form 10-K, Ex 10 (t)(2)(A)
†10(t)	AEP System Stock Ownership Requirement Plan Amended and Restated effective January 1, 2014.	Form 10-Q, Ex 10, June 30, 2014
*†10(t)(1)(A)	First Amendment to AEP System Stock Ownership Requirement Plan as Amended and Restated effective January 1, 2014.	
†10(u)	Central and South West System Special Executive Retirement Plan Amended and Restated effective January 1, 2009.	2008 Form 10-K, Ex 10(v)
†10(v)	AEP Executive Severance Plan effective January 1, 2014.	Form 8-K, Ex 10.1 dated January 15, 2014
†10(w)	Letter Agreement dated November 20, 2012 between AEPSC and Lana Hillebrand	2013 Form 10-K, Ex 10(s)
*12	Statement re: Computation of Ratios.	

- *13 Copy of those portions of the AEP 2014 Annual Report (for the fiscal year ended December 31, 2014) 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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Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
101.INS	XBRL Instance Document.	
101.SCH	XBRL Taxonomy Extension Schema.	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
APCo‡ File No. 1-3457		
2(a)	Agreement and Plan of Merger dated as of December 31, 2013 by and between Newco Appalachian Inc. and Appalachian Power Company.	Form 8-K, Ex 2.1 dated December 31, 2013
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) Registration Statement No. 333-200750, Ex. 4(b)(c)

4(b)	\$1 Billion Term Credit Agreement, dated as of July 17, 2013, among AEP, APCo, OPCo, AEP Generation Resources Inc., the banks, financial institutions and other institutional lenders listed on the signature pages thereof, and Wells Fargo Bank, National Association, as Administrative Agent.	Form 10Q, Ex 4, June 30, 2013
10(a)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended September 10, 2010.	2013 Form 10-K, Ex 10(a)
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, effective November 2010, among APCo, CSPCo, I&M, KGPCo, KPCo, OPCo and WPCo with AEPSC as agent.	2013 Form 10-K, Ex 10(c)
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)

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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, as modified	Form 8-K, Ex 10.1 dated October 9, 2007 Form 10-Q, Ex 10, June 30, 2013
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the APCo 2014 Annual Report (for the fiscal year ended December 31, 2014) which are incorporated by reference in this filing.	
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
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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.

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)

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)

4(b) Company Order and Officers Certificate to The Bank of New York Mellon dated March 18, 2013 of 3.20% Series J due 2023. Form 8-K, Ex 4(a) dated March 18, 2013

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Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
10(a)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended September 10, 2010.	2013 Form 10-K, Ex 10(a)
10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M, and OPCo and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a) Registration Statement No. 2-61009, Ex 5(b) 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525
10(b)(1)	Unit Power Agreement dated as of March 31, 1982 between AEGCo and I&M, as amended.	Registration Statement No. 33-32752, Ex 28(b)(1)(A)(B)
10(c)	Transmission Agreement, effective November 2010, among APCo, CSPCo, I&M, KGPCo, KPCo, OPCo and WPCo with AEPSC as agent.	2013 Form 10-K, Ex 10(c)
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)
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, as modified.	Form 8-K, Ex 10.1 dated October 9, 2007 Form 10-Q, Ex 10, June 30, 2013
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 2014 Annual Report (for the fiscal year ended December 31, 2014) 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.

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Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
OPCo‡ File No.1-6543		
2(a)	Asset Contribution Agreement effective as of December 31, 2013 by and between Ohio Power Company and AEP Generation Resources Inc.	Form 8-K, Ex 2.1 dated December 31, 2013
2(b)	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
3(a)	Composite of the Amended Articles of Incorporation of OPCo, dated June 3, 2002.	Form 10-Q, Ex 3(e), June 30, 2002
3(b)	Amended Code of Regulations of OPCo.	Form 10-Q, Ex 3(b), June 30, 2008
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)		

