Appendix A to the
Proxy Statement

American Electric Power

2014 Annual Report

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

AMERICAN ELECTRIC POWER
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CONTENTS

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., an electric utility holding company.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, asset management and commercial and industrial sales in the deregulated Texas market.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a nonregulated AEP subsidiary in the Generation & Marketing segment.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
Appalachian Consumer Rate Relief Funding	Appalachian Consumer Rate Relief Funding LLC, a wholly-owned subsidiary of APCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to the under-recovered ENEC deferral balance.
ASU	Accounting Standards Update.
BlueStar	BlueStar Energy Holdings, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States. BlueStar began doing business as AEP Energy, Inc. in June 2012.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO_2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CRES 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.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel IV LLC, DCC Fuel V LLC, DCC Fuel VI LLC and DCC Fuel VII, consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
ENEC	Expanded Net Energy Charge.

Term	Meaning
Energy Supply	AEP Energy Supply LLC, a nonregulated holding company for AEP's competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IEU	Industrial Energy Users-Ohio.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo, which defined the sharing of costs and benefits associated with their respective generation plants. This agreement was terminated January 1, 2014.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWh	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate transactions among members of the Interconnection Agreement.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NSR	New Source Review.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
Ohio Phase-in-Recovery Funding	Ohio Phase-in-Recovery Funding LLC, a wholly-owned subsidiary of OPCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to phase-in recovery property.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.

Term	Meaning
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.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PCA	Power Coordination Agreement among APCo, I&M and KPCo.
PIRR	Phase-In Recovery Rider.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
POLR	Provider of Last Resort revenues.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, I&M, OPCo, PSO and SWEPCo.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A 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.
RPM	Reliability Pricing Model.
RSR	Retail Stability Rider.
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.
SEET	Significantly Excessive Earnings Test.
SIA	System Integration Agreement, effective June 15, 2000, as amended, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant, a 534 MW natural gas unit owned by SWEPCo.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Transition Funding	AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation.
Transource Energy	Transource Energy, LLC, a consolidated variable interest entity formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Transource Missouri	A 100% wholly-owned subsidiary of Transource Energy.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.

