AMERICAN ELECTRIC POWER CO INC
Form 10-K
February 24, 2016

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

FORM 10-K

(Mark One)

x	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
	For the fiscal year ended December 31, 2015
o	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
	For the transition period from __________ to_________

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

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

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

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

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

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

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

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

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

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, 2015 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, 2015
American Electric Power Company, Inc.	$26,011,055,215	491,052,581 ($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, 2015: 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 2016 Annual Meeting of Shareholders.	Part III

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

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

TABLE OF CONTENTS

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States.
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 interest in ETT.
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 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.
CAA	Clean Air Act.
Clean Power Plan	Guidelines regulating CO2 emissions from existing sources published by Federal EPA in October 2015; its implementation was stayed by the U.S. Supreme Court in February 2016.
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.
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.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between Parent 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	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IMTCo	AEP Indiana Michigan Transmission Company, Inc.
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.
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.

i

Term	Meaning
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.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants: APCo, I&M, OPCo, PSO and SWEPCo.
Registrants	SEC registrants: AEP, APCo, I&M, OPCo, PSO and SWEPCo.
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, 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 the Registrants 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, 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, management undertakes 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 AEP service territories.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability or cost of capital to finance new capital projects and refinance existing debt.
- 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 the ability to recover significant storm restoration costs.
- The cost of fuel and its transportation and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generation capacity and the performance of generation plants.
- The ability to recover fuel and other energy costs through regulated or competitive electric rates.
- The ability to build transmission lines and facilities (including the 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 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.
- The ability to constrain operation and maintenance costs.
- The 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 generated and sold at wholesale.
- Changes in technology, particularly with respect to new, developing, alternative or distributed sources of generation.
- The 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 market for generation in Ohio and PJM and the ability to recover investments in Ohio generation assets.
The ability to successfully and profitably manage competitive generation assets, including the evaluation of strategic alternatives for these assets as some of the alternatives could result in a loss.

Changes in the creditworthiness of the counterparties with contractual arrangements, including participants in the energy trading market.
Actions of rating agencies, including changes in the ratings of debt.
The impact of volatility in the capital markets on the value of the investments held by the 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 the Registrants speak only as of the date of this report or as of the date they are made. The Registrants 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.

Investors should note that the Registrants announce material financial information in SEC filings, press releases and public conference calls. Based on guidance from the SEC, the Registrants may use the Investors section of AEP's website (www.aep.com) to communicate with investors about the Registrants. It is possible that the financial and other information posted there could be deemed to be material information. The information on AEP's website is not part 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. 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 affiliates.

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, 2015, the subsidiaries of AEP had a total of 17,405 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 957,000 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 6,650 MW of generating capacity. APCo uses its generation to serve its retail and other customers. As of December 31, 2015, APCo had 1,836 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 3,523 MW of generating capacity, which it uses to serve its retail and other customers. As of December 31, 2015, I&M had 2,489 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 170,000 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 1,058 MW of generating capacity. KPCo uses its generation to serve its retail and other customers. As of December 31, 2015, KPCo had 558 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, 2015, KGPCo had 52 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 1,468,000 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, 2015, OPCo had 1,552 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 545,000 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 4,432 MW of generating capacity, which it uses to serve its retail and other customers. As of December 31, 2015, PSO had 1,134 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 531,000 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 5,798 MW of generating capacity, which it uses to serve its retail and other customers. As of December 31, 2015, SWEPCo had 1,483 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 826,000 retail customers through REPs in southern Texas. As of December 31, 2015, TCC had 1,085 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, 2015, TNC had 346 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. 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, 2015, WPCo had 56 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. AEGCo has granted AGR the rights to the power generated at the Lawrenceburg facility, a 1,186 MW natural gas-fired generating unit, pursuant to a unit power agreement through 2017. As of December 31, 2015, AEGCo had 73 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 supplied capacity for OPCo's switched and non-switched retail load for the period January 1, 2014 through May 31, 2015. AGR owns 6,752 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, 2015, AGR had 857 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 AEP's existing utility operating companies. The transmission companies develop and own new transmission assets that are physically connected to the AEP 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 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 its subsidiaries have any employees. Instead, AEPSC and certain AEP utility subsidiaries provide the services required by these entities. AEPTCo is part of the AEP Transmission Holdco segment.

3

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 AEP subsidiaries. The executive officers of AEP and certain of its public utility subsidiaries are employees of AEPSC. As of December 31, 2015, AEPSC had 5,622 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	24%	OPCo	10.20%
Texas	14%	TCC	9.96%
		TNC	9.96%
		SWEPCo	9.65%
Virginia	12%	APCo	9.70%
West Virginia	12%	APCo	9.75%
		WPCo	9.75%
Oklahoma	11%	PSO	9.85%
Indiana	11%	I&M	10.20%
Louisiana	5%	SWEPCo	10.00%
Kentucky	5%	KPCo	10.25%
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, 2015.

(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, 2015, 2014 and 2013 are as follows:

Description	Years Ended December 31, 2015	2014	2013
	(in millions)		
Vertically Integrated Utilities Segment			
Retail Revenues			
Residential Sales	$3,295.4	$3,328.5	$3,216.4
Commercial Sales	2,057.7	2,032.7	2,002.4
Industrial Sales	2,096.9	2,124.5	2,028.7
PJM Net Charges	(0.7)	(61.8)	9.3
Provision for Rate Refund	61.5	(1.7)	(15.6)
Other Retail Sales	177.4	181.9	172.4
Total Retail Revenues	7,688.2	7,604.1	7,413.6
Wholesale Revenues			
Off-System Sales	1,051.2	1,529.9	1,670.9
Transmission	192.2	113.4	132.7
Total Wholesale Revenues	1,243.4	1,643.3	1,803.6
Other Electric Revenues	110.4	124.7	89.7
Other Operating Revenues	27.9	24.7	39.7
Sales to Affiliates	102.3	87.6	645.9
Total Revenues Vertically Integrated Utilities Segment	$9,172.2	$9,484.4	$9,992.5
Transmission and Distribution Utilities Segment			
Retail Revenues			
Residential Sales	$2,213.1	$2,313.1	$2,164.5
Commercial Sales	1,170.0	1,178.4	1,161.1
Industrial Sales	512.5	502.7	549.0
PJM Net Charges	—	47.5	21.3
Provision for Rate Refund	—	(11.9)	22.1
Other Retail Sales	37.7	39.6	38.8
Total Retail Revenues	3,933.3	4,069.4	3,956.8
Wholesale Revenues			
Off-System Sales	106.1	143.0	30.8
Transmission	286.0	277.7	227.7
Total Wholesale Revenues	392.1	420.7	258.5
Other Electric Revenues	52.7	51.5	56.1
Other Operating Revenues	13.9	11.0	7.7
Sales to Affiliates	164.6	261.0	199.3
Total Revenues Transmission and Distribution Utilities Segment	$4,556.6	$4,813.6	$4,478.4
AEP Transmission Holdco Segment			
Transmission Revenues	$100.3	$73.9	$26.8
Other Operating Revenues	0.3	—	—
Sales to Affiliates	228.6	118.0	50.9
Total Revenues AEP Transmission Holdco Segment	$329.2	$191.9	$77.7

Generation & Marketing Segment			
Generation Revenues			
Affiliated	$484.9	$1,306.5	$2,457.1
Nonaffiliated	1,544.5	1,396.9	314.4
Trading, Marketing and Retail Revenues			
Affiliated	61.1	158.8	0.1
Nonaffiliated	1,299.8	961.9	868.1
Wind Generation Revenues			
Nonaffiliated	22.4	25.5	25.5
Total Revenues Generation & Marketing Segment	$3,412.7	$3,849.6	$3,665.2

