AMERICAN ELECTRIC POWER CO INC
Form 10-K
February 25, 2014

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

FORM 10-K

(Mark One)

T ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2013

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

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

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

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

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

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

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

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

Large accelerated filer	o	Accelerated filer	o

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

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

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

	Aggregate Market Value of Voting and Non-Voting Common Equity Held by Non-Affiliates of the Registrants as of June 30, 2013, the Last Trading Date of the Registrants' Most Recently Completed Second Fiscal Quarter	Number of Shares of Common Stock Outstanding of the Registrants at December 31, 2013
American Electric Power Company, Inc.	$21,842,670,718	487,777,372
		($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, 2013:	Part II
American Electric Power Company, Inc.	
Appalachian Power Company	
Indiana Michigan Power Company	
Ohio Power Company	
Public Service Company of Oklahoma	
Southwestern Electric Power Company	
Portions of Proxy Statement of American Electric Power Company, Inc. for 2014 Annual Meeting of Shareholders.	Part III

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

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

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PART IV

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., an electric utility holding company.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP River Operations	AEP's inland river transportation subsidiary, AEP River Operations LLC, operating primarily on the Ohio, Illinois and lower Mississippi rivers.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP Utilities	AEP Utilities, Inc., a subsidiary of AEP, formerly, Central and South West Corporation.
AEP West Companies	PSO, SWEPCo, TCC and TNC.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a subsidiary of AEPTHCo, is an intermediate holding company that owns seven wholly-owned transmission companies.
AEPTHCo	AEP Transmission Holding Company, LLC, a subsidiary of AEP, is an intermediate holding company that owns our transmission operations joint ventures and AEPTCo.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc, a nonregulated AEP subsidiary that acquired the generation assets and liabilities of OPCo.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
Buckeye	Buckeye Power, Inc., a nonaffiliated corporation.
CAA	Clean Air Act.
CO2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CRES provider	Competitive Retail Electric Service providers under Ohio law that target retail customers by offering alternative generation service.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
EPACT	The Energy Policy Act of 2005.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP and MidAmerican Energy Holdings Company Texas Transco, LLC formed to own and operate electric transmission facilities in ERCOT.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo, that defined the sharing of costs and benefits associated with their respective generation plants. This agreement was terminated January 1, 2014.

IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
kV	Kilovolt.
LPSC	Louisiana Public Service Commission.

MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MW	Megawatt.
NOx	Nitrogen oxide.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NRC	Nuclear Regulatory Commission.
OATT	Open Access Transmission Tariff, filed with FERC.
OCC	Corporation Commission of the State of Oklahoma.
OHTCo	AEP Ohio Transmission Company, Inc.
OKTCo	AEP Oklahoma Transmission Company, Inc.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
REP	Texas Retail Electric Provider.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity for AEP and SWEPCo.
SEC	U.S. Securities and Exchange Commission.
SO2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TA	Transmission Agreement, effective November 2010, among APCo, CSPCo, I&M, KGPCo, KPCo, OPCo and WPCo with AEPSC as agent.
TCA	Transmission Coordination Agreement dated January 1, 1997, by and among, PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two public utility subsidiaries.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

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

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

- Our ability to develop and execute a strategy based on a view regarding prices of electricity and other energy-related commodities.
- Prices and demand for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Our ability to recover through rates or market prices any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.
- Volatility and changes in markets for capacity and electricity, coal and other energy-related commodities, particularly changes in the price of natural gas.

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

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

PART I

ITEM 1. BUSINESS

GENERAL

Overview and Description of Material Subsidiaries

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

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

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, 2013, the subsidiaries of AEP had a total of 18,521 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 960,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. APCo owns 7,885 MW of generating capacity, including 867 MW which acquired it from OPCo in a year-end transaction. APCo uses its generation to serve its retail and other customers. As of December 31, 2013, APCo had 1,967 employees. Among the principal industries served by APCo are paper, rubber, coal mining, textile mill products and stone, clay and glass products. In addition to its AEP System interconnections, APCo is interconnected with the following nonaffiliated utility companies: Carolina Power & Light Company, Duke Carolina and Virginia Electric and Power Company. APCo has several points of interconnection with Tennessee Valley Authority (TVA) and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM. APCo is part of AEP's vertically integrated utility business segment.

I&M

Organized in Indiana in 1907, I&M is engaged in the generation, transmission and distribution of electric power to approximately 587,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. I&M owns or leases 4,518 MW of generating capacity, which it uses to serve its retail and other customers. As of December 31, 2013, I&M had 2,582 employees. Among the principal industries served are primary metals, transportation equipment, electrical and electronic machinery, fabricated metal products, rubber and chemicals and allied products, rubber products and transportation equipment. In addition to its AEP System interconnections, I&M is interconnected with the following nonaffiliated utility companies: Central Illinois Public Service Company, Duke Energy Ohio, Inc., Commonwealth Edison Company, Consumers Energy

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Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, Duke Indiana and Richmond Power & Light Company. I&M is a member of PJM. I&M is part of AEP's vertically integrated utility business segment.

KPCo

Organized in Kentucky in 1919, KPCo is engaged in the generation, transmission and distribution of electric power to approximately 172,000 retail customers in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. KPCo owns 1,858 MW of generating capacity, including 780 MW which acquired it from OPCo in a year-end transaction. KPCo uses its generation to serve its retail and other customers. As of December 31, 2013, KPCo had 642 employees. Among the principal industries served are petroleum refining, coal mining and chemical production. In addition to its AEP System interconnections, KPCo is interconnected with the following nonaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM. KPCo is part of AEP's vertically integrated utility business 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, 2013, KGPCo had 57 employees. KGPCo is part of AEP's vertically integrated utility business 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 1,464,000 retail customers in Ohio. OPCo purchases energy and capacity to serve remaining generation service customers. Effective December 31, 2013, OPCo transferred all of its generation assets at net book value to AGR, a newly formed competitive generation affiliate. As of December 31, 2013, OPCo had 1,542 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. In addition to its AEP System interconnection, OPCo is interconnected with the following nonaffiliated utility companies: Duke Ohio, The Cleveland Electric Illuminating Company, Dayton Power and Light Company, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM. OPCo is part of AEP's transmission and distribution utility business segment.

PSO

Organized in Oklahoma in 1913, PSO is engaged in the generation, transmission and distribution of electric power to approximately 540,000 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 4,427 MW of generating capacity, which it uses to serve its retail and other customers. As of December 31, 2013, PSO had 1,148 employees. Among the principal industries served by PSO are paper manufacturing and timber products, natural gas and oil extraction, transportation, non-metallic mineral production, oil refining and steel processing. In addition to its AEP System interconnections, PSO is interconnected with Empire District Electric Company, Oklahoma Gas and Electric Company, Southwestern Public Service Company and Westar Energy, Inc. PSO is a member of SPP. PSO is part of AEP's vertically integrated utility business segment.

SWEPCo

Organized in Delaware in 1912, SWEPCo is engaged in the generation, transmission and distribution of electric power to approximately 526,000 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 5,724 MW of generating capacity, which it uses to serve its retail and other customers. As of December 31, 2013, SWEPCo had 1,449 employees. Among the principal industries served by SWEPCo are natural gas and oil production, petroleum refining, manufacturing of pulp and paper, chemicals, food processing and metal refining. The territory served by SWEPCo also includes several military installations, colleges and universities. SWEPCo also owns and operates a lignite coal mining operation. In addition to its AEP System interconnections, SWEPCo is interconnected with Central Louisiana Electric Company, Empire District Electric Company, Entergy Corp. and Oklahoma Gas & Electric Company. SWEPCo is a member of SPP. SWEPCo is part of AEP's vertically integrated utility business segment.

TCC

Organized in Texas in 1945, TCC is engaged in the transmission and distribution of electric power to approximately 806,000 retail customers through REPs in southern Texas. TCC sold all of its generation assets. As of December 31, 2013, TCC had 1,021 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. In addition to its AEP System interconnections, TCC is a member of ERCOT. TCC is part of AEP's transmission and distribution utility business segment.

TNC

Organized in Texas in 1927, TNC is engaged in the transmission and distribution of electric power to approximately 188,000 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, 2013, TNC had 312 employees. Among the principal industries served by TNC are petroleum refining, agriculture and the manufacturing or processing of cotton seed products, oil products, precision and consumer metal products, meat products and gypsum products. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT. TNC is part of AEP's transmission and distribution utility business 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. WPCo does not own any generating facilities. WPCo is a member of PJM. It purchases electric power from AGR for distribution to its customers. As of December 31, 2013, WPCo had 47 employees. WPCo is part of AEP's vertically integrated utility business segment.

AEGCo

Organized in Ohio in 1982, AEGCo is an electric generating company. AEGCo owns 2,496 MW of generating capacity. AEGCo sells power at wholesale to AGR, I&M and KPCo. As of December 31, 2013, AEGCo had 79 employees. AEGCo is part of AEP's vertically integrated utility business segment.