Term	Meaning
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

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

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

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

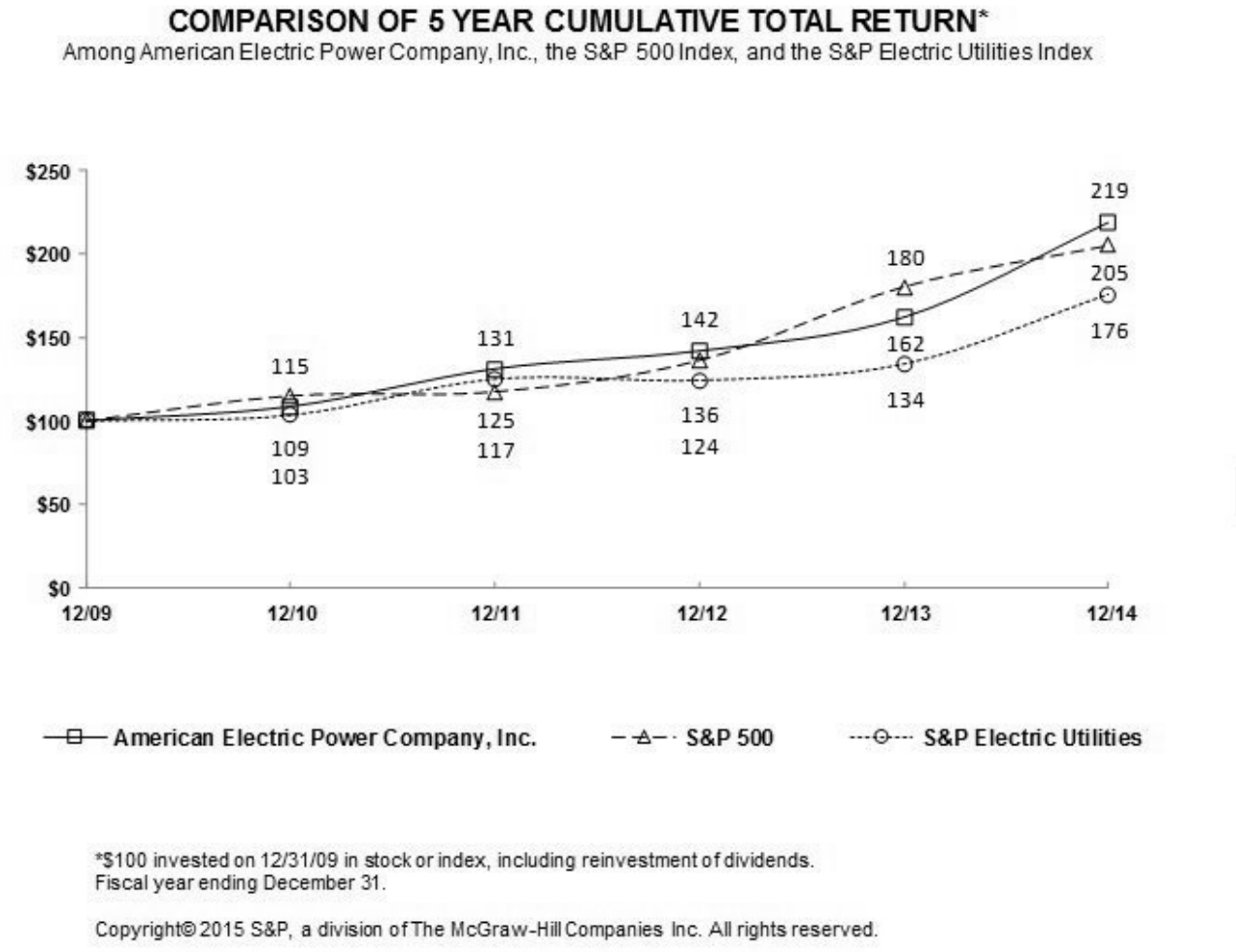
The forward looking statements of AEP and its Registrant Subsidiaries speak only as of the date of this report or as of the date they are made. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information. For a more detailed discussion of these factors,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

AEP COMMON STOCK AND DIVIDEND INFORMATION

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

Quarter Ended	High	Low	Quarter-End Closing Price	Dividend
December 31, 2014	$ 63.22	$ 51.97	$ 60.72	$ 0.53
September 30, 2014	55.91	49.06	52.21	0.50
June 30, 2014	55.94	49.99	55.77	0.50
March 31, 2014	50.95	45.80	50.66	0.50
December 31, 2013	$ 48.40	$ 43.01	$ 46.74	$ 0.50
September 30, 2013	47.59	41.83	43.35	0.49
June 30, 2013	51.60	42.83	44.78	0.49
March 31, 2013	48.68	42.92	48.63	0.47

AEP common stock is traded principally on the New York Stock Exchange. As of December 31, 2014, AEP had approximately 74,000 registered shareholders.