APCo

Description	Years Ended December 31, 2015	2014	2013
	(in millions)		
Retail Revenues			
Residential Sales	$1,228.3	$1,257.3	$1,219.7
Commercial Sales	584.6	585.9	583.8
Industrial Sales	657.1	690.4	697.0
PJM Net Charges	(0.2)	13.5	5.0
Provision for Rate Refund	25.2	(6.1)	—
Other Retail Sales	79.4	82.5	77.2
Total Retail Revenues	2,574.4	2,623.5	2,582.7
Wholesale Revenues			
Off-System Sales	136.0	191.2	433.6
Transmission	53.5	26.9	21.0
Total Wholesale Revenues	189.5	218.1	454.6
Other Electric Revenues	41.7	57.8	22.3
Total Electric Generation, Transmission and Distribution Revenues	2,805.6	2,899.4	3,059.6
Sales to Affiliates	147.8	144.5	347.5
Other Revenues	10.1	9.2	10.3
Total Revenues	$2,963.5	$3,053.1	$3,417.4

I&M

Description	Years Ended December 31, 2015	2014	2013
	(in millions)		
Retail Revenues			
Residential Sales	$591.0	$588.4	$565.8
Commercial Sales	416.7	390.4	400.8
Industrial Sales	482.4	463.0	455.1
PJM Net Charges	0.2	(60.9)	3.3
Provision for Rate Refund	—	(0.6)	—
Other Retail Sales	7.0	6.9	7.0
Total Retail Revenues	1,497.3	1,387.2	1,432.0
Wholesale Revenues			
Off-System Sales	534.7	759.5	571.8
Transmission	25.2	(9.4)	4.1
Total Wholesale Revenues	559.9	750.1	575.9
Other Electric Revenues	16.1	11.8	14.4
Total Electric Generation, Transmission and Distribution Revenues	2,073.3	2,149.1	2,022.3
Sales to Affiliates	106.2	98.6	341.7
Other Revenues	6.7	2.0	2.9
Total Revenues	$2,186.2	$2,249.7	$2,366.9

OPCo

Description	Years Ended December 31, 2015	2014	2013

	(in millions)		
Retail Revenues			
Residential Sales	$1,660.0	$1,768.1	$1,676.1
Commercial Sales	725.2	732.2	763.8
Industrial Sales	405.9	405.8	468.4
PJM Net Charges	—	47.5	6.9
Provision for Rate Refund	—	(11.9)	22.1
Other Retail Sales	13.3	14.9	15.9
Total Retail Revenues	2,804.4	2,956.6	2,953.2
Wholesale Revenues			
Off-System Sales	156.1	143.0	563.0
Transmission	63.2	78.5	17.7
Total Wholesale Revenues	219.3	221.5	580.7
Other Electric Revenues	32.4	26.8	28.3
Total Electric Generation, Transmission and Distribution Revenues	3,056.1	3,204.9	3,562.2
Sales to Affiliates	84.1	165.2	1,185.0
Other Revenues	8.5	6.8	15.4
Total Revenues	$3,148.7	$3,376.9	$4,762.6

PSO

Description	Years Ended December 31, 2015	2014	2013
	(in millions)		
Retail Revenues			
Residential Sales	$554.5	$561.2	$530.5
Commercial Sales	372.4	375.5	351.5
Industrial Sales	263.1	260.4	234.1
Other Retail Sales	76.7	78.7	73.6
Total Retail Revenues	1,266.7	1,275.8	1,189.7
Wholesale Revenues			
Off-System Sales	11.5	13.8	34.6
Transmission	38.6	36.5	36.4
Total Wholesale Revenues	50.1	50.3	71.0
Other Electric Revenues	14.6	14.2	17.0
Total Electric Generation, Transmission and Distribution Revenues	1,331.4	1,340.3	1,277.7
Sales to Affiliates	4.6	7.1	14.2
Other Revenues	3.2	4.2	3.6
Total Revenues	$1,339.2	$1,351.6	$1,295.5

SWEPCo

Description	Year Ended December 31, 2015	2014	2013
	(in millions)		
Retail Revenues			
Residential Sales	$593.5	$580.4	$586.5
Commercial Sales	471.5	457.2	472.3
Industrial Sales	318.8	348.9	316.3
Provision for Rate Refund	36.3	5.0	(16.1)
Other Retail Sales	8.2	8.3	8.3
Total Retail Revenues	1,428.3	1,399.8	1,367.3
Wholesale Revenues			
Off-System Sales	252.7	339.3	294.6
Transmission	60.2	55.1	59.1
Total Wholesale Revenues	312.9	394.4	353.7
Other Electric Revenues	21.1	23.7	21.6
Total Electric Generation, Transmission and Distribution Revenues	1,762.3	1,817.9	1,742.6
Sales to Affiliates	16.6	26.3	51.8
Other Revenues	2.0	2.2	1.4
Total Revenues	$1,780.9	$1,846.4	$1,795.8

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 2015 Annual Reports, under the heading entitled Financial Condition for additional information concerning short-term funding and 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 its 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, 2015, 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 2015 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 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 management believes are potentially material to the AEP System are outlined below.

Clean Water Act Requirements

Operations for AEP subsidiaries 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 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.

In November 2015, the Federal EPA issued a final rule 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. For additional information, see Management's Discussion and Analysis of Financial Condition and Results of Operations under the headings entitled Environmental Issues.

Coal Ash Regulation

AEP's operations produce a number of different coal combustion products, including fly ash, bottom ash, gypsum and other materials. Effective October 2015, the Federal EPA adopted 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. 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 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 AEP’s power plants are described below. The states implement and administer many of these programs and could impose additional or more stringent requirements.

AEP has made significant long-term investments in environmental controls to reduce air emissions from its power plants. Between 2000 and 2015, AEP invested approximately $8.1 billion in environmental controls, primarily related to CAA, that have significantly reduced emissions. During the same time period and including our projections through 2017, AEP expects its emissions of mercury to have been reduced by approximately 85%. Since 1990 and including our projections through 2017, AEP expects its emissions of SO_2 and NO_x to have been reduced by approximately 90% and 85% respectively.

The Acid Rain Program

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

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

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 lowered the annual standard. A new ozone standard was adopted in 2015. The Federal EPA also adopted a new short-term standard for SO_2 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 SO_2, $PM_{2.5}$ and ozone standards, which could result in more stringent emission limitations being imposed on AEP facilities.

In 2005, the Federal EPA issued the Clean Air Interstate Rule (CAIR), which required additional reductions in SO_2 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 SO_2 and NO_x emissions from fossil fuel-fired electric generating units in 27 states and the District of Columbia. Petitions for review were filed with the U.S. Court of Appeals for the District of Columbia Circuit, and CSAPR was vacated. 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 the court has remanded certain state budgets to Federal EPA for further rulemaking while the rule remains in effect. Federal EPA has proposed more stringent NO_x budgets for 23 states during the 2017 ozone season. For additional information regarding CSAPR, see Management's Discussion and Analysis of Financial Condition and Results of Operations under the headings entitled Environmental Issues-Clean Air Act Requirements.