AGR

Organized in Delaware in 2011, AGR is a nonregulated AEP subsidiary that acquired OPCo's generation assets and liabilities at net book value as of December 31, 2013. AGR is a competitive generation company that generates power that it sells into the market. AGR also engages in power trading activities. Pursuant to a Power Supply Agreement (PSA) between AGR and OPCo, AGR supplies capacity for OPCo's switched and non-switched retail load for the period January 1, 2014 through May 31, 2015. AGR also supplies the energy needs of OPCo's non-switched retail load that is not acquired through auctions from January 1, 2014 through December 31, 2014 under the PSA. AGR owns 10,002 MW of generating capacity, with rights to an additional 1,186 MW pursuant to a unit power agreement with AEGCo. As of December 31, 2013, AGR had 929 employees. AGR is part of AEP's Generation & Marketing business segment.

AEPTHCo

Organized in Delaware in 2012, AEPTHCo is a holding company for AEP's transmission operations joint ventures. AEPTHCo also owns AEPTCo, a holding company for seven FERC-regulated transmission-only electric utilities, each of which is geographically aligned with our existing utility operating companies. The transmission companies develop and own new transmission assets that are physically connected to AEP's system. Individual transmission companies have obtained the approvals necessary to operate in Indiana, Kentucky, Michigan, Ohio, Oklahoma and West Virginia, subject to any applicable siting requirements, and are authorized to submit projects for commission approval in Virginia. Applications for transmission companies are pending with the applicable commissions in Arkansas and Louisiana. Neither AEPTCo nor the transmission companies have any employees. Instead, AEPSC and certain of our utility subsidiaries provide the services required by these entities. AEPTCo is part of the AEP Transmission Holdco business segment.

Service Company Subsidiary

AEP also owns a service company subsidiary, AEPSC. AEPSC provides accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost to the AEP affiliated companies. The executive officers of AEP and certain of its public utility subsidiaries are employees of AEPSC. As of December 31, 2013, AEPSC had 5,392 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	26%	OPCo	10.2% (c)
Texas	14%	TCC	9.96%
		TNC	9.96%
		SWEPCo	9.65%
West Virginia	12%	APCo	10.00%
		WPCo	10.00%
Virginia	13%	APCo	10.90%
Oklahoma	10%	PSO	10.15%
Indiana	10%	I&M	10.20%
Louisiana	5%	SWEPCo	10.00%
Kentucky	5%	KPCo	10.50%
Arkansas	2%	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, 2013.
(b) Identifies the predominant authorized return on equity and may not include other, less significant, permitted recovery. Actual return on equity varies from authorized return on equity.
(c) OPCo's authorized return on equity for distribution rates is 10.2%. OPCo's generation revenues are governed by its Electric Security Plan (ESP) as approved by the PUCO.

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, 2013, 2012 and 2011 are as follows:

Description	Years Ended December 31, 2013	2012	2011
		(in millions)	
Vertically Integrated Utilities Segment			
Retail Revenues			
Residential Sales	$ 3,216	$ 2,993	$ 3,061
Commercial Sales	2,002	1,886	1,884
Industrial Sales	2,029	1,951	1,905
PJM Net Charges	10	(25)	(43)
Provision for Rate Refund	(16)	(3)	1
Other Retail Sales	172	164	164
Total Retail Revenues	7,413	6,966	6,972
Wholesale Revenues			
Off-System Sales	1,671	1,583	1,788
Transmission	133	103	43
Total Wholesale Revenues	1,804	1,686	1,831
Other Electric Revenues	90	98	87
Other Operating Revenues	39	35	52
Sales to Affiliates	646	633	760
Total Revenues Vertically Integrated Utilities Segment	9,992	9,418	9,702
Transmission and Distribution Utilities Segment			
Retail Revenues			
Residential Sales	2,164	2,121	2,146
Commercial Sales	1,161	1,331	1,435
Industrial Sales	549	821	1,048
PJM Net Charges	21	22	45
Provision for Rate Refund	22	(3)	6
Other Retail Sales	39	41	40
Total Retail Revenues	3,956	4,333	4,720
Wholesale Revenues			
Off-System Sales	31	57	34
Transmission	228	205	153
Total Wholesale Revenues	259	262	187
Other Electric Revenues	56	58	70
Other Operating Revenues	8	6	5
Sales to Affiliates	199	159	174
Total Revenues Transmission and Distribution Utilities Segment	4,478	4,818	5,156
Generation and Marketing Segment			
Generation Revenues			

Affiliated		2,457		2,584		3,331
Nonaffiliated		314		282		258
Trading, Marketing and Retail Revenues						
Affiliated		-		1		1
Nonaffiliated		868		572		278
Wind Generation Revenues						
Nonaffiliated		26		28		27
Total Revenues Generation and Marketing Segment	$	3,665	$	3,467	$	3,895

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APCo

Description	2013	2012	2011
	Years Ended December 31, (in thousands)		
Retail Revenues			
Residential Sales	$ 1,219,649	$ 1,159,576	$ 1,107,199
Commercial Sales	583,835	576,153	535,040
Industrial Sales	697,043	701,603	638,854
PJM Net Charges	4,998	(13,049)	(23,696)
Other Retail Sales	77,182	72,455	64,741
Total Retail Revenues	2,582,707	2,496,738	2,322,138
Wholesale Revenues			
Off-System Sales	433,575	409,527	504,955
Transmission	21,049	14,059	(19,723)
Total Wholesale Revenues	454,624	423,586	485,232
Other Electric Revenues	22,246	28,438	29,649
Total Electric Generation, Transmission and Distribution Revenues	3,059,577	2,948,762	2,837,019
Sales to Affiliates	347,484	318,199	358,264
Other Revenues	10,345	9,970	9,942
Total Revenues	$ 3,417,406	$ 3,276,931	$ 3,205,225

I&M

Description	2013	2012	2011
	Years Ended December 31, (in thousands)		
Retail Revenues			
Residential Sales	$ 565,822	$ 505,142	$ 503,554
Commercial Sales	400,810	377,302	369,471
Industrial Sales	455,067	430,042	412,562
PJM Net Charges	3,318	(9,003)	(14,485)
Provision for Rate Refund	-	-	(461)
Other Retail Sales	6,945	6,508	6,693
Total Retail Revenues	1,431,962	1,309,991	1,277,334
Wholesale Revenues			
Off-System Sales	571,802	481,000	499,291
Transmission	4,145	2,092	(14,531)
Total Wholesale Revenues	575,947	483,092	484,760
Other Electric Revenues	14,348	16,986	8,353
Total Electric Generation, Transmission and Distribution Revenues	2,022,257	1,810,069	1,770,447
Sales to Affiliates	341,686	385,460	429,237
Other Revenues	2,916	4,582	15,086
Total Revenues	$ 2,366,859	$ 2,200,111	$ 2,214,770

OPCo

Years Ended December 31,

Description	2013	2012	2011
		(in thousands)	
Retail Revenues			
Residential Sales	$ 1,676,138	$ 1,636,808	$ 1,680,179
Commercial Sales	763,820	945,233	1,077,742
Industrial Sales	468,358	742,235	979,424
PJM Net Charges	6,916	(18,831)	(30,768)
Provision for Rate Refund	22,091	(2,577)	6,035
Other Retail Sales	15,881	18,113	17,714
Total Retail Revenues	2,953,204	3,320,981	3,730,326
Wholesale Revenues			
Off-System Sales	563,040	661,513	667,593
Transmission	17,699	10,114	(26,697)
Total Wholesale Revenues	580,739	671,627	640,896
Other Electric Revenues	28,281	29,508	36,008
Total Electric Generation, Transmission and Distribution Revenues	3,562,224	4,022,116	4,407,230
Sales to Affiliates	1,184,994	886,695	1,005,486
Other Revenues	15,397	19,385	18,395
Total Revenues	$ 4,762,615	$ 4,928,196	$ 5,431,111

PSO

Description	Years Ended December 31, 2013	2012	2011
	(in thousands)		
Retail Revenues			
Residential Sales	$ 530,446	$ 512,372	$ 572,404
Commercial Sales	351,521	331,125	364,701
Industrial Sales	234,072	209,446	241,026
Provision for Rate Refund	-	-	(158)
Other Retail Sales	73,649	70,894	78,722
Total Retail Revenues	1,189,688	1,123,837	1,256,695
Wholesale Revenues			
Off-System Sales	34,636	37,484	42,241
Transmission	36,393	30,669	31,903
Total Wholesale Revenues	71,029	68,153	74,144
Other Electric Revenues	16,994	14,593	14,713
Total Electric Generation, Transmission and Distribution Revenues	1,277,711	1,206,583	1,345,552
Sales to Affiliates	14,246	22,603	14,192
Other Revenues	3,565	3,752	3,644
Total Revenues	$ 1,295,522	$ 1,232,938	$ 1,363,388

SWEPCo

Description	Year Ended December 31, 2013	2012	2011
	(in thousands)		
Retail Revenues			
Residential Sales	$ 586,517	$ 512,578	$ 554,663
Commercial Sales	472,264	404,204	411,652
Industrial Sales	316,282	298,604	288,474
Provision for Rate Refund	(16,110)	(1,207)	1,604
Other Retail Sales	8,360	8,074	8,118
Total Retail Revenues	1,367,313	1,222,253	1,264,511
Wholesale Revenues			
Off-System Sales	294,594	247,118	259,877
Transmission	59,097	48,404	47,782
Total Wholesale Revenues	353,691	295,522	307,659
Other Electric Revenues	21,571	20,758	22,022
Total Electric Generation, Transmission and Distribution Revenues	1,742,575	1,538,533	1,594,192
Sales to Affiliates	51,812	37,441	57,615
Other Revenues	1,416	1,860	2,019
Total Revenues	$ 1,795,803	$ 1,577,834	$ 1,653,826

(a) Intercompany transactions have been eliminated for the years ended December 31, 2013, 2012 and 2011.