*$100 invested on 12/31/09 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

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

	2014	2013	2012	2011	2010
	(dollars in millions, except per share amounts)				
STATEMENTS OF INCOME DATA					
Total Revenues	$ 17,020	$ 15,357	$ 14,945	$ 15,116	$ 14,427
Operating Income	$ 3,232	$ 2,855	$ 2,656	$ 2,782	$ 2,663
Income Before Extraordinary Items	$ 1,638	$ 1,484	$ 1,262	$ 1,576	$ 1,218
Extraordinary Items, Net of Tax	—	—	—	373	—
Net Income	1,638	1,484	1,262	1,949	1,218
Net Income Attributable to Noncontrolling Interests	4	4	3	3	4
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,634	1,480	1,259	1,946	1,214
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	—	—	—	5	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,634	$ 1,480	$ 1,259	$ 1,941	$ 1,211
BALANCE SHEETS DATA					
Total Property, Plant and Equipment	$ 64,305	$ 60,285	$ 57,454	$ 55,670	$ 53,740
Accumulated Depreciation and Amortization	20,188	19,288	18,691	18,699	18,066
Total Property, Plant and Equipment – Net	$ 44,117	$ 40,997	$ 38,763	$ 36,971	$ 35,674
Total Assets	$ 59,633	$ 56,414	$ 54,367	$ 52,223	$ 50,455
Total AEP Common Shareholders' Equity	$ 16,820	$ 16,085	$ 15,237	$ 14,664	$ 13,622
Noncontrolling Interests	$ 4	$ 1	$ —	$ 1	$ —
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ —	$ —	$ —	$ —	$ 60
Long-term Debt (a)	$ 18,684	$ 18,377	$ 17,757	$ 16,516	$ 16,811
Obligations Under Capital Leases (a)	$ 552	$ 538	$ 449	$ 458	$ 474
AEP COMMON STOCK DATA					
Basic Earnings per Share Attributable to AEP Common Shareholders:					
Income Before Extraordinary Items	$ 3.34	$ 3.04	$ 2.60	$ 3.25	$ 2.53
Extraordinary Items, Net of Tax	—	—	—	0.77	—
Total Basic Earnings per Share Attributable to AEP Common Shareholders	$ 3.34	$ 3.04	$ 2.60	$ 4.02	$ 2.53
Weighted Average Number of Basic Shares Outstanding (in millions)	489	487	485	482	479
Market Price Range:					
High	$ 63.22	$ 51.60	$ 45.41	$ 41.71	$ 37.94
Low	$ 45.80	$ 41.83	$ 36.97	$ 33.09	$ 28.17
Year-end Market Price	$ 60.72	$ 46.74	$ 42.68	$ 41.31	$ 35.98
Cash Dividends Declared per AEP Common Share	$ 2.03	$ 1.95	$ 1.88	$ 1.85	$ 1.71
Dividend Payout Ratio	60.78%	64.14%	72.31%	46.02%	67.59%
Book Value per AEP Common Share	$ 34.37	$ 32.98	$ 31.35	$ 30.36	$ 28.32

(a) Includes portion due within one year.

EXECUTIVE OVERVIEW

Company Overview

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

Our subsidiaries operate an extensive portfolio of assets including:

- Approximately 37,600 megawatts of generating capacity, one of the largest complements of generation in the United States.
- Approximately 40,000 miles of transmission lines, including 2,110 miles of 765 kV lines, the backbone of the electric interconnection grid in the Eastern United States.
- Approximately 222,000 miles of distribution lines that deliver electricity to 5.3 million customers.
- Substantial commodity transportation assets (approximately 4,990 railcars, approximately 2,800 barges, 47 towboats, 20 harbor boats and a coal handling terminal with approximately 18 million tons of annual capacity). Our commercial barging operations annually transport approximately 48 million tons of coal and dry bulk commodities. Approximately 35% of the barging is for transportation of agricultural products, 34% for coal, 17% for steel and 14% for other commodities.

Customer Demand

In comparison to 2013, our weather-normalized retail sales increased 1% for the year ended December 31, 2014. Our 2014 industrial sales increased 0.4% compared to 2013, despite the closure of Ormet, a large aluminum company in October 2013. Excluding Ormet, our industrial sales volumes increased by 3.9%. Our 2014 residential and commercial sales increased 1.1% and 1.7%, respectively, compared to 2013.

In 2015, we anticipate weather-normalized retail sales will increase by 0.6%. The industrial class is expected to grow by 2% in 2015, primarily related to a number of new oil and natural gas expansions, especially around the major shale gas areas within AEP's footprint. Weather-normalized residential sales are projected to increase by 0.2%, primarily related to projected customer growth. Commercial class energy sales are projected to decrease by 0.4%.

Corporate Separation

Background

On December 31, 2013, as approved by the FERC and the PUCO, OPCo transferred its generation assets and related generation liabilities at net book value to AGR. In accordance with Ohio law, OPCo remains responsible to provide power and capacity to OPCo customers who have not switched electric providers. Effective January 1, 2014, OPCo began purchasing power from both affiliated and nonaffiliated entities, subject to PUCO approval, to meet the energy and capacity needs of customers. On December 31, 2013, subsequent to the transfer of OPCo's generation assets and associated liabilities to AGR, AGR transferred at net book value its ownership (867 MW) in Amos Plant, Unit 3 to APCo and one-half of its interest (780 MW) in the Mitchell Plant to KPCo.