Hazardous Air Pollutants

As a result of the 1990 Amendments to the CAA, the Federal EPA investigated hazardous air pollutant (HAP) emissions from the electric utility sector and submitted a report to Congress, identifying mercury emissions from coal-fired power plants as warranting further study. In 2011, the Federal EPA issued a final rule setting Maximum Achievable Control Technology (MACT) standards for new and existing coal and oil-fired utility units and New Source Performance Standards (NSPS) for emissions from new and modified power plants. 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 determined that Federal EPA acted unreasonably in refusing to consider costs in determining if it was appropriate and necessary to regulate hazardous air pollutant emissions from electric generating units. Federal EPA has issued a supplemental finding and the rule remains in effect. 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 issued a proposed 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

AEP has taken action to reduce and offset CO_2 emissions from its generating fleet and expects CO_2 emissions from its operations to continue to decline due to the retirement of some of its coal-fired generation units, and actions taken to diversify the generation fleet and increase energy efficiency where there is regulatory support for such activities. AEP's total CO_2 emissions in 2015 (not including emissions from the Kyger Creek and Clifty Creek Plants) were approximately 102.4 million metric tons, a 30% reduction from AEP's 2005 CO_2 emissions of approximately 146 million metric tons. Federal EPA has taken action to regulate CO_2 emissions from new and existing fossil fueled electric generating units under the existing provisions of the CAA. For example, the Federal EPA published the Clean Power Plan in October 2015. Such actions, including the Clean Power Plan, are being legally challenged by numerous parties and final regulatory outcomes remain uncertain. In February 2016, the U.S. Supreme Court issued a stay on the final Clean Power Plan, including all of the deadlines for submission of initial or final state plans. The stay will remain in effect until a final decision is issued by the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court considers any petition for review. For additional information regarding the Federal EPA action taken to regulate CO_2 emissions, including the Clean Power Plan, see Management's Discussion and Analysis of Financial Condition and Results of Operations under the headings entitled Environmental Issues-Climate Change, CO_2 Regulation and Energy Policy.

Management expects emissions to continue to decline over time as AEP diversifies generating sources and operates 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. Management's strategy for this transformation includes diversifying AEP's fuel portfolio and generating more electricity from natural gas, increasing energy efficiency and investing in renewable resources, where there is regulatory support.

AEP's fossil fuel-fired generating units are large sources of CO_2 emissions. If substantial additional CO_2 emission reductions are required, there will be significant increases in capital expenditures and operating costs which would hasten the ultimate retirement of older, less-efficient, coal-fired units. To the extent additional investments are made to reduce CO_2 emissions and receive regulatory approvals to increase rates, return on capital investment would have a positive effect on future earnings. Prudently incurred capital investments made by AEP 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. Management would expect these principles to apply to investments made to address new environmental requirements. However, requests for rate increases reflecting these costs can have adverse effects because regulators could limit the amount or timing of increased costs that AEP would recover through higher rates. For sales of energy into competitive markets, however, there is no such recovery mechanism.

Renewable Sources of Energy

All of the states AEP serves (other than Kentucky and Tennessee) have established mandatory or voluntary programs to increase the use of energy efficiency, alternative energy, or renewable energy sources.

At the end of 2015, the AEP operating companies had long-term contracts for 2,031.5 MW of wind and 10.1 MW of solar power delivering renewable energy to the companies' customers. In addition, I&M began construction on the first of four solar projects that will make up I&M's 14.7 MW Clean Energy Solar Pilot Project (CESPP) that was approved by the Indiana Utility Regulatory Commission. 599 MWs of recently-completed wind projects under contract for PSO were in service as of late 2015, and the remaining three projects associated with I&M's CESPP projects are expected to begin deliveries in 2016. This will result in a total of 2,655.3 MW of wind and solar in-service for AEP. Management actively manages AEP's compliance position and is on pace to meet the relevant requirements or benchmarks in each applicable jurisdiction.

The growth of AEP's renewable portfolio reflects the company's strategy to diversify its generation resources to provide clean energy options to customers that meet both energy and capacity needs. In addition to gradually reducing AEP's reliance on coal-fueled generating units, the growth of renewables and natural gas helps AEP to maintain a diversity of generation resources.

The Clean Power Plan effectively establishes a renewable portfolio standard for each of AEP's states, creating additional opportunities for renewable growth. Independent of the Clean Power Plan, the integrated resource plans filed with state regulatory commissions by AEP's regulated utility subsidiaries reflect AEP's renewable strategy to balance reliability and cost with customers' desire for clean energy in a carbon-constrained world. The Company has committed significant capital investments to modernize the electric grid and integrate these new resources. Transmission assets of the AEP System interconnect approximately 7,500 MW of renewable energy resources of third parties, and AEP's transmission development initiatives are designed to facilitate the interconnection of additional renewable energy resources.

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 AEP serves. For the period 2008 through 2015, these programs have reduced annual consumption by over 6.0 million megawatt hours and peak demand by over 1,500 MW. AEP estimates that its operating companies spent approximately $875 million during that period to achieve these levels.

Energy efficiency and demand reduction programs have received regulatory support in most of the states AEP serves, and appropriate cost recovery will be essential for AEP operating companies 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. The Clean Power Plan could provide additional opportunities for energy efficiency if states develop implementation plans that require energy efficiency. AEP believes its experience providing robust energy efficiency programs in several states positions the company to be a cost-effective provider of these programs as states develop their implementation plans.

AEP is also developing and marketing a merchant distributed resource portfolio. AEP’s newly-formed subsidiary, OnSite Partners LLC, works directly with wholesale and large retail customers to provide tailored solutions based upon market knowledge, technology innovations and deal structuring which may include distributed solar, wind, combined heat and power, energy storage, waste heat recovery, energy efficiency, peaking generation and other forms of cost reducing energy technologies. OnSite Partners LLC pursues projects where a suitably termed power agreement is entered into with a credit-worthy counterparty.

Corporate Governance

In response to environmental issues and in connection with its assessment of AEP’s strategic plan, the Board of Directors continually reviews the risks posed by new environmental rules and requirements such as the Clean Power Plan that could accelerate the retirement of coal-fired generation assets. The Board of Directors is informed of any new environmental regulations and proposed regulation or legislation that would 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 financial statements entitled Commitments, Guarantees and Contingencies, included in the 2015 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 2013, 2014 and 2015 and the current estimate for 2016 are shown below. AFUDC debt is included in the historical periods. These investments include both environmental as well as other related spending. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends 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 2015 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. These estimates do not include any projected costs that might be triggered by compliance with the Clean Power Plan. The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the AEP System. AEP typically recovers costs of complying with environmental standards from customers through rates in regulated jurisdictions. For AEP's merchant generation units however, there is no such recovery mechanism. Failure to recover these costs could reduce future net income and cash flows and possibly harm AEP's 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 financial statements, entitled Commitments, Guarantees and Contingencies, included in the 2015 Annual Reports, for more information regarding environmental expenditures in general.

Historical and Projected Environmental Investments

	2013 Actual	2014 Actual	2015 Actual	2016 Estimate
	(in millions)			
Total AEP (a)	$424.2	$539.8	$599.4	$353.2
APCo (b)	44.8	31.3	78.4	58.3
I&M	28.3	51.4	45.6	60.8
OPCo (c)	129.3	—	—	—
PSO	56.1	72.1	92.3	29.4
SWEPCo	135.7	225.3	243.8	86.3

(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) For APCo, the projected environmental investments above include the conversions of 470 MWs of coal generation to natural gas. If natural gas conversion is not completed, the units could be retired sooner than planned.

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

Management continues to refine the cost estimates of complying with air and water quality standards and other impacts of the environmental proposals. The following cost estimates for periods following 2016 will change depending on the timing of implementation and whether the Federal EPA provides flexibility in the final rules. These cost estimates will also change based on: (a) the states' implementation of these regulatory programs, including the potential for state implementation plans (SIPs) or federal implementation plans (FIPs) that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on the units, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired, replaced or sold, including the type and amount of such replacement capacity and (g) other factors. The following cost estimates do not include any projected costs that might be triggered by compliance with the Clean Power Plan and are limited to only the costs of major projects to comply with existing air and water quality standards. In addition, management is continuing to evaluate the economic feasibility of environmental investments on both regulated and nonregulated plants.