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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 2013 Annual Reports, under the heading entitled Financial Condition for additional information concerning short-term funding and our access to bank lines of credit, commercial paper and capital markets.

AEP’s revolving credit agreements (which backstop the commercial paper program) include covenants and events of default typical for this type of facility, including a maximum debt/capital test and, for AEP and its significant subsidiaries, a $50 million cross-acceleration provision. As of December 31, 2013, 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 2013 Annual Reports, under the heading entitled Financial Condition for additional information with respect to AEP’s credit agreements.

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

ENVIRONMENTAL AND OTHER MATTERS

General

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

Clean Air Act Requirements

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

The Acid Rain Program

The 1990 Amendments to the CAA include a cap-and-trade emission reduction program for SO2 emissions from power plants. By 2000, the program established a nationwide cap on power plant SO2 emissions of 8.9 million tons per year, and required further reductions in 2010. The 1990 Amendments also contain requirements for power plants to reduce NOx emissions through the use of available combustion controls.

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

National Ambient Air Quality Standards

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

Each state identifies the areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (nonattainment areas). Each state must develop a state implementation plan (SIP) to bring nonattainment areas into compliance with the NAAQS and maintain good air quality in attainment areas. All SIPs are submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA develops and implements a plan. As the Federal EPA reviews the NAAQS and establishes new concentration levels, the attainment status of areas can change and states may be required to develop new SIPs. In 2008, the Federal EPA issued revised NAAQS for both ozone and fine particulate matter (PM 2.5). The PM 2.5 standard was remanded by the D.C. Circuit Court of Appeals, and a new rule was signed by the administrator in December 2012 that lowers the annual standard. A new ozone standard is also under development. The Federal EPA also adopted a new short-term standard for SO2 in 2010, a lower standard for NOx in 2010, and a lower standard for lead in 2008. The existing standard for carbon monoxide was retained in 2011. The states will develop new SIPs for these standards, which could result in additional emission reductions being required from our facilities.

In 2005, the Federal EPA issued the Clean Air Interstate Rule (CAIR), which requires additional reductions in SO2 and NOx emissions from power plants and assists states developing new SIPs to meet the NAAQS. For additional information regarding CAIR, see Management's Discussion and Analysis of Financial Condition and Results of Operations under the headings entitled Environmental Issues – Clean Air Act Requirements. In August 2011, the Federal EPA issued a final rule to replace CAIR (the Cross State Air Pollution Rule (CSAPR)) that would impose new and more stringent requirements to control SO2 and NOx emissions from fossil fuel-fired electric generating units in 27 states and the District of Columbia. Petitions for review were filed with the U.S. Court of Appeals for the District of Columbia Circuit, and CSAPR was vacated. That decision is currently under review by the U.S. Supreme Court. CAIR remains in effect until the Federal EPA develops a replacement rule. For additional information regarding CSAPR, see Management's Discussion and Analysis of Financial Condition and Results of Operations under the headings entitled Environmental Issues – Clean Air Act Requirements.

Hazardous Air Pollutants

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

Regional Haze

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

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

CO_2 Regulation

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

Our fossil fuel-fired generating units are large sources of CO_2 emissions. If substantial CO_2 emission reductions are required, there will be significant increases in capital expenditures and operating costs which would hasten the ultimate retirement of older, less-efficient, coal-fired units. To the extent we install additional controls on our generation plants to limit CO_2 emissions and receive regulatory approvals to increase our rates, return on capital investment would have a positive effect on future earnings. Prudently incurred capital investments made by our subsidiaries in rate-regulated jurisdictions to comply with legal requirements and benefit customers are generally included in rate base for recovery and earn a return on investment. We would expect these principles to apply to investments made to address new environmental requirements. However, requests for rate increases reflecting these costs can affect us adversely because our regulators could limit the amount or timing of increased costs that we would recover through higher rates. For our sales of energy based on market rate authority, however, there is no such recovery mechanism.

Several states have adopted programs that directly regulate CO_2 emissions from power plants, but none of these programs are currently in effect in states where we have generating facilities. Some of our states have established mandatory or voluntary programs to increase the use of energy efficiency, alternative energy, or renewable energy sources (Arkansas, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Texas, Virginia, and West Virginia). We are taking steps to comply with these requirements primarily through entering into power supply agreements giving us access to power generated by wind turbines. Federal EPA has been consulting with states to see whether and how such programs might become part of a CO_2 emission reduction program for existing utility generating units. For additional information, see Management's Discussion and Analysis of Financial Condition and Results of Operations under the headings entitled Environmental Issues – Clean Air Act Requirements.

Clean Water Act Requirements

Our operations are also subject to the Federal Clean Water Act, which prohibits the discharge of pollutants into waters of the United States except pursuant to appropriate permits, and regulates systems that withdraw surface water for use in our power plants. In April 2011, the Federal EPA issued a proposed rule setting forth standards for existing power plants that will reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. The proposed standards affect all plants withdrawing more than two million gallons of cooling water per day and establish specific intake design and intake velocity standards meant to allow fish to avoid or escape impingement. Compliance with this standard is required within eight years of the effective date of the final rule. The proposed standard for entrainment for existing facilities requires a site-specific evaluation of the available measures for reducing entrainment. We submitted comments on this proposal and we expect the Federal EPA to issue revised rules in 2014.

The Federal EPA is also engaged in rulemaking to update the technology-based standards that govern discharges from new and existing power plants under the Clean Water Act's National Pollutant Discharge Elimination System program. These standards were last updated over 20 years ago, and the Federal EPA has issued two rounds of information collection requests to inform its rulemaking. In October 2009, the Federal EPA issued a final report for the power plant sector and determined that revisions to its existing standards are necessary. The Federal

EPA proposed revised standards in 2013. 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

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

Climate Change – Position and Strategy

We continue to support a federal legislative approach to energy policy as the most effective means of reducing emissions of CO2 and other greenhouse gases (generally referred to as CO2) that recognizes that a reliable and affordable electricity supply is vital to economic recovery and growth. We do not believe regulating CO2 emissions under the Clean Air Act is the appropriate solution. During the past decade, we have taken voluntary actions to reduce and offset our CO2 emissions. Unfortunately, two of the voluntary programs that helped businesses such as AEP to set quantitative commitments no longer exist. The Federal EPA's Climate Leaders Program and the Chicago Climate Exchange both ended their reduction obligations at the end of 2010. However, through these programs and others, we voluntarily reduced our CO2 emissions by approximately 96 million metric tons during the 2003 to 2010 period.

We expect our emissions to continue to decline over time as we diversify our generating sources and operate fewer coal units. The projected decline in coal-fired generation is due to a number of factors, including the ongoing cost of operating older units, the relative cost of coal and natural gas as fuel sources, increasing environmental regulations requiring significant capital investments and changing commodity market fundamentals. Our strategy for this transformation is to protect the reliability of the electric system and reduce our emissions by pursuing multiple options. These include diversifying our fuel portfolio and generating more electricity from natural gas, increasing energy efficiency and investing in renewable resources, where there is regulatory support. Meanwhile, the Federal EPA began regulating CO2 emissions from large stationary sources such as power plants in 2012 under the New Source Review prevention of significant deterioration and Title V operating permit programs.

In September 2013, the Federal EPA reproposed a Carbon Pollution Standard for New Power Plants. This regulation, based on EPA authority under section 111(b) of the Clean Air Act, would establish New Source Performance Standards for CO2 for new fossil-fueled-fired electric generating units. The proposed regulation would limit the ability to construct new coal-fired facilities in the future due to strict emission limits if they are finalized. AEP does not currently have plans to permit or construct any new coal-fired facilities and the proposed rule does not directly impact existing facilities. The EPA is scheduled to propose standards, regulations or guidelines, as appropriate, for CO2 from existing fossil fuel units in June 2014, though the scope and extent of the standards is currently unknown.

For additional information on legislative and regulatory responses to greenhouse gases, including limitations on CO2 emissions, see Management's Discussion and Analysis of Financial Condition and Results of Operations under the headings entitled Environmental Issues – Climate Change. Specific steps taken to reduce CO2 emissions include the following:

Renewable Sources of Energy

Some of the states we serve have established mandatory or voluntary programs to increase the use of energy efficiency, alternative energy, or renewable energy sources (Arkansas, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Texas, Virginia and West Virginia). At the end of 2013 and in support of our goals or requirements, our operating companies had long-term contracts for 1,984 MW of wind and 10 MW of solar power. When additional contracts for projects under construction and/or pending regulatory approval are added and netted against one wind contract that is expiring at the end of 2015, the total renewable portfolio will be 2,698 MW to serve our regulated operating company customers. We actively manage our compliance position and are on pace to meet the relevant requirements or benchmarks in each applicable jurisdiction.

End Use Energy Efficiency

In 2008, AEP ramped up efforts to reduce energy consumption and peak demand through the introduction of additional energy efficiency and demand response programs. These programs, commonly and collectively referred to as demand side management, were implemented in jurisdictions where appropriate cost recovery was available. Since that time, AEP Operating Companies have implemented over 100 programs across the AEP service territory and in most of the states we serve. For the period 2008 through 2013, these programs have reduced annual consumption by over 4,000,000 megawatt hours and peak demand by over 1,200 MW. To achieve these levels, AEP Operating Companies invested approximately $540 million during the same period. These results are preliminary and subject to independent third party evaluation and verification of savings, as required.