Other Impacts of Corporate Separation

The Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated.

Effective January 1, 2014, the FERC approved the following:

- A PCA among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources.
- A Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent to address open commitments related to the termination of the Interconnection Agreement and responsibilities to PJM.
- A Power Supply Agreement between AGR and OPCo for AGR to supply capacity for OPCo's switched (at $188.88/MW day) and non-switched retail load for the period January 1, 2014 through May 31, 2015 and to supply the energy needs of OPCo's non-switched retail load that was not acquired through auctions in 2014.

For a further discussion of corporate separation, see the "Corporate Separation" section of Note 1.

Merchant Fleet Alternatives

AEP is evaluating strategic alternatives for its merchant generation fleet, which primarily includes AGR's generation fleet and AEG's Lawrenceburg unit which operates in PJM as well as a 54.7% interest in the Oklaunion Plant which operates in ERCOT. Potential alternatives may include, but are not limited to, continued ownership of the merchant generation fleet, executing a purchased power agreement with a regulated affiliate for certain merchant generation units in Ohio, a spin-off of the merchant generation fleet or a sale of the merchant generation fleet. Management has not made a decision regarding the potential alternatives, nor has management set a specific time frame for a decision. Certain of these alternatives could result in a loss which could reduce future net income and cash flow and impact financial condition.

Merchant Portion of Turk Plant

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

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the SWEPCo Arkansas jurisdictional share of the Turk Plant (approximately 20%). Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. In June 2010, in response to an Arkansas Supreme Court decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the wholesale market. Approximately 80% of the Turk plant is recovered under cost-based rate recovery in Texas, Louisiana, and through SWEPCo's wholesale customers.

If SWEPCo cannot ultimately recover its investment and expenses related to the Turk Plant, it could reduce future net income and cash flows and impact financial condition.

Ohio Electric Security Plan Filings

2009 - 2011 ESP

In August 2012, the PUCO issued an order in a separate proceeding which implemented a PIRR to recover OPCo's deferred fuel costs in rates beginning September 2012. Oral arguments at the Supreme Court of Ohio were held in February 2015. OPCo presented arguments to reinstate a weighted average cost of capital carrying charge and to defend against an intervenor argument that the carrying charges should be reduced due to an accumulated deferred income tax credit.

June 2012 - May 2015 Ohio ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that establishes base generation rates through May 2015. This ruling was generally upheld in PUCO rehearing orders in January and March 2013.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the RPM price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The OPCo RPM price collected from CRES providers, which includes reserve margins, was approximately $34/MW day through May 2014 and is $150/MW day from June 2014 through May 2015. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio.

As part of the August 2012 ESP order, the PUCO established a non-bypassable RSR, effective September 2012. The RSR was collected from customers at $3.50/MWh through May 2014 and is currently collected at $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. In April and May 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO's ESP order, including the RSR. As of December 31, 2014, OPCo's incurred deferred capacity costs balance was $422 million, including debt carrying costs.

In November 2013, the PUCO issued an order approving OPCo's competitive bid process with modifications. As ordered, in 2014, OPCo conducted multiple energy-only auctions for a total of 100% of the SSO load with delivery beginning April 2014 through May 2015. For delivery starting in June 2015, OPCo will conduct energy and capacity auctions for its entire SSO load. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings. Management believes that these intervenor concerns are without merit.

In January 2014, the PUCO denied all rehearing requests and agreed to issue a supplemental request for an independent auditor in the 2012 - 2013 FAC proceeding to separately examine the recovery of the fixed fuel costs, including OVEC. In March 2014, the PUCO approved OPCo's request to implement riders related to the unbundling of the FAC. In October 2014, the independent auditor, selected by the PUCO, filed its report for the period August 2012 through May 2015 with the PUCO. If the PUCO ultimately concludes that a portion of the fixed fuel costs are also recovered through OPCo's $188.88 capacity charge, the independent auditor recommends a methodology for calculating a refund of a portion of certain fixed fuel costs. The retail share of these fixed fuel costs is approximately $90 million annually. A hearing related to this matter has not been scheduled. Management believes that no over-recovery of costs has occurred and intends to oppose the findings in the audit report.