For the Registrant Subsidiaries, management's current ranges of estimates of environmental investments beginning in 2017, exclusive of debt AFUDC, are set forth below:

Projected (2017 - 2025) Environmental Investment Company	Low	High
	(in millions)	
APCo	$245	$295
I&M	215	265
PSO	15	35
SWEPCo	195	240

BUSINESS SEGMENTS

AEP's reportable segments and their related business activities are outlined below. See Note 9 to the financial statements entitled Business Segments, included in the 2015 Annual Reports, for additional information on the 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 standard service offer customers and provides transmission and distribution services for all connected load.

AEP Transmission Holdco

- Development, construction and operation of transmission facilities through investments in AEP's 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, SPP and MISO.

AEP River Operations

- Commercial barging operations that were sold in November 2015. As a result of the sale, AEP River Operations is no longer a business segment.

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

As of December 31, 2015, AEP's vertically integrated public utility subsidiaries owned or leased approximately 23,600 MW of domestic generation. See Item 2 – Properties for more information regarding the generation capacity of vertically integrated public utility subsidiaries.

Fuel Supply

The 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 generation sources by type, on an actual net generation (MWhs) basis, used by the Vertically Integrated Utilities:

	2015	2014	2013
Coal and Lignite	70%	72%	75%
Nuclear	17%	16%	11%
Natural Gas	12%	11%	13%
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 2015 fossil fuel costs for the Vertically Integrated Utilities decreased approximately 12% on a dollar per MMBtu basis from 2014. This was due to a significant decline in natural gas prices along with a marginal decrease in coal prices.

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 2015 decreased from 2014 due to a decrease in power prices and corresponding decrease in demand for coal-fired generation. As a result, coal inventories ended the year at above-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 4,838 railcars, approximately 498 barges, 12 towboats, 8 harbor boats and a coal handling terminal with approximately 18 million tons of annual capacity to move and store coal for use in AEP generating facilities.

Spot market prices for coal continued to decrease throughout 2015. The decreased spot coal prices reflect the reduction in demand for coal-fired generation and the oversupply in the market. As of December 31, 2015, slightly less than half of the coal purchased by AEP was 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 2015 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:

	2015	2014	2013
Total coal delivered to the plants (millions of tons)	37.3	41.0	51.1
Average cost per ton of coal delivered	$45.36	$46.65	$51.31

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, 2015, the Vertically Integrated Utilities coal inventory was approximately 47 days of full load burn. While inventory targets vary by plant and are changed as necessary, the current coal inventory target for the Vertically Integrated Utilities is approximately 30 days.

Natural Gas

The Vertically Integrated Utilities consumed over 89 billion cubic feet of natural gas during 2015 for generating power. This represents a decrease of 7% from 2014. 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. Several of AEP's natural gas-fired power plants are connected to at least two pipelines which allow greater access to competitive supplies and improve delivery reliability. A portfolio of term, monthly, seasonal, and daily supply and transportation agreements provide natural gas requirements for each plant, as appropriate. AEP's natural gas supply agreements are entered into on a competitive basis and based on market prices.

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 include natural gas delivered to OPCo, while results for 2015 and 2014 do not.

	2015	2014	2013
Total natural gas delivered to the plants (billion cubic feet)	89.7	96.1	158.3
Average price per MMBtu of purchased natural gas	$2.80	$4.70	$4.01

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 was completed in 2015, which consisted of 16 casks. The third dry cask loading is expected to occur in 2018.

16

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 2015. The estimated cost of decommissioning and disposal of low-level radioactive waste for the Cook Plant was $1.6 billion in 2015 non-discounted dollars. As of December 31, 2015, the total decommissioning trust fund balance for the Cook Plant was approximately $1.8 billion. The balance of funds available to eventually 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:

- 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. AEP will seek recovery from customers through regulated rates if actual decommissioning costs exceed projections. See Note 6 to the financial statements, entitled Commitments, Guarantees and Contingencies under the heading Nuclear Contingencies, included in the 2015 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.

Counterparty Risk Management

The Vertically Integrated Utilities segment also sells power and enters into related energy transactions with wholesale customers and other market participants. As a result, counterparties and exchanges may require cash or cash related instruments to be deposited on transactions as margin against open positions. As of December 31, 2015, 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 $52 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 2015 Annual Reports, under the heading entitled Quantitative and Qualitative Disclosures About Market Risk for additional information.

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 have 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%. Under the Inter-Company Power Agreement, which defines the rights of the owners and sets the power participation ratio of each, the sponsoring companies are entitled to receive and are obligated to pay for all OVEC capacity (approximately 2,400 MW) in proportion to their respective power participation ratios. The aggregate power participation ratio of APCo, I&M and OPCo is 43.47%. The Inter-Company Power Agreement terminates in June 2040. 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. 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 cost-based purchased power agreement (PPA) rider that 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. Business – Vertically Integrated Utilities – Regulation – Rates. The FERC regulates and approves the rates for both wholesale transmission transactions and wholesale generation contracts. 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. See Item 1. Business – 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 within a specific territory. 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. Business – Vertically Integrated Utilities – Competition.

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 AEP's 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.

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.

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, management is actively pursuing strategies to accelerate rate recognition of investments and cash flow. AEP representatives continue to engage 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’s vertically integrated public utility subsidiaries operate. Several public utility subsidiaries operate in more than one jurisdiction. See Note 4 to the financial statements, entitled Rate Matters, included in the 2015 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 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 period 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 combined 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 AEP's 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. Federal policy generally fosters competition in the wholesale market by creating a generation market and mandates 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), reliability of service, and availability of capacity and power.

Technology advancements, increased demand for clean energy, changing consumer behaviors, low-priced and abundant natural gas, and regulatory and public policy reforms are among the catalysts for transformation within the industry that impact competition for AEP's vertically integrated public utility subsidiaries. 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, renewables 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 currently maintain a competitive position.

Changes in regulatory policies and advances in newer technologies for batteries or energy storage, fuel cells, microturbines, wind turbines and photovoltaic solar cells are reducing costs of new technology to levels that are making them competitive with some central station electricity production. The costs of photovoltaic solar cells in particular have continued to become increasingly competitive. The ability to maintain relatively low cost, efficient and reliable operations and to provide cost-effective programs and services to customers are significant determinants of AEP’s competitiveness.

While the adoption rate of distributed generation in AEP's service areas has not reached the levels seen in other parts of the country, AEP's vertically integrated utility companies are focused on providing customers with more choices by working with regulators and policymakers to expand, and potentially accelerate, renewable energy offerings. Such additional customer choices consider not only long-term cost, but are also focused on expanding resource diversity. This includes proposed new revenue structures that enable deployment of advanced technologies and resources. In 2015, AEP formed an Enterprise Technology Council to develop and deploy new programs and services designed to receive regulatory support. The vertically integrated public utility subsidiaries of AEP believe that the reliability of their service, the limited ability of customers to substitute other economical sources for electric power and their ability to cost-effectively deploy advanced technologies, such as solar, on a large scale place them in a favorable competitive position.