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

Current and Projected CO2 Emissions

Our total CO2 emissions in 2012 (not including our ownership in the Kyger Creek and Clifty Creek plants) were approximately 122 million metric tons. Our 2013 emissions decreased to approximately 114 million metric tons. We expect overall increases in CO2 emissions during the next few years to be small, if any, as our sales and generation rebound somewhat from recession lows in 2009. However, over much of the remainder of the decade we expect emissions to decline as modest sales growth is offset by retirements of older, less efficient coal-fired units and increased utilization of natural gas.

Corporate Governance

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

Other Environmental Issues and Matters

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 imposes costs for environmental remediation upon owners and previous owners of sites, as well as transporters and generators of hazardous material disposed of at such sites. See Note 6 to the consolidated financial statements entitled Commitments, Guarantees and Contingencies, included in the 2013 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 2011, 2012 and 2013 and the current estimates for 2014, 2015 and 2016 are shown below, in each case excluding equity AFUDC. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends and the ability to access capital. AEP expects to make substantial investments in future years in addition to the amounts set forth below in connection with the modification and addition of facilities at generation plants for environmental quality controls. Such future investments are needed in order to comply with air and water quality standards that have been adopted and have deadlines for compliance after 2013 or have been proposed and may be adopted. Future investments could be significantly greater if emissions reduction requirements are accelerated or otherwise become more onerous or if CO2 becomes regulated at existing facilities. The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the AEP System. We typically recover costs of complying with environmental standards from customers through rates in regulated jurisdictions. For our sales of energy based on market rate authority, however, there is no such recovery mechanism. Failure to recover these costs could reduce our future net income and cash flows and possibly harm our financial condition. See Management's Discussion and Analysis of Financial Condition and Results of Operations under the heading entitled Environmental Issues and Note 6 to the consolidated financial statements, entitled Commitments, Guarantees and Contingencies, included in the 2013 Annual Reports, for more information regarding environmental expenditures in general.

Historical and Projected Environmental Investments

	2011 Actual	2012 Actual	2013 Actual	2014 Estimate	2015 Estimate	2016 Estimate
			(in thousands)			
Total AEP (a)	$ 186,800	$ 235,400	$ 415,000	$ 588,000	$ 644,000	$ 447,000
APCo	68,900	50,800	44,500	48,000	67,000	68,000
I&M	5,900	30,400	27,300	55,000	42,000	52,000
OPCo (b)	63,000	66,200	123,900	-	-	-
PSO	6,500	26,100	55,500	66,000	75,000	49,000
SWEPCo	11,000	23,800	134,000	217,000	312,000	118,000

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

(b) Estimates for 2014, 2015 and 2016 reflect the transfer of all of OPCo generation assets which occurred on December 31, 2013.

Electric and Magnetic Fields (EMF)

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

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

BUSINESS SEGMENTS

During the fourth quarter of 2013, we realigned our business segments as a result of corporate separation and plant transfers. See Note 9 to the consolidated financial statements entitled Business Segments, included in the 2013 Annual Reports, for additional information on our operating segments. Our reportable segments and their related business activities are outlined below:

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by OPCo, TCC and TNC.
  - OPCo purchases energy and capacity to serve remaining generation service customers.

Generation & Marketing

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

AEP Transmission Holdco

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

AEP River Operations

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

VERTICALLY INTEGRATED UTILITIES

GENERAL

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

ELECTRIC GENERATION

Facilities and Coordination

As of December 31, 2013, AEP's vertically integrated public utility subsidiaries owned or leased approximately 26,900 MW of domestic generation. See Item 2 – Properties for more information regarding the generation capacity of vertically integrated public utility subsidiaries.

Interconnection Agreement

Until January 1, 2014, AEPSC, APCo, I&M, KPCo and OPCo were parties to the Interconnection Agreement. This agreement defined how the member companies shared the costs and benefits associated with their generation plants. The agreement required the deficit companies to make monthly capacity equalization payments to the surplus companies based on the surplus companies' average fixed cost of generation. All member companies shared off-system sales margins based upon each member company's member load ratio. As of December 31, 2013, the member-load-ratios were as follows:

	Peak Demand (MWs)	Member-Load Ratio (%)
APCo	6,839	31
I&M	4,540	21
KPCo	1,409	6
OPCo	9,385	42

APCo, I&M, KPCo and OPCo were also parties to the AEP System Interim Allowance Agreement (Allowance Agreement), that provided, among other things, for the transfer of SO2 emission allowances associated with transactions under the Interconnection Agreement. The following table shows the net (credits) or charges allocated among the parties under the Interconnection Agreement during the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31,		
	2013	2012	2011
		(in thousands)	
APCo	$ 637,300	$ 494,400	$ 632,100
I&M	(36,500)	(118,400)	(183,700)
KPCo	124,200	93,200	48,400
OPCo	(725,000)	(469,200)	(496,800)

Termination of the Interconnection Agreement

Effective as of January 1, 2014, the Interconnection Agreement and the Allowance Agreement were each terminated. The transfer of OPCo’s generation assets and related liabilities to AGR occurring on December 31, 2013 removed a large proportion of the pooled generation resources governed under the Interconnection Agreement and Allowance Agreement. As a result of these transfers, which were approved by the PUCO and the FERC, the parties terminated the Interconnection Agreement and the Allowance Agreement. See Notes 1 and 4 to the consolidated financial statements, included in the 2013 Annual Reports, for additional information regarding the termination of the Interconnection Agreement and Corporate Separation.

Operating Agreement

AEPSC, PSO and SWEPCo are parties to the Operating Agreement which has been approved by the FERC. The Operating Agreement requires PSO and SWEPCo to maintain adequate annual planning reserve margins and requires that capacity in excess of the required margins be made available for sale to other operating companies as capacity commitments. Parties are compensated for energy delivered to the recipients based upon the deliverer’s incremental cost plus a portion of the recipient’s savings realized by the purchaser that avoids more costly alternatives. Revenues and costs arising from third party sales are generally shared based on the amount of energy PSO or SWEPCo contributes that is sold to third parties.

In January 2014, the FERC approved the modification of the Operating Agreement to address changes resulting from the anticipated March 2014 implementation of a "Day-Ahead" power market by the SPP.

The following table shows the net (credits) or charges allocated among the parties under the Operating Agreement during the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31,		
	2013	2012	2011
		(in thousands)	
PSO	$ 46,171	$ 42,555	$ 33,091
SWEPCo	(46,171)	(42,555)	(33,091)

Power generated by or allocated or provided under the Operating Agreement to any public utility subsidiary is primarily sold to customers by such public utility subsidiary at rates approved by the public utility commission in the jurisdiction of sale.

Power that is not needed to serve the native load of our vertically integrated public utility subsidiaries is sold in the wholesale market by AEPSC on behalf of that subsidiary. See Risk Management and Trading, below, for a discussion of the trading and marketing of such power.

Counterparty Risk Management

Counterparties and exchanges may require cash or cash related instruments to be deposited on transactions as margin against open positions. As of December 31, 2013, counterparties posted approximately $11 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 $59 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 2013 Annual Reports, under the heading entitled Quantitative and Qualitative Disclosures About Market Risk for additional information.

Fuel Supply

The following table and fuel supply presentation under "Fuel Supply", "Coal and Lignite" and "Natural Gas" include the results of the fuel used and transported by OPCo, a utility subsidiary that is not part of the vertically integrated utility segment. OPCo's results appear here because it retained its generation until year-end 2013 at which point all of its generation was transferred to AGR which transferred portions to APCo and KPCo.

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

	2013	2012	2011
Coal and Lignite	75%	71%	78%
Natural Gas	13%	17%	11%
Nuclear	11%	11%	10%
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 2013 fossil fuel costs increased approximately 9% on a dollar per MMBtu basis from 2012 due primarily to an increase in natural gas prices.

Coal and Lignite

AEP's public utility subsidiaries procure coal and lignite under a combination of purchasing arrangements including long-term contracts, affiliate operations and spot agreements with various producers and coal trading firms. Coal consumption in 2013 was down slightly from the same period in 2012, but coal inventories ended the year at target levels on a system basis.

Management believes that AEP's public utility subsidiaries will be able to secure and transport coal and lignite of adequate quality and in adequate quantities to operate their coal and lignite-fired units. Through subsidiaries, AEP owns, leases or controls more than 5,700 railcars, approximately 600 barges, 15 towboats, and a coal handling terminal with approximately 18 million tons of annual capacity to move and store coal for use in our generating facilities. See AEP River Operations for a discussion of AEP's for-profit liquid, coal and other dry-bulk commodity transportation operations that are not part of this business segment.

Spot market prices for coal remained relatively flat throughout 2013, and decreased for certain coals used by AEP. The relatively flat spot coal price performance during the year can be attributed to weak European coal demand, a persistently sluggish domestic economy, and relatively inexpensive natural gas. Approximately half of the coal purchased by AEP is procured through term contracts. As those contracts expire, they are replaced with contracts at current market prices. The price impact of this process is reflected in subsequent periods. The price paid for coal delivered in 2013 increased from the prior year primarily due to an increase in rail rates for western coal.