If OPCo is ultimately not permitted to fully collect all components of its ESP rates, it could reduce future net income and cash flows and impact financial condition.

Proposed June 2015 - May 2018 ESP

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 included a return on common equity of 10.65% on capital costs for certain riders and estimates an average decrease in rates of 9% over the three-year term of the plan for customers who receive their RPM capacity and energy auction-based generation through OPCo. The proposal also included a purchased power agreement (PPA) rider that would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based purchase power agreement. In May 2014, intervenors and the PUCO staff filed testimony that provided various recommendations including the rejection and/or modification of various riders, including the Distribution Investment Rider and the proposed PPA. Hearings at the PUCO in the ESP case were held in June 2014.

In July 2014, OPCo submitted a separate application to continue the RSR established in the June 2012 - May 2015 ESP to collect the unrecovered portion of the deferred capacity costs at the rate of $4.00/MWh, until the balance of the capacity deferrals has been collected.

In October 2014, OPCo filed a separate application with the PUCO to propose a new extended PPA for inclusion in the PPA rider, discussed above. The new PPA would include an additional 2,671 MW to be purchased from AGR over the life of the respective generating units.

If OPCo is ultimately not permitted to fully collect all components of its ESP rates, it could reduce future net income and cash flows and impact financial condition. See "Ohio Electric Security Plan Filings" section of Note 4.

2012 Texas Base Rate Case

Upon rehearing in January 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, in the fourth quarter of 2013, SWEPCo reversed $114 million of previously recorded regulatory disallowances. The resulting annual base rate increase is approximately $52 million. In May 2014, intervenors filed appeals of the order with the Texas District Court. In June 2014, SWEPCo intervened in those appeals and filed initial responses. If certain parts of the PUCT order are overturned it could reduce future net income and cash flows and impact financial condition. See the "2012 Texas Base Rate Case" section of Note 4.

2012 Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share of the Turk Plant. In February 2013, a settlement was approved by the LPSC that increased Louisiana total rates by approximately $2 million annually, effective March 2013. The March 2013 base rates are based upon a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover non-fuel Turk Plant costs and a full weighted-average cost of capital return on the prudently incurred Turk Plant investment in jurisdictional rate base, effective January 2013. In December 2014, the LPSC approved a settlement agreement related to the staff review of the cost of service. The settlement agreement reduced the requested revenue increase by $3 million, primarily due to the timing of both the allowed recovery of certain existing regulatory assets and the establishment of a regulatory asset for certain previously expensed costs. See the "2012 Louisiana Formula Rate Filing" section of Note 4.

2014 Oklahoma Base Rate Case

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. This revenue increase included a proposed increase in depreciation rates of $29 million. In addition, the filing proposed recovery of advanced metering costs through a separate rider over a three-year deployment period requesting $7 million of revenues in year one, increasing to $28 million in year three. The filing also proposed expansion of an existing transmission rider currently recovered in base rates to include additional transmission-related costs that are expected to increase over the next several years.

In June 2014, a non-unanimous stipulation agreement between PSO, the OCC staff and certain intervenors was filed with the OCC. The parties to the stipulation recommended no overall change to the transmission rider or to annual revenues, other than additional revenues through a separate rider related to advanced metering costs, and that the terms of the stipulation be effective November 2014. The advanced metering rider would provide $24 million of revenues over 14 months beginning in November 2014 and increase to $27 million in 2016. New depreciation rates are recommended for advanced metering investments and existing meters, also to be effective November 2014. Additionally, the stipulation recommends recovery of regulatory assets for 2013 storms and regulatory case expenses. In July 2014, the Attorney General joined in the stipulation agreement. In October 2014, the Administrative Law Judge (ALJ) recommended approval of the stipulation agreement and interim rates were implemented in November 2014, subject to refund. In November 2014, intervenors filed exceptions to the ALJ's report. An order is anticipated in the first quarter of 2015. If the OCC were to disallow any portion of this settlement agreement, it could reduce future net income and cash flows and impact financial condition. See the "2014 Oklahoma Base Rate Case" section of Note 4.