In the event that alternative generation resources are mandated, subsidized or encouraged through legislation or regulation or otherwise are economically competitive 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 cause AEP to retire generating capacity prior to the end of its estimated useful life. If AEP retires generation plants prior to the end of their estimated useful life, there can be no assurance that AEP will recover the remaining costs associated with such plants. AEP typically recovers undepreciated plant balances and associated operating costs from customers through regulated rates in regulated jurisdictions. Failure to recover these costs could reduce future net income and cash flows and possibly harm financial condition.

Recent changes in the global economy have led to increased competition for many industrial customers in the United States, including those served by the AEP System. 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 work 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. The vertically integrated public utility subsidiaries of AEP also work with customers that seek to source more of their electric power from renewable resources. Depending on the jurisdiction, customers may have access to green power tariffs. In other instances, AEP purchases renewable power that is available to all customers in a specific jurisdiction.

SEASONALITY

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

TRANSMISSION 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 1,468,000 retail customers in Ohio. TCC is engaged in the transmission and distribution of electric power to approximately 826,000 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.

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.

AEP TRANSMISSION HOLDCO (AEPTHCO)

GENERAL

AEPTHCo is a holding company for (a) 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 AEP's existing utility operating companies and (b) AEP's transmission joint ventures.

AEPTCo TRANSCOS

AEP East Transmission Companies (the "AEP East Transmission Companies", all located within PJM)

- AEP Appalachian Transmission Company, Inc. (APTCo)
- 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 (the "AEP West Transmission Companies", all located within SPP)

- AEP Oklahoma Transmission Company, Inc. (OKTCo)
- AEP 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. 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. An application for regulatory approval for SWTCo is under consideration in Louisiana. As of December 31, 2015, AEPTCo's subsidiaries had $2.8 billion of transmission assets in-service with plans to construct approximately $3.5 billion of additional transmission assets through 2018.

AEPTHCo 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.

AEP is 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 millions)		AEP's Investment as of December 31, 2015 (i)		Approved Return on Equity	
ETT	Texas (ERCOT)	(a)		Berkshire Hathaway Energy (50%) AEP (50%)	$3,528.0	(a)	$572.0		9.96	%
Prairie Wind	Kansas	2014		Westar Energy (50%) Berkshire Hathaway Energy (25%) AEP (25%) (b)	158.0		20.6		12.8	%
Pioneer	Indiana	2018	(c)	Duke Energy (50%) AEP (50%)	1,100.0	(c)	16.9		12.54	%
RITELine IN	Indiana	2026		Exelon (12.5%) AEP (87.5%) (d)	400.0		0.1	(e)	11.43	%
RITELine IL	Illinois	2026		Commonwealth Edison (75%) Exelon (12.5%) AEP (12.5%) (d)	1,200.0		—	(e)	11.43	%
Transource Missouri	Missouri	2016		Great Plains Energy (13.5%) AEP (86.5%) (f)	331.0		81.3		11.1	% (g)
Transource West Virginia	West Virginia	2019		Great Plains Energy (13.5%) (f) AEP (86.5%) (f)	60.0		—		—	(h)

(a)

ETT is undertaking multiple projects and the completion dates will vary for those projects. ETT's investment in completed, current and future projects in ERCOT over the next ten years is expected to be $3.5 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.

(c) 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 $386 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.

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

(e) RITELine IN is a consolidated variable interest entity. RTD received an order from the FERC in October 2011 granting incentives for the RITELine IN and RITELine IL projects. The projects and other segments that are electrically equivalent in nature will continue to be submitted for consideration in the interregional planning process between PJM and MISO as dictated by emerging system needs.

(f) AEP owns 86.5% of Transource Missouri and Transource West Virginia 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.

(g) The ROE represents the weighted average approved return on equity based on the projected costs of two projects currently under development by Transource Missouri: the $65 million Iatan-Nashua project (10.3%) and the $266 million Sibley-Nebraska City project (11.3%).

(h) An application for recovery has been filed and a settlement is pending which calls for 10% Base ROE, together with a 0.50% rider, for Transource West Virginia's 15 mile 138kV line Thorofare project.

(i) RITELine IN, Transource Missouri and Transource West Virginia are consolidated joint ventures by AEP. Therefore, the investment value 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.

AEP's 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 2015 approximately 521 AEPSC employees and 253 operating company employees provided service to one or more joint ventures.

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/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 11.2% 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 base filings described above, the Transcos in aggregate filed rate base totals of $2.3 billion in 2015, $1.4 billion for 2014 and $776 million for 2013. The total transmission revenue requirement filed in the ATRR, including prior year over/under-recovery of revenue and associated carrying charges, for 2015, 2014, 2013 and 2012 was $363 million, $231 million, $107 million and $34 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. In November 2015, the PUCT ordered ETT to file a base rate case by February 2017. A base rate review could produce a refund if ETT incurs a disallowance of the transmission investment on which an interim TCOS increase was based. A refund of interim transmission rates would reduce future net income and cash flows. Management is unable to determine a range of potential losses that are reasonably possible of occurring. See Note 4 to the financial statements, entitled Rate Matters, included in the 2015 Annual Reports, for more information regarding pending rate matters.

AEP's 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 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.

GENERATION & MARKETING

GENERAL

The AEP 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 the Generation & Marketing segment is AGR. AGR owns 6,752 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 wholesale energy trading and marketing business, AEP Generation & Marketing segment subsidiaries enter into short and long-term transactions to buy or sell capacity, energy and ancillary services in ERCOT, SPP, MISO and PJM. These subsidiaries 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 the retail supply and energy management business, AEP's 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 375,000 customer accounts as of December 31, 2015.

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. AGR is 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 AEP Generation & Marketing segment subsidiaries face competition for the sale of available power, capacity and ancillary services. The principal factors of impact are electricity and fuel prices, new market entrants, construction or retirement of generating assets by others and technological advances in power generation. Because much of AGR's generation is coal-fired, lower relative natural gas prices will favor competitors that have a higher concentration of natural gas fueled generation. Other factors impacting competitiveness include environmental regulation, transmission congestion or transportation constraints at or near generation facilities, inoperability or inefficiencies, outages and deactivations and retirements at generation facilities.

Technology advancements, increased demand for clean energy, changing consumer behaviors, low-priced and abundant natural gas, and regulatory and public policy reforms are among the catalysts for transformation within the industry that impact competition for AEP's Generation & Marketing segment. AGR also competes with self-generation and with distributors of other energy sources, such as natural gas, fuel oil, renewables and coal, within their service areas. The primary factors in such competition are price, unit availability and the capability of customers to utilize sources of energy other than electric power.

Changes in regulatory policies and advances in newer technologies for batteries or energy storage, fuel cells, microturbines, wind turbines and photovoltaic solar cells are reducing costs of new technology to levels that are making them competitive with some central station electricity production. The ability to maintain relatively low cost, efficient and reliable operations and to provide cost-effective programs and services to customers are significant determinants of AGR's competitiveness. The costs of photovoltaic solar cells in particular have continued to become increasingly competitive.

While the adoption rate of distributed generation in areas that AGR sells power has not reached the levels seen in other parts of the country, AEP expects these trends to continue. AGR believes that the unit availability, the limited ability of customers to substitute other economical sources for electric power and its ability to cost-effectively deploy advanced technologies, such as solar, on a large scale place it in a favorable competitive position.

In the event that alternative generation resources are mandated, subsidized or encouraged through climate legislation or regulation or otherwise are economically competitive 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 cause AGR to retire generating capacity prior to the end of its estimated useful life. If AGR retires generation plants prior to the end of their estimated useful life, there can be no assurance that AGR will recover the remaining costs associated with such plants and may be forced to shut down competitive units.