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

	2013	2012	2011
Total coal delivered to AEP System plants (thousands of tons)	51,057	60,054	62,956
Average cost per ton of coal delivered	$ 51.31	$ 49.22	$ 46.76

The coal supplies at AEP System plants vary from time to time depending on various factors, including, but not limited to, demand for electric power, unit outages, transportation infrastructure limitations, space limitations, plant coal consumption rates, availability of acceptable coals, labor issues and weather conditions, which may interrupt production or deliveries. At December 31, 2013, the System's coal inventory was approximately 34 days of full load burn.

Natural Gas

Through its public utility subsidiaries, AEP consumed over 158 billion cubic feet of natural gas during 2013 for generating power. This represents a decrease of 28% from 2012 and reverses a trend that began in 2010. 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 increase in natural gas prices in 2013 led to a decrease in demand for natural gas-fired generation. Despite the availability of natural gas due to the increased shale supply, the U.S. pipeline infrastructure remains a limiting factor in the expansion of natural gas-fired generation. Several of AEP's natural gas-fired power plants are connected to at least two pipelines, however, which allows greater access to competitive supplies and improves delivery reliability. A portfolio of term, monthly, seasonal firm and daily peaking purchase and transportation agreements (that are entered into on a competitive basis and based on market prices) supplies natural gas requirements for each plant, as appropriate.

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

	2013	2012	2011
Total natural gas delivered to AEP System plants (billion cubic feet)	158.3	220.0	166.8
Average price per MMBtu of purchased natural gas	$ 4.01	$ 3.01	$ 4.48

Nuclear

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

For purposes of the storage of high-level radioactive waste in the form of spent nuclear fuel, I&M completed modifications to its spent nuclear fuel storage pool more than 10 years ago. I&M entered into an agreement to provide for onsite dry cask storage of spent nuclear fuel to permit normal operations to continue. I&M is scheduled to conduct further dry cask loading and storage projects on an ongoing periodic basis. I&M began and completed its initial loading of spent nuclear fuel into the dry casks in 2012, which consisted of 12 casks (32 spent nuclear fuel assemblies contained within each). The second loading of spent nuclear fuel into dry casks is expected to occur in 2015.

Nuclear Waste and Decommissioning

As the owner of the Cook Plant, I&M has a significant future financial commitment to dispose of spent nuclear fuel and decommission and decontaminate the plant safely. The cost to decommission a nuclear plant is affected by NRC regulations and the spent nuclear fuel disposal program. The most recent decommissioning cost study was completed in 2012. In it, the estimated cost of decommissioning and disposal of low-level radioactive waste for the Cook Plant ranged from $1.3 billion to $1.7 billion in 2012 non-discounted dollars. As of December 31, 2013, the total decommissioning trust fund balance for the Cook Plant was approximately $1.6 billion. The balance of funds available to decommission Cook Plant will differ based on contributions and investment returns. The ultimate cost of retiring the Cook Plant may be materially different from estimates and funding targets as a result of the:

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

Accordingly, management is unable to provide assurance that the ultimate cost of decommissioning the Cook Plant will not be significantly different than current projections. We will seek recovery from customers through our regulated rates if actual decommissioning costs exceed our projections. See Note 6 to the consolidated financial statements, entitled Commitments, Guarantees and Contingencies under the heading Nuclear Contingencies, included in the 2013 Annual Reports, for information with respect to nuclear waste and decommissioning.

Low-Level Radioactive Waste

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

Certain Power Agreements

I&M

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

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

OVEC

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

ELECTRIC DELIVERY

General

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

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

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

Transmission Agreement

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

The following table shows the net charges allocated among the certain parties to the TA during the years ended December 31, 2013, 2012 and 2011:

Company	Years Ended December 31, 2013	2012	2011
	(in thousands)		
APCo	$ 40,609	$ 20,264	$ 4,608
I&M	19,947	5,689	1,538

TCA, OATT, and ERCOT Protocols

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

The following table shows the net (credits) or charges allocated pursuant to the TCA and SPP OATT protocols as described above for the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31, 2013	2012	2011
	(in thousands)		
PSO	$ 14,700	$12,300	$9,000
SWEPCo	(14,700)	(12,300)	(9,000)

Transmission Services for Non-Affiliates

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

Coordination of East and West Zone Transmission

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP East Companies and AEP West Companies. The System Transmission Integration Agreement functions as an umbrella agreement in addition to the TA and the TCA. AEP's System Transmission Integration Agreement contains two service schedules that govern:

- The allocation of transmission costs and revenues.
- The allocation of third-party transmission costs and revenues and System dispatch costs.

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

Regional Transmission Organizations

AEGCo, APCo, I&M, KGPCo, KPCo and WPCo are members of PJM, and PSO and SWEPCo are members of the SPP (both FERC-approved RTOs). RTOs operate, plan and control utility transmission assets in a manner designed to provide open access to such assets in a way that prevents discrimination between participants owning transmission assets and those that do not.

REGULATION

General

AEP's vertically integrated public utility subsidiaries' retail rates and certain other matters are subject to traditional cost-based regulation by the state utility commissions. AEP's vertically integrated public utility subsidiaries are also subject to regulation by the FERC under the Federal Power Act with respect to wholesale power and transmission service transactions. I&M is subject to regulation by the NRC under the Atomic Energy Act of 1954, as amended, with respect to the operation of the Cook Plant. AEP and its vertically integrated public utility subsidiaries are also subject to the regulatory provisions of EPACT, much of which is administered by the FERC.

Rates

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

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

The rates of AEP's vertically integrated public utility subsidiaries are generally based on the cost of providing traditional bundled electric service (i.e., generation, transmission and distribution service). Historically, the state regulatory frameworks in the service area of the AEP vertically integrated public utility subsidiaries reflected specified fuel costs as part of bundled (or, more recently, unbundled) rates or incorporated fuel adjustment clauses in a utility's rates and tariffs. Fuel adjustment clauses permit periodic adjustments to fuel cost recovery from customers and therefore provide protection against exposure to fuel cost changes.

The following state-by-state analysis summarizes the regulatory environment of certain major jurisdictions in which AEP operates. Several public utility subsidiaries operate in more than one jurisdiction. See Note 4 to the consolidated financial statements, entitled Rate Matters, included in the 2013 Annual Reports, for more information regarding pending rate matters.

Indiana

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

Oklahoma

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

Virginia

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

West Virginia

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

FERC

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

The FERC oversees RTOs, entities created to operate, plan and control utility transmission assets. Order 2000 also prescribes certain characteristics and functions of acceptable RTO proposals. AEGCo, APCo, I&M, KGPCo, KPCo and WPCo are members of PJM. PSO and SWEPCo are members of SPP.

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

Competition

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

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

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

Seasonality

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

TRANSMISSION AND DISTRIBUTION UTILITIES

General

This business 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 1,464,000 retail customers in Ohio. TCC is engaged in the transmission and distribution of electric power to approximately 806,000 retail customers through REPs in southern Texas. TNC is engaged in the transmission and distribution of electric power to approximately 188,000 retail customers through REPs in west and central Texas.

AEP's transmission and distribution utility subsidiaries own and operate transmission and distribution lines and other facilities to deliver electric power. See Item 2 – Properties for more information regarding the transmission and distribution lines. Most of the transmission and distribution services are sold to retail customers of AEP's transmission and distribution utility subsidiaries in their service territories. These sales are made at rates approved by the PUCT for TCC and TNC and by the PUCO and the FERC for OPCo. The FERC regulates and approves the rates for wholesale transmission transactions. As discussed below, some transmission services also are separately sold to non-affiliated companies.

AEP's transmission and distribution utility subsidiaries hold franchises or other rights to provide electric service in various municipalities and regions in their service areas. In some cases, these franchises provide the utility with the exclusive right to provide electric service. These franchises have varying provisions and expiration dates. In general, the operating companies consider their franchises to be adequate for the conduct of their business.

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

Transmission Agreement

OPCo, together with APCo, I&M, KGPCo, KPCo and WPCo, is a party to the TA. The TA defines how the parties to the agreement share the cost of their transmission facilities. The TA has been approved by the FERC. OPCo's net charges allocated to it under the TA during the years ended December 31, 2013, 2012 and 2011 were $8.9 million, $6.1 million and $17.2 million, respectively.

Regional Transmission Organizations

OPCo is a member of PJM, a FERC-approved RTO. RTOs operate, plan and control utility transmission assets in a manner designed to provide open access to such assets in a way that prevents discrimination between participants owning transmission assets and those that do not. TCC and TNC are members of ERCOT.

REGULATION

OPCo provides distribution and transmission services to retail customers within its service territory at cost-based rates approved by the PUCO or by the FERC. TCC and TNC provide transmission and distribution service on a cost-of-service basis at rates approved by the PUCT and wholesale transmission service under tariffs approved by the FERC consistent with PUCT rules. Transmission and distribution rates are established on a cost-of-service basis, which is designed to allow a utility an opportunity to recover its cost of providing service and to earn a reasonable return on its investment used in providing that service. The cost of service generally reflects operating expenses, including operation and maintenance expense, depreciation expense and taxes. Utility commissions periodically adjust rates pursuant to a review of (a) a utility’s adjusted revenues and expenses during a defined test period and (b) such utility’s level of investment.