2014 Virginia Biennial Base Rate Case

In March 2014, APCo filed a biennial generation and distribution base rate case with the Virginia SCC. In accordance with a Virginia statute, APCo did not request an increase in base rates as its Virginia retail combined rate of return on common equity for 2012 and 2013 was within the statutory range of the approved return on common equity of 10.9%. The filing included a request to decrease generation depreciation rates, effective February 2015, primarily due to the change in the expected service life of certain plants. Additionally, the filing included a request to amortize $7 million annually for two years, beginning February 2015, related to IGCC and other deferred costs. APCo also requested approval to amortize $38 million related to an accumulated deferred Virginia state income tax (ADVSIT) liability over 20 years, beginning February 2015.

In November 2014, the Virginia SCC issued an order concluding that APCo's adjusted earned rate of return on common equity for 2012 and 2013, reflecting their ordered adjustments, was above the allowed threshold. The order included (a) a $6 million refund to customers for the years 2012 through 2013, (b) the write-off of $10 million of IGCC pre-construction costs, (c) approval to amortize a $38 million ADVSIT liability over 20 years, beginning February 2015 and (d) no change to generation depreciation rates with rates to be reviewed again in the next biennial rate case. The order also approved a new return on common equity of 9.7% effective for 2014 and 2015. The Virginia SCC did not rule on a Virginia SCC staff recommendation to write-down certain costs, for ratemaking purposes, for the biennial period based on APCo's earnings within the statutory equity range. In January 2015, the Virginia SCC initiated a separate proceeding to address the proper treatment of APCo's authorized regulatory assets. If any of these costs, or any additional costs that may be subject to review, are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the "2014 Virginia Biennial Base Rate Case" section of Note 4.

Potential New Virginia Legislation Affecting Biennial Reviews

In February 2015, amendments to Virginia law governing the regulation of investor-owned electric utilities were approved by the Virginia General Assembly and have been sent to the Governor. If these amendments are enacted, APCo's existing generation and distribution base rates would freeze until after the Virginia SCC rules on APCo's next biennial review, which APCo would file in March 2020 for the 2018 and 2019 test years. These amendments would also preclude the Virginia SCC from performing biennial reviews of APCo's earnings for the years 2014 through 2017. Management continues to monitor this potential new legislation in Virginia.

2014 West Virginia Base Rate Case

In June 2014, APCo filed a request with the WVPSC to increase annual base rates by $181 million, based upon a 10.62% return on common equity, to be effective in the second quarter of 2015. The filing included a request to increase generation depreciation rates primarily due to the increase in plant investment and changes in the expected service lives of various generating units. The filing also requested recovery of $89 million over five years related to 2012 West Virginia storm costs, IGCC and other deferred costs. In addition to the base rate request, the filing also included a request to implement a rider of approximately $45 million annually to recover vegetation management costs, including

a return on capital investment. In December 2014 and January 2015, intervenors filed testimony which proposed total annual revenue increases ranging from $35 million to $59 million based upon returns on common equity ranging from 9% to 10% and regulatory asset disallowances ranging from $7 million to $9 million. Additionally, other intervenors proposed that the revenue requirement be based on a return on common equity of 8.7% and that $89 million of regulatory assets be disallowed. Intervenors also recommended a disallowance of approximately $44 million related to the December 2013 transfer of OPCo's two-thirds interest in the Amos Plant, Unit 3 to APCo. Hearings at the WVPSC were held in January 2015. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the "2014 West Virginia Base Rate Case" section of Note 4.

Plant Transfer

APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a cost-of-service basis, to their respective customers. West Virginia generally allows for timely recovery of fuel costs through an expanded net energy cost which trues-up to actual expenses. In March 2014, APCo and WPCo filed a request with the WVPSC for approval to transfer at net book value to WPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity presently owned by AGR. In April 2014, APCo and WPCo filed testimony that supported their request and proposed a base rate surcharge of $113 million, to be offset by an equal reduction in the ENEC revenues, to be effective upon the transfer of the Mitchell Plant to WPCo. In June 2014, the FERC issued an order approving a request by AGR and WPCo to transfer AGR's one-half interest in the Mitchell Plant to WPCo.