Recent changes in the global economy have led to increased competition for many industrial customers in the United States, including those served by the Generation & Marketing segment. 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 Generation & Marketing segment works with such customers to meet their business needs through, for example, providing various off-peak or interruptible supply options. The Generation & Marketing segment also works with customers that seek to source more of their electric power from renewable resources.

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.

Fuel Supply

The table shows the generation sources by type, on an actual net generation (MWhs) basis, used by the Generation and Marketing segment, not including the Oklaunion generating unit:

	2015	2014
Coal	75%	88%
Natural Gas	25%	12%
Fuel Oil and other	< 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.

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 its contracts with third party transporters, has the ability to adequately move and store coal and consumables for use in its generating facilities. AGR plants consumed 11.2 million tons of coal in 2015.

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. AGR likes to maintain the coal inventory of its managed plants in the range of 15 to 40 days of full load burn. As of December 31, 2015, the coal inventory of AGR was approximately 57 days of full load burn.

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 86 billion cubic feet of natural gas in 2015, an increase of approximately 73% from 2014.

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, 2015, counterparties posted approximately $26 million in cash, cash equivalents or letters of credit with AEP for the benefit of AEP’s Generation & Marketing segment subsidiaries (while, as of that date, AEP’s Generation & Marketing segment subsidiaries posted approximately $225 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 2015 Annual Reports, under the heading entitled Quantitative and Qualitative Disclosures About Market Risk for additional information.

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 supplied capacity for OPCo's switched and non-switched retail load for the period January 1, 2014 through May 31, 2015.

Other

As of December 31, 2015, 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 RIVER OPERATIONS

Prior to its sale in November 2015, AEP River Operations segment transported liquid, coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi rivers. As a result of the sale, AEP River Operations is no longer a business segment.

EXECUTIVE OFFICERS OF AEP

The following persons are executive officers of AEP. Their ages are given as of February 23, 2016. 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 55
Chairman of the Board since January 2014, President since January 2011 and Chief Executive Officer since November 2011.

Lisa M. Barton
Executive Vice President – Transmission
Age 50
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.

David M. Feinberg
Executive Vice President, General Counsel and Secretary
Age 46
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 55
Senior Vice President and Chief Administrative Officer since December 2012. Previously served as South Region leader – Senior Partner at Aon Hewitt since 2010.

Mark C. McCullough
Executive Vice President – Generation
Age 56
Executive Vice President – Generation of AEPSC since January 2011.

Robert P. Powers
Executive Vice President and Chief Operating Officer
Age 62
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 48
Executive Vice President and Chief Financial Officer since October 2009.

Charles E. Zebula
Executive Vice President – Energy Supply

Age 55
Executive Vice President – Energy Supply since January 2013. Was Senior Vice President – Investor Relations and Treasurer from September 2008 to December 2012.

ITEM 1A. RISK FACTORS

In addition to other disclosures within this report, including Management's Discussion and Analysis of Financial Condition and Results of Operations, and other documents filed with the SEC from time to time, the following factors should be considered in evaluating the Registrants. Such factors could affect actual results of operations and cause results to differ substantially from those currently expected or sought. As indicated below, many of the following risk factors apply to AEP and several or all of the Registrant Subsidiaries and, accordingly, such risk factors should be read to include the applicable Registrants.

GENERAL RISKS OF REGULATED OPERATIONS

AEP may not be able to recover the costs of substantial planned investment in capital improvements and additions. (Applies to all Registrants)

AEP's 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. AEP's 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 charged, affected AEP subsidiaries would not be able to recover the costs associated with their planned extensive investment. This would cause financial results to be diminished.

Regulated electric revenues, earnings and results are dependent on state regulation that may limit AEP's ability to recover costs and other amounts. (Applies to all Registrants)

The rates customers pay to AEP 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 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 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 negatively impact financial condition. Similarly, if recovery or other rate relief authorized in the past is overturned or reversed on appeal, 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.

AEP's transmission investment strategy and execution bears certain risks associated with these activities. (Applies to all Registrants)

Management expects that a growing portion of AEP's earnings in the future will be derived from the transmission investments and activities of AEPTCo and 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, AEP's strategy of investing in transmission could be impacted. Management believes AEP's experience with transmission facilities construction and operation gives AEP 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 new transmission projects or will award such projects to AEP. If the FERC were to lower the rate of return it has authorized for AEP's 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 negatively impact financial condition.

AEP may not recover costs incurred to begin construction on projects that are canceled. (Applies to all Registrants)

AEP's 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, AEP and its subsidiaries 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 are canceled for any reason, including failure to receive necessary regulatory approvals and/or siting or environmental permits, significant cancellation penalties under the equipment purchase orders and construction contracts could occur. In addition, if any construction work or investments have been recorded as an asset, an impairment may need to be recorded in the event the project is canceled.

AEP is exposed to nuclear generation risk. (Applies to AEP and I&M)

Through I&M, AEP owns the Cook Plant. It consists of two nuclear generating units for a rated capacity of 2,191 MW, or about 7% of the generating capacity in the AEP System. AEP and I&M 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 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. In addition, although management has no reason to anticipate a serious nuclear incident at the Cook Plant, if an incident did occur, it could harm 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 AEP or I&M 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. The ability to obtain adequate and timely recovery of costs associated with the Cook Plant is not assured.

The different regional power markets in which AEP subsidiaries compete or will compete in the future have changing market and transmission structures, which could affect performance in these regions. (Applies to all Registrants)

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 costs or revenues. Because the manner in which RTOs will evolve remains unclear, management is unable to assess fully the impact that changes in these power markets may have on the business.

AEP could be subject to higher costs and/or penalties related to mandatory reliability standards. (Applies to all Registrants)

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 AEP to higher operating costs and/or increased capital expenditures. While management expects 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 AEP were found not to be in compliance with the mandatory reliability standards, AEP 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

AEP's financial performance may be adversely affected if AEP is unable to successfully operate facilities or perform certain corporate functions. (Applies to all Registrants)

Performance is highly dependent on the successful operation of 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 AEP's information technology infrastructure or disrupts normal business operations.
- Information technology failure that affects AEP's ability to access customer information or causes loss of confidential or proprietary data that materially and adversely affects AEP's reputation or exposes AEP to legal claims.
- Fuel or water supply interruptions caused by transportation constraints, adverse weather such as drought, non-performance by suppliers and other factors.
- Catastrophic events such as fires, earthquakes, explosions, hurricanes, tornados, ice storms, terrorism (including cyber-terrorism), floods or other similar occurrences.
- Fuel costs and related requirements triggered by financial stress in the coal industry.

Hostile cyber intrusions could severely impair operations, lead to the disclosure of confidential information and damage AEP's reputation. (Applies to all Registrants)

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

A successful cyber attack on the systems that control generation, transmission, distribution or other assets could severely disrupt business operations, preventing service to customers or collection of revenues. The breach of certain business systems could affect the 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 AEP's 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. For these reasons, a significant cyber incident could reduce future net income and cash flows and negatively impact financial condition.

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

If AEP is unable to access capital markets on reasonable terms, it could reduce future net income and cash flows and negatively impact financial condition. (Applies to all Registrants)

AEP relies 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 AEP's ability to raise capital and fund capital needs, including construction costs and refinancing maturing indebtedness. In addition, certain sources of debt and equity capital gave expressed increasing unwillingness to invest in companies, such as AEP, that rely on fossil fuels. If sources of capital for AEP disappear, capital costs could increase materially. Restricted access to capital markets and/or increased borrowing costs could reduce future net income and cash flows and negatively impact financial condition.