FERC

Under the Federal Power Act, the FERC regulates rates for transmission of electric power, accounting and other matters. The FERC regulations require AEP to provide open access transmission service at FERC-approved rates. The FERC also regulates unbundled transmission service to retail customers. The FERC requires each public utility that owns or controls interstate transmission facilities to, directly or through an RTO, file an open access network and point-to-point transmission tariff that offers services comparable to the utility’s own uses of its transmission system. The FERC also requires all transmitting utilities, directly or through an RTO, to establish an Open Access Same-time Information System, which electronically posts transmission information such as available capacity and prices, and requires utilities to comply with Standards of Conduct that prohibit utilities’ transmission employees from providing non-public transmission information to the utility’s marketing employees. In addition, both the FERC and state regulators are permitted to review the books and records of any company within a holding company system. EPACT gives the FERC increased utility merger oversight.

Seasonality

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

GENERATION & MARKETING

Our Generation & Marketing segment subsidiaries consist of competitive nonutility generating assets, a wholesale energy trading and marketing business and a retail supply and energy management business. The largest subsidiary in our Generation & Marketing segment is AGR. On December 31, 2013, AGR acquired the generation assets and related liabilities at net book value of OPCo in a series of transactions approved by the PUCO and the FERC. AGR transferred a portion of the generation assets and liabilities at net book value that it received to APCo and KPCo. As a result of these transactions, AGR owns 10,002 MW of generating capacity, with rights to an additional 1,186 MW pursuant to a unit power agreement (see below). Other subsidiaries in this segment own or have the right to receive power from additional generation assets. See Item 2 – Properties for more information regarding the generation assets of the Generation & Marketing segment. AGR is a competitive generation subsidiary.

With respect to our wholesale energy trading and marketing business, we enter into short and long-term transactions to buy or sell capacity, energy and ancillary services primarily in ERCOT, MISO and PJM. We sell power into the market and engage in power, natural gas, coal and emissions allowances risk management and trading activities.

These activities primarily involve the purchase and sale of electricity (and to a lesser extent, natural gas, coal and emissions allowances) under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, over-the-counter swaps and options. The majority of forward contracts are typically settled by entering into offsetting contracts. These transactions are executed with numerous counterparties or on exchanges.

With respect to our retail supply and energy management business, our subsidiary AEP Energy is a retail electricity supplier that supplies electricity to residential, commercial, and industrial customers. AEP Energy provides an array of energy solutions and is operating in Illinois, Pennsylvania, Delaware, Maryland, New Jersey, Ohio and Washington, D.C. AEP Energy also provides demand-side management solutions nationwide. AEP Energy had approximately 215,000 customer accounts as of December 31, 2013.

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, third-party financings; review of mergers; and dispositions of jurisdictional facilities and acquisitions of securities of another public utility or an existing operational generating facility.

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

COMPETITION

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

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

Seasonality

The sale of electric power is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter months. The pattern of this fluctuation may change.

Counterparty Risk Management

Counterparties and exchanges may require cash or cash related instruments to be deposited on these transactions as margin against open positions. As of December 31, 2013, counterparties posted approximately $14 million in cash, cash equivalents or letters of credit with AEP for the benefit of AEP's generation and marketing subsidiaries (while, as of that date, AEP's generation and marketing subsidiaries posted approximately $165 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 2013 Annual Reports, under the heading entitled Quantitative and Qualitative Disclosures About Market Risk for additional information.

Fuel Supply

AEP's generation and marketing subsidiaries procure coal under a combination of purchasing arrangements including long-term contracts, affiliate operations and spot agreements with various producers and coal trading firms. Management believes that AEP's generation and marketing subsidiaries will be able to secure and transport coal of adequate quality and in adequate quantities to operate their coal-fired units. Through subsidiaries, AEP owns, leases or controls more than 5,700 railcars, approximately 600 barges and 15 towboats to move and store coal for use in our generating facilities.

Most of the coal purchased by AEP is procured through term contracts. As those contracts expire, they can be replaced at the new market price with an impact in subsequent periods. Several of AEP's natural gas-fired power plants are connected to at least two pipelines, which allows greater access to competitive supplies and improves delivery reliability. A portfolio of term, monthly, seasonal firm and daily peaking commodity and transportation agreements (that are entered into on a competitive basis and based on market prices) supplies natural gas requirements for each plant, as appropriate.

Certain Power Agreements

AEGCo

The Unit Power Agreement between AEGCo and AGR (assigned from OPCo) dated March 15, 2007, provides for the sale by AEGCo to AGR of all the capacity and associated unit contingent energy and ancillary services available to AGR from the Lawrenceburg Plant, a 1,186 MW natural gas-fired unit owned by AEGCo. AGR is obligated to pay a capacity charge (whether or not power is available from the Lawrenceburg Plant), and the fuel, operating and maintenance charges associated with the energy dispatched by AGR, and to reimburse AEGCo for other costs associated with the operation and ownership of the Lawrenceburg Plant. The agreement will continue in effect until December 31, 2017 unless extended.

OPCo

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

Other

As of December 31, 2013, the assets utilized in this segment included approximately 310 MW of company-owned domestic wind power facilities, 177 MW of domestic wind power from long-term purchase power agreements and 377

MW of coal-fired capacity which was obtained through an agreement effective through 2027 that transfers TNC's interest in the Oklaunion power station to AEP Energy Partners, Inc. The power obtained from the Oklaunion power station is marketed and sold in ERCOT.

AEP TRANSMISSION HOLDCO (AEPTHCO)

AEPTHCO OVERVIEW

AEPTHCo is a holding company for AEPTCo and for AEP's transmission joint ventures. AEPTCo is a holding company for seven wholly-owned FERC-regulated transmission-only electric utilities (Transcos), each of which is geographically aligned with our existing utility operating companies. 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 supply-side resources (primarily renewable) and retirements of generation facilities.

AEPTCo's seven Transcos are:

AEP East Transmission Companies (all located within PJM)

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

AEP West Transmission Companies (all located within SPP)

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

The Transcos develop, own and operate transmission assets that are physically connected to AEP's existing system. They are regulated for rate-making purposes exclusively by the FERC and employ a forward-looking formula rate tariff design. The Transcos are independent of but overlay AEP's existing vertically-integrated utility operating companies 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, OHTCo, OKTCo and WVTCo currently own and operate transmission assets or have assets under construction. Applications for regulatory approvals have been filed for SWTCo and are currently under consideration in Arkansas and Louisiana. As of December 31, 2013, AEPTCo had $991 million of transmission assets in-service with plans to construct nearly $2 billion of additional transmission assets through 2016.

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. Transource Energy, LLC (Transource) is a joint venture between AEPTHC (86.5%) and Great Plains Energy (13.5%). Transource was formed to pursue competitive projects resulting from FERC Order No. 1000 described further below under the heading Competition. Our other joint ventures are at various stages of regulatory and RTO approval.

We are currently participating in the following joint venture initiatives:

Project Name	Location	Projected Completion Date	Owners (Ownership %)	Total Estimated Project Costs at Completion	AEP's Investment at December 31, 2013 (h)	Approved Return on Equity
				(in thousands)		
ETT	Texas (ERCOT)	2023	MidAmerican Energy (50%) AEP (50%)	$ 3,057,000 (a)	$ 440,719	9.96 %
Prairie Wind	Kansas	2014	Westar Energy (50%) MidAmerican Energy (25%) (b) AEP (25%) (b)	170,000	11,533	12.8 %
Pioneer	Indiana	2018 (c)	Duke Energy (50%) AEP (50%)	1,100,000 (c)	2,466	12.54 %
RITELine IN	Indiana	2026	Exelon (12.5%) (d) AEP (87.5%) (d)	400,000	685 (e)	11.43 %
RITELine IL	Illinois	2026	Commonwealth Edison (75%) Exelon (12.5%) (d) AEP (12.5%) (d)	1,200,000	13 (e)	11.43 %
Transource Missouri	Missouri	2017	Great Plains Energy (13.5%) (f) AEP (86.5%) (f)	398,000 (g)	2,275	11.1 % (g)

(a) ETT's investment in completed, current and future projects in ERCOT over the next ten years is expected to be $3.057 billion. Future projects will be evaluated on a case-by-case basis.
(b) AEP owns 25% of Prairie Wind Transmission, LLC (Prairie Wind) through its ownership interest in ETA. ETA is a 50/50 joint venture with MidAmerican Energy and AEP.
(c)

The Pioneer project consists of approximately 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 $330 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 (AEPTHC). AEP owns 12.5% of RITELine Illinois, LLC (RITELine IL) through its ownership interest in RTD. RTD is a 50/50 joint venture with Exelon Transmission Company, LLC and AEPTHC.

(e) RITELine IN is a consolidated variable interest entity. RTD received an order from the FERC in October 2011 granting incentives for the RITELine IN and RITELine IL projects. The projects and other segments that are electrically equivalent in nature are currently under consideration for inclusion in the interregional planning process between PJM and MISO.

(f) AEP owns 86.5% of Transource Missouri through its ownership interest in Transource Energy, LLC (Transource). Transource is a joint venture with AEPTHC and Great Plains Energy formed to pursue competitive transmission projects. AEPTHC 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 $333 million Sibley-Nebraska City project (11.3%).

(h) RITELine IN and Transource Missouri 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.