In October 2014, a stipulation agreement between APCo, WPCo, the WVPSC staff and intervenors in the case was filed with the WVPSC. The stipulation agreement recommended approval for WPCo to acquire, at net book value, the one-half interest in the Mitchell Plant, excluding certain assets, and to pay AGR $20 million upon transfer, which WPCo will record as a regulatory asset, include in rate base and recover over the life of the plant. Additionally, the agreement stated that 82.5% of the costs associated with the acquired interest will be reflected in rates effective from the date of the transfer via a surcharge with an offset in ENEC revenues of $93 million. The remaining 17.5% of the costs associated with the acquired interest is to be included in rates by January 2020. The agreement also proposed that WPCo share the energy margins for 82.5% of the plant's output with ratepayers and that WPCo retain all of the energy margins from sales into the wholesale market on the remaining 17.5%, to offset fixed costs associated with this portion, until the remaining portion is included in rates. In December 2014, the WVPSC issued an order that approved the settlement agreement, subject to certain modifications related to 82.5% of the energy and capacity margin sharing. The WVPSC determined that the sharing mechanism that was proposed is reasonable and will be adopted provided the result of the sharing mechanism will be adjusted, if necessary, so that the sharing mechanism does not result in a net cost to ratepayers that exceeds the actual variable cost of generation. In January 2015, the transfer of the one-half interest in the Mitchell Plant to WPCo was completed. See the "Plant Transfer" section of APCo Rate Matters in Note 4.

Kentucky Fuel Adjustment Clause Review

In August 2014, the KPSC issued an order initiating a review of KPCo's FAC from November 2013 through April 2014. In January 2015, the KPSC issued an order disallowing certain FAC costs during the period of January 2014 through May 2015 while KPCo owns and operates both Big Sandy Plant, Unit 2 and its one-half interest in the Mitchell Plant. Additionally, the KPSC directed KPCo to refund to customers $13 million of fuel costs, by the end of the second quarter of 2015, collected during the FAC review period of January 2014 through April 2014. As a result of this order, KPCo recorded a regulatory disallowance of $36 million in December 2014. In February 2015, KPCo filed an appeal of this order with the Franklin County Circuit Court.

2014 Kentucky Base Rate Case

In December 2014, KPCo filed a request with the KPSC for an increase in rates of $70 million, which consists of a $75 million increase in rider rates, offset by a $5 million decrease in annual base rates, to be effective July 2015. The net increase reflects KPCo's ownership interest in the Mitchell Plant, riders to recover the Big Sandy Plant retirement and operational costs and the inclusion of an environmental compliance plan related to the Mitchell Plant FGD. Additionally, the filing included a request to recover deferred storm costs. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

PJM Capacity Auction

AGR is required to offer all of its available generation capacity in the PJM RPM auction, which is conducted three years in advance of the actual delivery year.

Through May 2015, AGR will provide generation capacity to OPCo for both switched and non-switched OPCo generation customers. For switched customers, OPCo pays AGR $188.88/MW day for capacity. For non-switched OPCo generation customers, OPCo pays AGR its blended tariff rate for capacity consisting of $188.88/MW day for auctioned load and the non-fuel generation portion of its base rate for non-auctioned load. AGR's excess capacity is subject to the PJM RPM auction. After May 2015, AGR's generation assets will be subject to PJM capacity prices. Shown below are the current auction prices for capacity, as announced/settled by PJM:

PJM Auction Period	PJM Base Auction Price (per MW day)
June 2013 through May 2014	$ 27.73
June 2014 through May 2015	125.99
June 2015 through May 2016	136.00
June 2016 through May 2017	59.37
June 2017 through May 2018	120.00

We expect a significant decline in AGR capacity revenues after May 2015 when the Power Supply Agreement between AGR and OPCo ends. We expect a further decline in AGR capacity revenues from June 2016 through May 2017 based upon the decrease in the PJM base auction price.

In conjunction with other utility companies, we continue to address mutual concerns related to the PJM capacity auction process. Through this advocacy effort, the FERC has accepted PJM recommendations which should have the impact of reducing capacity price volatility beginning in the June 2018 time period.