Downgrades in AEP's credit ratings could negatively affect its ability to access capital and/or to operate the power trading businesses. (Applies to all Registrants)

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

AEP's power trading business relies on the investment grade ratings of AEP's individual public utility subsidiaries' senior unsecured long-term debt or on the investment grade ratings of AEP. Most counterparties require the creditworthiness of an investment grade entity to stand behind transactions. If those ratings were to decline below investment grade, AEP's ability to operate the power trading business profitably would be diminished because AEP would likely have to deposit cash or cash-related instruments which would reduce future net income and cash flows and negatively impact financial condition.

AEP has no income or cash flow apart from dividends paid or other obligations due it from its subsidiaries. (Applies to AEP)

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

AEP's operating results may fluctuate on a seasonal or quarterly basis and with general economic and weather conditions. (Applies to all Registrants)

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, 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 AEP enters into. 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 reduce future net income and cash flows and negatively impact financial condition. In addition, unusually extreme weather conditions could impact AEP's results of operations in a manner that would not likely be sustainable.

Further, deteriorating economic conditions generally result in reduced consumption by 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 future net income and cash flows and negatively impact financial condition.

Failure to attract and retain an appropriately qualified workforce could harm results of operations. (Applies to all Registrants)

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 the business. If AEP is unable to successfully attract and retain an appropriately qualified workforce, future net income and cash flows may be reduced.

Changes in the price of commodities, emission allowances for criteria pollutants and the costs of transport may increase AEP's cost of producing power or decrease the amount received from selling power, impacting financial performance. (Applies to all Registrants)

AEP is exposed to changes in the price and availability of coal and the price and availability to transport coal. AEP has existing contracts of varying durations for the supply of coal, but as these contracts end or if they are not honored, AEP may not be able to purchase coal on terms as favorable as the current contracts. Similarly, AEP is exposed to changes in the price and availability of emission allowances. AEP uses emission allowances based on the amount of coal used as fuel and the reductions achieved through emission controls and other measures. As long as current environmental programs remain in effect, AEP has sufficient emission allowances to cover the majority of the 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 AEP needs to obtain allowances under a replacement rule, those purchases may not be on as favorable terms as those under the current environmental programs. AEP's 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.

AEP also owns natural gas-fired facilities which exposes AEP 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. AEP's 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 AEP's sales prices, so the margins realized from sales will be lower and, on occasion, AEP may need to curtail operation of marginal plants. Management expects 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 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 negatively impact financial condition.

In addition, actual power prices and fuel costs will differ from those assumed in financial projections used to value trading and marketing transactions, and those differences may be material. As a result, as those transactions are marked to market, they may impact future results of operations and cash flows and impact financial condition.

AEP is subject to physical and financial risks associated with climate change. (Applies to all Registrants)

Climate change creates physical and financial risk. Physical risks from climate change may include an increase in sea level and changes in weather conditions, such as changes in precipitation and extreme weather events. 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 AEP to invest in additional generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather changes may affect 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 the AEP service territory could also have an impact on revenues. AEP buys and sells electricity depending upon system needs and market opportunities. Extreme weather conditions creating high energy demand on AEP's own and/or other systems may raise electricity prices as AEP buys short-term energy to serve AEP's own system, which would increase the cost of energy AEP provides to customers.

Severe weather impacts AEP's service territories, primarily when thunderstorms, tornadoes, hurricanes, floods and snow or ice storms occur. To the extent the frequency of extreme weather events increases, this could increase AEP's cost of providing service. Changes in precipitation resulting in droughts, water shortages or floods could adversely affect operations, principally the fossil fuel generating units. A negative impact to water supplies due to long-term drought conditions or severe flooding could adversely impact AEP's ability to provide electricity to customers, as well as increase the price they pay for energy. AEP 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 revenues. AEP's financial performance is tied to the health of the regional economies AEP serves. 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 the communities within the AEP System.

Management cannot predict the outcome of the legal proceedings relating to AEP's business activities. (Applies to all Registrants)

AEP is involved in legal proceedings, claims and litigation arising out of its business operations, the most significant of which are summarized in Note 6 of the Notes to 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 negatively impact financial condition.

RISKS RELATING TO STATE RESTRUCTURING

Collection of revenues in Texas is concentrated in a limited number of REPs. (Applies to AEP)

Revenues from the distribution of electricity in the ERCOT area of Texas are collected from REPs that supply the electricity AEP distributes to REP customers. Currently, AEP does business with approximately one hundred REPs. In 2015, TCC's largest REP accounted for 23% of its operating revenue and its second largest REP accounted for 22% of its operating revenue; TNC's largest REP accounted for 11% of its operating revenues, and its second largest REP accounted for 10% 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 services or cause them to delay such payments. AEP depends on these REPs for timely remittance of payments. Any delay or default in payment could reduce future cash flows and negatively impact financial condition.

RISKS RELATED TO OWNING AND OPERATING GENERATION ASSETS AND SELLING POWER

Costs of compliance with existing environmental laws are significant. (Applies to all Registrants)

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 AEP to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees and permits at all AEP facilities and could cause AEP to retire generating capacity prior to the end of its estimated useful life. These expenditures have been significant in the past, and management expects 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 negatively impact financial condition, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed or additional substances become regulated. If AEP retires generation plants prior to the end of their estimated useful life, there can be no assurance that AEP will recover the remaining costs associated with such plants. AEP typically recovers 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 future net income and cash flows and possibly harm financial condition.   For AEP's merchant generation units, there is no such cost-recovery mechanism.   As a result, AEP may not recover costs through the market and may be forced to shut competitive units down. The costs of compliance for AEP's competitive units could reduce future net income and cash flows and possibly harm financial condition.

Regulation of CO_2 emissions could materially increase costs to AEP and its customers or cause some electric generating units to be uneconomical to operate or maintain. (Applies to all Registrants)

In 2015, the Federal EPA issued final CO_2 emissions standards for new power generation sources, and final emission guidelines for existing fossil fuel fired electric generating units. The standards for new coal-fired generating units are based on the use of partial carbon capture and storage. The standards for natural gas combined cycle units are based on the use of efficient combined cycle generating technology. The Clean Power Plan guidelines for existing sources include aggressive emission rate goals that are composed of a number of measures and seek nationwide reductions of CO_2 emissions of approximately 32% from 2005 levels by 2030. The Clean Power Plan is intended to be implemented pursuant to individual state plans beginning in 2022. In February 2016, the U.S. Supreme Court issued a stay on the final Clean Power Plan, including all of the deadlines for submission of initial or final state plans. The stay will remain in effect until a final decision is issued by the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court considers any petition for review. All of the final requirements are currently the subject of litigation in the federal courts.

CO_2 standards could require significant increases in capital expenditures and operating costs and could cause AEP to retire generating capacity prior to the end of its estimated useful life. If AEP retires generation plants prior to the end of their estimated useful life, there can be no assurance that AEP will recover the remaining costs associated with such plants. AEP typically recovers 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 future net income and cash flows and possibly harm financial condition. For AEP's merchant generation units, there is no such cost-recovery mechanism. As a result, AEP may not recover costs through the market and may be forced to shut competitive units down. The costs of compliance for AEP's competitive units could reduce future net income and cash flows and possibly harm financial condition.

AEP's financial performance may be adversely affected if the merchant generation fleet is not profitable or loses value. (Applies to AEP)

Management is evaluating strategic alternatives for AEP's merchant generation fleet, which primarily includes AGR's generation fleet which operates in PJM. Management has not made a decision regarding the potential alternatives, nor have they 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 harm financial condition.