In August 2012, the PJM board cancelled the Potomac-Appalachian Transmission Highline Project (PATH Project), our transmission joint venture with FirstEnergy, and removed it from the 2012 Regional Transmission Expansion Plan. In September 2012, the PATH Project companies submitted an application to the FERC requesting authority to recover prudently-incurred costs associated with the Project. In November 2012, the FERC issued an order accepting the PATH Project's abandonment cost recovery application, subject to settlement procedures and hearing. The settlement proceedings are on-going. AEP’s investment in the PATH Project as of December 31, 2013 was $25 million.

Our joint ventures do not have employees. Business services for the joint ventures are provided by AEPSC and other AEP subsidiaries and the joint venture partners.

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 Open Access Transmission Tariff (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. The formula rates establish rates for a one-year period based on the current projects in-service and proposed projects for a defined timeframe. The formula rates also include a true-up calculation for the previous year’s billings, allowing for over- and under-recovery of the transmission owner’s ATRR. PJM and SPP pay the transmission owners their ATRR for use of their facilities and bill transmission customers taking service under the PJM and SPP OATTs, based on the terms and conditions in the respective OATT for the service taken.

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

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

The Transcos collectively filed rate base totals of $776 million in 2013, $283 million for 2012 and $104 million for 2011. The total transmission revenue requirement filed in the ATRR for 2013, 2012 and 2011 was $99 million, $35 million and $13 million, respectively.

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

COMPETITION

One of the most significant provisions of FERC Order No. 1000 is the removal of the federal right of first refusal for incumbent utilities within tariffs and agreements for certain regional transmission projects. Historically, vertically integrated public utilities had the right to build and own transmission lines proposed by the region’s planning processes when those lines connected to facilities within their respective retail service territories. FERC Order No. 1000 eliminates the federal right of first refusal in regional transmission organization (RTO) tariffs for incumbent utilities to construct certain regional transmission projects within their own service territories, thereby creating the opportunity for any qualified entity to build and own regional transmission facilities in any service territory. Transource was created to respond to FERC Order No. 1000 competitive processes at the RTO level as described above.

AEP RIVER OPERATIONS

Our AEP River Operations segment transports liquid, coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi rivers. Almost all of our customers are nonaffiliated third parties who obtain the transport of coal and dry bulk commodities for various uses. We charge these customers market rates for the purpose of making a profit. Depending on market conditions and other factors, including barge availability, we permit AEP utility subsidiary affiliates to use certain of our equipment at rates that reflect our cost. Our affiliated utility customers procure the transport of coal for use as fuel in their respective generation plants. AEP River Operations includes approximately 2,300 barges, 36 towboats and 20 harbor boats that we own or lease. In 2014, River Operations will add at least 20 ten thousand barrel tank barges. Those barges will provide an entry into the tank barge business which will serve both current and new customers that transport liquid commodities. These assets are separate from the barges and towboats dedicated exclusively to transporting coal for use as fuel in our own generating facilities discussed under the prior segment. See Item 1 – Vertically Integrated Utilities – Electric Generation – Fuel Supply – Coal and Lignite.

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

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

EXECUTIVE OFFICERS OF AEP as of February 25, 2014

The following persons are executive officers of AEP. Their ages are given as of February 1, 2014. 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 53
Chairman of the Board since January 2014, President since January 2011 and Chief Executive Officer since November 2011. Was Executive Vice President-Generation from September 2006 to December 2010.

Lisa M. Barton
Executive Vice President – Transmission
Age 48
Executive Vice President-Transmission of AEPSC since August 2011. Was Senior Vice President-Transmission Strategy and Business Development of AEPSC from November 2010 to July 2011, Vice President-Transmission Strategy and Business Development of AEPSC from October 2007 to November 2010.

David M. Feinberg
Executive Vice President, General Counsel and Secretary
Age 44
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 53
Senior Vice President and Chief Administrative Officer since December 2012. Previously served as South Region leader-Senior Partner at Aon Hewitt since 2010. Was U.S. Consulting Client Development leader-managing principal at Aon Hewitt from 2008-2010.

Mark C. McCullough
Executive Vice President – Generation
Age 54
Executive Vice President-Generation of AEPSC since January 2011. Was Senior Vice President-Fossil & Hydro Generation of AEPSC from February 2008 to December 2010.

Robert P. Powers
Executive Vice President and Chief Operating Officer
Age 59
Executive Vice President and Chief Operating Officer since November 2011. Was President-Utility Group from April 2009 to November 2011, President-AEP Utilities from January 2008 to April 2009.

Brian X. Tierney
Executive Vice President and Chief Financial Officer
Age 46

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

Dennis E. Welch
Executive Vice President and Chief External Officer
Age 62
Executive Vice President and Chief External Officer since January 2013. Was Executive Vice President and Chief Administrative Officer from October 2011 to December 2012. Was Executive Vice President-Environment, Safety & Health and Facilities from January 2008 to September 2011.

ITEM 1A. RISK FACTORS

GENERAL RISKS OF OUR REGULATED OPERATIONS

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

Our business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades and retrofits, construction of additional transmission facilities, modernizing existing infrastructure as well as other initiatives. Our public utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. If these regulatory commissions do not approve adjustments to the rates we charge, we would not be able to recover the costs associated with our planned extensive investment. This would cause our financial results to be diminished.

Approval of the June 2012 through May 2015 ESP order in Ohio may be overturned and is subject to appeal. – Affecting AEP and OPCo

In August 2012, the PUCO issued an order which adopted and modified an ESP through May 2015 (the "2012 ESP"). The 2012 ESP allowed the continuation of the fuel adjustment clause, maintained recovery of several previous ESP riders and approved a storm damage recovery mechanism. The 2012 ESP further established (a) a non-bypassable Distribution Investment Rider effective September 2012 through May 2015 to recover certain distribution investment, and (b) a non-bypassable Retail Stability Rider (RSR), a portion of which provides for the collection of deferred capacity costs. The deferred capacity costs may exceed the amount we will collect under the RSR. In January 2013, the PUCO issued an order on rehearing for the 2012 ESP which generally upheld its prior order. Intervenors are challenging various parts of these orders at the PUCO and with the Supreme Court of Ohio. In parallel proceedings, the PUCO addressed certain issues around the energy auctions while other issues were deferred to a separate docket. The PUCO has agreed to issue a request for an independent auditor in the fuel adjustment clause proceeding to separately examine the recovery of the fixed fuel costs. If all or part of 2012 ESP is overturned by the PUCO or the Supreme Court of Ohio, or if deferred capacity and other costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Our request for an ESP from June 2015 through May 2018 may not be approved in its entirety. – Affecting AEP and OPCo

In December 2013, OPCo filed an application with the PUCO to approve an ESP that includes proposed rate adjustments and the continuation and modification of certain existing riders, effective June 2015 through May 2018. The proposal includes a return on common equity of 10.65% for certain riders. Additionally, the application identifies OPCo's intention to submit a separate application to continue the RSR in which the unrecovered portion of the deferred capacity costs will continue to be collected until the balance of the capacity deferrals has been collected. If the PUCO denies all or part of the requested ESP, it could reduce future net income and cash flows and impact financial condition.

Ohio may require us to refund revenue that we have collected. – Affecting AEP and OPCo

Ohio law requires that the PUCO determine on an annual basis if rate adjustments included in prior orders resulted in significantly excessive earnings. If the PUCO determines there were significantly excessive earnings, the excess amount could be returned to customers. In November 2013, OPCo filed its 2011 and 2012 significantly excessive earnings filings with the PUCO. If the PUCO determines that OPCo's earnings were significantly excessive, and requires OPCo to return a portion of its revenues to customers, it could reduce future net income and cash flows and impact financial condition.

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

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

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

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

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

In December 2012, SWEPCo placed the Turk Plant in Arkansas into commercial operation. SWEPCo holds a 73% ownership interest in the 600 MW coal-fired generating facility. SWEPCo had originally intended that the Arkansas jurisdictional share of the Turk Plant (approximately 20%) would become part of the rate base for its retail customers in Arkansas. Following a proceeding at the Arkansas Supreme Court, the APSC issued an order which reversed and set aside a previously granted Certificate of Environmental Compatibility and Public Need. The Arkansas portion of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the wholesale market. In addition, in February 2013, the LPSC granted recovery for the Louisiana portion of the Turk Plant costs in a formula rate filing, subject to refund based on the staff review of the cost of service and prudence review of the Turk Plant. If SWEPCo cannot recover all of its investment and expenses related to the Turk Plant either through retail rates or sales into the wholesale market, it could reduce future net income and cash flows and impact financial condition.

Request for rate recovery in Indiana may be overturned on appeal. – Affecting AEP and I&M

In February 2013, the IURC issued an order granting an annual increase in base rates. In March 2013, the Indiana Office of Utility Consumer Counselor (OUCC) filed an appeal of the order with the Indiana Court of Appeals. In September 2013, the OUCC filed a brief on appeal that included objections to certain aspects of the rate case. If any part of the order is overturned by the Indiana Court of Appeals, it could reduce future net income and cash flows.