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- Indenture (for unsecured debt securities), dated as of September 1, 1997, between CSPCo (predecessor in interest to OPCo) and Bankers Trust Company, as Trustee. Registration Statement No. 333-54025, Ex 4(a)(b)(c)(d)
Registration Statement No. 333-128174, Ex 4(b)(c)(d)
Registration Statement No. 333-150603. Ex 4(b)
- 4(e) Indenture (for unsecured debt securities), dated as of February 1, 2003, between CSPCo (predecessor in interest to OPCo) and Bank One, N.A., as Trustee. Registration Statement No. 333-128174, Ex 4(e)(f)(g)
Registration Statement No. 333-150603 Ex 4(b)
- 4(f) First Supplemental Indenture, dated as of December 31, 2012, by and between OPCo and Deutsche Bank Trust Company Americas, as trustee, supplementing the Indenture dated as of September 1, 1997 between CSPCo (predecessor in interest to OPCo) and the trustee. Form 8-K, Ex 4.1 dated January 6, 2012
- 4(g) Third Supplemental Indenture, dated as of December 31, 2012, by and between OPCo and The Bank of New York Mellon Trust Company, N.A., as trustee, supplementing the Indenture dated as of February 14, 2003 between CSPCo (predecessor in interest to OPCo) and the trustee. Form 8-K, Ex 4.2 dated January 6, 2012
- 4(h) CSPCo (predecessor in interest to OPCo) Company Order and Officer's Certificate to Deutsche Bank Trust Company Americas, dated May 16, 2008, establishing terms of 6.05% Senior Notes, Series G, due 2018. Form 8-K, Ex 4(a), dated May 16, 2008

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Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(i)	\$1 Billion Term Credit Agreement, dated as of July 17, 2013, among AEP, APCo, OPCo, AEP Generation Resources Inc., the banks, financial institutions and other institutional lenders listed on the signature pages thereof, and Wells Fargo Bank, National Association, as Administrative Agent.	Form 10Q, Ex 4, June 30, 2013
10(a)	Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended September 10, 2010.	2013 Form 10-K, Ex 10(a)
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, effective November 2010, among APCo, CSPCo, I&M, KGPCo, KPCo, OPCo and WPCo with AEPSC as agent.	2013 Form 10-K, Ex 10(a)
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(e)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(d)(2)
10(f)	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(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), File No. 1-3525
10(h)	Consent Decree with U.S. District Court, as modified.	Form 8-K, Item Ex 10.1 dated October 9, 2007 Form 10-Q, Ex 10, June 30, 2013
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the OPCo 2014 Annual Report (for the fiscal year ended December 31, 2014) which are incorporated by reference in this	

filing.

- *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.

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Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
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)
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)	Third Restated and Amended Transmission Coordination Agreement Between PSO, SWEPCo and AEPSC dated February 18, 2011.	2012 Form 10-K, Ex 10(b)
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the PSO 2014 Annual Report (for the fiscal year ended December 31, 2014) which are incorporated by reference in this filing.	
*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.

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Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
SWEPCo‡	File No. 1-3146	
3(a)	Composite of Amended Restated Certificate of Incorporation of SWEPCo.	2008 Form 10-K, Ex 3(a)
3(b)	Composite By-Laws of SWEPCo amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)
4(a)	Indenture (for unsecured debt securities), dated as of February 4, 2000, between SWEPCo and The Bank of New York, as Trustee.	Registration Statement No. 333-96213 Registration Statement No. 333-87834, Ex 4(a)(b) Registration Statement No. 333-100632, Ex 4(b) Registration Statement No. 333-108045, Ex 4(b) Registration Statement No. 333-145669, Ex 4(c)(d) Registration Statement No. 333-161539, Ex 4(b)(c) Registration Statement No. 333-194991, Ex 4(b)(c)
10(a)	Third Restated and Amended Transmission Coordination Agreement Between PSO, SWEPCo and AEPSC dated February 18, 2011.	2012 Form 10-K, Ex 10(b)
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the SWEPCo 2014 Annual Report (for the fiscal year ended December 31, 2014) which are incorporated by reference in this filing.	
*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.

‡ 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.

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