Amounts AEP receives from the results of PJM capacity auctions associated with nonregulated generation assets could fail to adequately compensate AEP. (Applies to AEP)

Financial returns on AGR's generation capacity are subject to the results of annual PJM capacity auctions. Auction results indicate a great deal of volatility and the possibility of clearing prices substantially lower than the cost of such capacity. If the PJM capacity auctions result in clearing prices lower than the cost of AEP's capacity, it could reduce future net income and cash flows and harm financial condition.

Courts adjudicating nuisance and other similar claims in the future may order AEP to pay damages or to limit or reduce emissions. (Applies to all Registrants)

In the past, there have been several cases seeking damages based on allegations of federal and state common law nuisance in which AEP, 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 AEP, substantial modifications of AEP's existing coal-fired power plants could be required and AEP might be required to limit or reduce emissions. Such remedies could require AEP to purchase power from third parties to fulfill AEP's commitments to supply power to AEP customers. This could have a material impact on costs. In addition, AEP 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 AEP jurisdictions where generation rates are set on a cost of service basis, without such recovery, those costs could reduce future net income and cash flows and harm financial condition. Moreover, 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 generating facilities. (Applies to all Registrants)

AEP primarily generates electricity at large central facilities. This method results in economies of scale and generally lower costs than (a) newer technologies such as fuel cells and microturbines, 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. Changes in regulatory policies and advances in batteries or energy storage, wind turbines and photovoltaic solar cells are reducing costs of new technology to levels that are making them competitive with some central station electricity production. The ability to maintain relatively low cost, efficient and reliable operations and to provide cost-effective programs and services to customers are significant determinants of AEP’s competitiveness. The costs of photovoltaic solar cells in particular have continued to become increasingly competitive. 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 results of operations.

Further, in the event that alternative generation resources are mandated, subsidized or encouraged through climate legislation or regulation or otherwise are economically competitive 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 AEP's financial condition, results of operations and cash flows, and could also result in an impairment of certain long-lived assets.

Profitability is impacted by AEP's continued authorization to sell power at market-based rates. (Applies to all Registrants)

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 results of operations.

Revenues and results of operations from selling power are subject to market risks that are beyond AEP's control. (Applies to all Registrants)

AEP sells power from its generation facilities into the spot market and other competitive power markets on a contractual basis. AEP also enters into contracts to purchase and sell electricity, natural gas, emission allowances and coal as part of its power marketing and energy trading operations. With respect to such transactions, the rate of return on capital investments is not determined through mandated rates, and revenues and results of operations are likely to depend, in large part, upon prevailing market prices for power in regional markets and competitive markets. These market prices can fluctuate substantially over relatively short periods of time. Sales 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 AEP can obtain for power sales may not change at the same rate as changes in fuel and/or emissions costs. These factors could reduce margins and therefore diminish 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.
- RTO market structures.

Commodity trading and marketing activities are subject to inherent risks which can be reduced and controlled but not eliminated. (Applies to all Registrants)

The exposure of AEP's power trading activities is managed 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, management cannot predict the impact that AEP's energy trading and risk management decisions may have on AEP's business, operating results or financial position.

AEP routinely has open trading positions in the market, within guidelines set by AEP, resulting from the management of AEP's trading portfolio. To the extent open trading positions exist, fluctuating commodity prices can improve or diminish financial results and financial position.

AEP's power trading risk management activities, including 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 policies and procedures are followed and decisions are made based on these estimates, results of operations may be impacted if the judgments and assumptions underlying those calculations prove to be inaccurate.

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

In connection with these trading activities, AEP routinely enters into financial contracts, including futures and options, over-the counter options, financially-settled swaps and other derivative contracts. These activities expose AEP to risks from price movements. If the values of the financial contracts change in a manner AEP does not anticipate, it could harm financial position or reduce the financial contribution of trading operations.

Parties with whom AEP has contracts may fail to perform their obligations, which could harm AEP's results of operations. (Applies to all Registrants)

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

AEP relies on electric transmission facilities that AEP does not own or control. If these facilities do not provide AEP with adequate transmission capacity, AEP may not be able to deliver wholesale electric power to the purchasers of AEP's power. (Applies to all Registrants)

AEP depends on transmission facilities owned and operated by other nonaffiliated power companies to deliver the power AEP sells at wholesale. This dependence exposes AEP to a variety of risks. If transmission is disrupted, or transmission capacity is inadequate, AEP may not be able to sell and deliver AEP wholesale power. If a region's power transmission infrastructure is inadequate, AEP's 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 not be available if transmission capacity is insufficient because of physical constraints or because it is contractually unavailable. Management 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, 2015 the AEP System owned (or leased where indicated) generation plants, all situated in the states in which AEP's 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	2,930	1971
Clinch River (a)	2	VA	Steam - Coal	470	1958
Mountaineer	1	WV	Steam - Coal	1,320	1980
Total MWs (b)				6,650	

(a) Clinch River Unit 3 was retired on May 31, 2015. Clinch River Units 1 and 2 are currently being converted to gas and will be re-rated in 2016.

(b) Glen Lyn, Kanawha River and Sporn Plants were retired in May 2015.

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	8	IN	Hydro	5	1904
Rockport (Units 1 and 2, 50% of each) (a)	2	IN	Steam - Coal	1,310	1984
Cook	2	MI	Steam - Nuclear	2,191	1975
Total MWs (b)				3,523	

(a) Rockport, Unit 2 is leased.
(b) Tanners Creek was retired in May 2015.

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				
2015	82.4	%	89.7	%
2014	82.7	%	86.9	%
2013	96.9	%	87.4	%

KPCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Big Sandy (a)	1	KY	Steam - Coal	278	1963
Mitchell (b)	2	WV	Steam - Coal	780	1971
Total MWs				1,058	

(a) Big Sandy Unit 2 was retired on May 31, 2015. Big Sandy Unit 1 is being converted to gas and will be re-rated in 2016.
(b) KPCo owns a 50% interest in the Mitchell Units. WPCo owns the remaining 50%. Figures presented reflect only the portion owned by KPCo.

PSO

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Comanche	3	OK	Natural Gas	260	1973
Riverside, Units 3 and 4	2	OK	Natural Gas	170	2008
Southwestern, Units 4 and 5	2	OK	Natural Gas	170	2008
Weleetka	3	OK	Natural Gas	185	1975
Northeastern, Unit 1	1	OK	Natural Gas	464	1961
Northeastern, Units 3 and 4	2	OK	Steam - Coal	936	1979
Oklaunion (a)	1	TX	Steam - Coal	102	1986
Northeastern, Unit 2	1	OK	Steam - Natural Gas	461	1961
Riverside, Units 1 and 2	2	OK	Steam - Natural Gas	907	1974
Southwestern, Units 1, 2 and 3	3	OK	Steam - Natural Gas	458	1952
Tulsa	2	OK	Steam - Natural Gas	319	1956
Total MWs				4,432	

(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	315	2007
Stall	3	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	256	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	3	LA	Steam - Natural Gas	242	1947
Lone Star	1	TX	Steam - Natural Gas	50	1954
Wilkes	3	TX	Steam - Natural Gas	911	1964
Total MWs				5,798	

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

WPCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Mitchell (a)	2	WV	Steam - Coal	780	1971
Total MWs				780	

(a) AGR owned a 50% interest in the Mitchell Units until January 2015 when that interest was transferred to WPCo. A portion of WPCo's interest in the Mitchell Units is not in rate base. KPCo owns the remaining 50%. Figures presented reflect only the portion owned by WPCo.

45

Generation & Marketing Segment
AGR

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	510	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
Mitchell (b)	2	WV	Steam - Coal	—	1971
Stuart (a)	4	OH	Steam - Coal	600	1971
Zimmer (a)	1	OH			