Approved recovery related to enabling the useful life of the Cook Plant may be overturned on appeal or further consideration. – Affecting AEP and I&M

In April and May 2012, I&M filed petitions with the IURC and the MPSC, respectively, for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects for Cook Plant, Units 1 and 2 intended to ensure the safe and reliable operation of the plant through its extended licensed life (2034 for Unit 1 and 2037 for Unit 2). The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project. In February 2013, intervenors filed appeals with the Michigan Court of Appeals objecting to the issuance of the CON as well as the amount of the CON related to the LCM Project. In July 2013, the IURC approved I&M's proposed project apart from a minor exception which the IURC stated I&M could seek recovery in a base rate case. I&M was granted recovery through an LCM Project Rider to be determined in a series of proceedings beginning in the fourth quarter of 2013 and then semi-annually thereafter. If I&M is not ultimately permitted to recover its LCM Project costs, it could reduce future net income and cash flows and impact financial condition.

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

In July 2012, SWEPCo filed a request with the PUCT for an increase in Texas base rates. In October 2013, the PUCT issued an order that granted part of the requested rate recovery. Additionally, the PUCT determined that it would defer consideration of the requested increase in depreciation expense related to the change in the 2016 retirement date of the Welsh Plant, Unit 2. If SWEPCo cannot ultimately recover its Texas jurisdictional share of the investment and expenses related to the Turk Plant transmission lines or Welsh Plant, Unit 2, it could reduce future net income and cash flows and impact financial condition.

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

In January 2014, PSO filed a request with the OCC to increase annual base rates by $38 million, based upon a 10.5% return on common equity. If PSO cannot ultimately recover its costs that are the subject of this request, it could reduce future net income and cash flows and impact financial condition.

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

We expect that a growing portion of our earnings in the future will derive from the transmission investments and activities of AEPTCo and our transmission joint ventures. FERC policy currently favors the expansion and updating of the transmission infrastructure within its jurisdiction. If FERC were to adopt a different policy or if transmission needs do not continue or develop as projected, our strategy of investing in transmission could be curtailed. We believe our experience with transmission facilities construction and operation gives us an advantage over other competitors in securing authorization to install, construct and operate new transmission lines and facilities. However, there can be no assurance that PJM, SPP or other RTOs will authorize any new transmission projects or will award any such projects to us. If the FERC were to lower the rate of return it has authorized for our transmission investments and facilities, it could reduce future net income and cash flows and impact financial condition.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

We are involved in legal proceedings, claims and litigation arising out of our business operations, the most significant of which are summarized in Note 6 of the Combined Notes to Consolidated Financial Statements entitled Commitments, Guarantees and Contingencies. Adverse outcomes in these proceedings could require significant expenditures that could have a material adverse effect on our results of operations.

RISKS RELATING TO STATE RESTRUCTURING

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

Under current Ohio law, electric generation is sold in a competitive market in Ohio and native load customers in Ohio have the ability to switch to alternative suppliers for their electric generation service. CRES providers are targeting retail customers by offering alternative generation service. Through a short term agreement, AGR provides capacity and a decreasing portion of power to the Ohio customers that have not switched. As customer switching in Ohio continues, it could reduce AGR's future net income and cash flows and impact financial condition.

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

Our revenues from the distribution of electricity in the ERCOT area of Texas are collected from REPs that supply the electricity we distribute to their customers. Currently, we do business with approximately one hundred REPs. In 2013, TCC's largest REP accounted for 29% of its operating revenue and its second largest REP accounted for 16% of its operating revenue; TNC's largest REP accounted for 12% of its operating revenues and its second largest REP accounted for 7% of its operating revenues. Adverse economic conditions, structural problems in the Texas market or financial difficulties of one or more REPs could impair the ability of these REPs to pay for our services or could cause them to delay such payments. We depend on these REPs for timely remittance of payments. Any delay or default in payment could reduce future cash flows and impact financial condition.

RISKS RELATED TO OWNING AND OPERATING GENERATION ASSETS AND SELLING POWER

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

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. Approximately 90% of the electricity generated by the AEP System is produced by the combustion of fossil fuels. Emissions of nitrogen and sulfur oxides, mercury and particulates from fossil fueled generation plants are subject to increased regulations, controls and mitigation expenses. Compliance with these legal requirements requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees and permits at all of our facilities and could cause us to retire generating capacity prior to the end of its estimated useful life. These expenditures have been significant in the past and we expect that they will continue to be significant in order to comply with the current and proposed regulations. Costs of compliance with environmental regulations could reduce future net income and impact financial condition, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed and additional substances become regulated. If we retire generation plants prior to the end of their estimated useful life, there can be no assurance that we will recover the remaining costs associated with such plants. We typically recover our expenditures for pollution control technologies, replacement generation and associated operating costs from customers through regulated rates in regulated jurisdictions. Failure to recover these costs could reduce our future net income and cash flows and possibly harm our financial condition. For our sales of energy from our competitive units, there is no such cost-recovery mechanism. As a result, we may not recover our costs through the market and we may be forced to shut competitive units down. The costs of compliance for our competitive units could reduce our future net income and cash flows and possibly harm our financial condition.

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

The U.S. Congress has not taken any significant steps toward enacting legislation to control CO_2emissions since 2009. In December 2009, the Federal EPA issued a final endangerment finding under the CAA regarding emissions from motor vehicles. The Federal EPA also finalized CO_2 emission standards for new motor vehicles, and issued a rule that implements a permitting program for new and modified stationary sources of CO_2 emissions in a phased manner. Several groups have filed challenges to the endangerment finding and the Federal EPA's subsequent rulemakings. The Supreme Court has agreed to review whether EPA reasonably determined that establishing standards for new motor vehicles automatically triggered regulation of stationary sources through the prevention of significant deterioration and Title V permitting programs.

In 2012, the Federal EPA issued a proposed CO_2 emissions standard for new power generation sources with a CO_2 limit equivalent to a natural gas unit. In response to the comments submitted on this proposed rule, and in accordance with a directive from the President, EPA withdrew the April 2012 proposed rule and has issued a new proposal. This proposed rule includes separate, but equivalent, standards for natural gas and coal-fired units, based on the use of partial carbon capture and storage at coal units. We do not believe that carbon capture and storage has been adequately demonstrated, and intend to submit comments on the proposed rule. The President has also directed Federal EPA to issue standards for modified and reconstructed units, and a guideline for the development of state implementation plans that would reduce carbon emissions from existing utility units by June 2014, to finalize those standards by June 2015, and to require states to submit implementation plans no later than June 2016. Management believes some policy approaches being discussed would have significant and widespread negative consequences for the national economy and major U.S. industrial enterprises, including AEP and our customers.

If CO_2 and other emission standards are imposed, the standards could require significant increases in capital expenditures and operating costs which would impact the ultimate retirement of older, less-efficient, coal-fired units. We typically recover costs of complying with new requirements such as the potential CO_2 and other greenhouse gases emission standards from customers through regulated rates in regulated jurisdictions. For our sales of energy based on market rate authority, however, there is no such recovery mechanism. Failure to recover these costs, should they arise, could reduce our future net income and cash flows and possibly harm our financial condition.

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

At the end of last year, AGR acquired most of the generation formerly owned by OPCo. Recovery of AGR's generation capacity is subject to the results of annual PJM capacity auctions. Recent auction results indicate a great deal of volatility and the possibility of clearing prices substantially lower than the cost of such capacity. We formed a coalition with other utility companies to address mutual concerns related to the auction process and PJM has made filings with the FERC seeking modification of that process. Additional filings are expected. We can give no assurance that the FERC will approve any modifications to the annual PJM capacity auctions. If the annual PJM capacity auctions continue to result in clearing prices lower than the cost of our capacity, it could reduce our future net income and cash flows and impact financial condition.

Courts adjudicating nuisance and other similar claims against us may order us to pay damages or to limit or reduce our CO2 emissions. – Affecting each Registrant

In the past, there have been several cases seeking damages based on allegations of federal and state common law nuisance in which we, among others, were defendants. In general, the actions allege that CO2 emissions from the defendants' power plants constitute a public nuisance due to impacts of global warming and climate change. The plaintiffs in these actions generally seek recovery of damages and other relief. If the pending or other future actions are resolved against us, substantial modifications of our existing coal-fired power plants could be required and we might be required to limit or reduce CO2 emissions. Such remedies could require us to purchase power from third parties to fulfill our commitments to supply power to our customers. This could have a material impact on our costs. In addition, we could be required to invest significantly in additional emission control equipment, accelerate the timing of capital expenditures, pay damages or penalties and/or halt operations. While management believes such costs should be recoverable from customers as costs of doing business in our jurisdictions where generation rates are set on a cost of service basis, without such recovery those costs could reduce our future net income and cash flows and harm our financial condition. Moreover, our results of operations and financial position could be reduced due to the timing of recovery of these investments and the expense of ongoing litigation.

Changes in technology and regulatory policies may cause our generating facilities to be less competitive. – Affecting each Registrant

We primarily generate electricity at large central facilities. This method results in economies of scale and lower costs than newer technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in technologies or changes in regulatory policies will reduce costs of new technology to levels that are equal to or below that of most central station electricity production, which could have a material adverse effect on our results of operations.

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

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

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

We sell power from our generation facilities into the spot market and other competitive power markets on a contractual basis. We also enter into contracts to purchase and sell electricity, natural gas, emission allowances and coal as part of our power marketing and energy trading operations. With respect to such transactions, the rate of return on our capital investments is not determined through mandated rates, and our revenues and results of operations are likely to depend, in large part, upon pr