In December 2014, PJM filed with FERC for approval of a new type of capacity product, the Capacity Performance Product. The intent of the filing is to raise the level of capacity performance and reliability during emergency events by: (a) assessing higher penalties for non-performance during these events, (b) allowing higher price offers into the auction and (c) requiring generating units to provide fuel and operational assurances that they can perform reliably during emergency events.

In this same filing, PJM proposed with FERC supplemental capacity auctions for the June 2016 through May 2017 and June 2017 through May 2018 auction periods. These supplemental auctions would address capacity performance and reliability issues in these interim years, and if accepted, would allow AGR to re-offer at least part of the capacity already cleared for these years at a higher price. A FERC order is expected in the first half of 2015.

Welsh Plant, Units 1 and 3 - Environmental Projects

To comply with pending Federal EPA regulations, SWEPCo is currently constructing environmental control projects to meet mercury and air toxics standards for Welsh Plant, Units 1 and 3 at a cost of approximately $410 million, excluding AFUDC. Management currently estimates that the total environmental projects to be completed through 2020 for Welsh Plant, Units 1 and 3 will cost approximately $600 million, excluding AFUDC. As of December 31, 2014, SWEPCo has incurred costs of $164 million and has remaining contractual construction obligations of $108 million related to these projects. SWEPCo will seek recovery of these project costs from customers through filings at the state commissions and the FERC. See "Climate Change, CO_2 Regulation and Energy Policy" section of "Environmental Issues" below. As of December 31, 2014, the net book value of Welsh Plant, Units 1 and 3 was $388 million, before cost of removal, including materials and supplies inventory and CWIP. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

LITIGATION

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. We assess the probability of loss for each contingency and accrue a liability for cases that have a probable likelihood of loss if the loss can be estimated. For details on our regulatory proceedings and pending litigation see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

Rockport Plant Litigation

In July 2013, the Wilmington Trust Company filed a complaint in U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiff further alleges that the defendants' actions constitute breach of the lease and participation agreement. The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff. The New York court has granted our motion to transfer this case to the U.S. District Court for the Southern District of Ohio. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M. In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiffs' claims. Several claims remain, including the claim for breach of the participation agreement and a claim alleging breach of an implied covenant of good faith and fair dealing. We will continue to defend against the remaining claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

ENVIRONMENTAL ISSUES

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

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

We will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. Environmental rules could result in accelerated depreciation, impairment of assets or regulatory disallowances. If we are unable to recover the costs of environmental compliance, it would reduce future net income and cash flows and impact financial condition.

Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed in the next several sections will have a material impact on the generating units in the AEP System. We continue to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of December 31, 2014, the AEP System had a total generating capacity of nearly 37,600 MWs, of which over 23,700 MWs are coal-fired. We continue to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on our coal-fired generating facilities. Based upon our estimates, additional investment to meet these proposed requirements ranges from approximately $2.8 billion to $3.3 billion through 2020. These amounts include investments to convert some of our coal generation to natural gas. If natural gas conversion is not completed, these units could be retired sooner than planned.

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

Subject to the factors listed above and based upon our continuing evaluation, we intend to retire the following plants or units of plants before or during 2016:

Company	Plant Name and Unit	Generating Capacity (in MWs)
AGR	Kammer Plant	630
AGR	Muskingum River Plant	1,440
AGR	Picway Plant	100
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
APCo/AGR	Sporn Plant	600
I&M	Tanners Creek Plant	995
KPCo	Big Sandy Plant, Unit 2	800
PSO	Northeastern Station, Unit 4	470
SWEPCo	Welsh Plant, Unit 2	528
Total		6,533

As of December 31, 2014, the net book value of the AGR units listed above was zero. The net book value, before cost of removal, including related material and supplies inventory and CWIP balances, of the regulated plants in the table above was $980 million. See Note 5 for further discussion.

In addition, we are in the process of obtaining permits following the KPSC's approval for the conversion of KPCo's 278 MW Big Sandy Plant, Unit 1 to natural gas. As of December 31, 2014, the net book value, before cost of removal, including related material and supplies inventory and CWIP balances of Big Sandy Plant, Unit 1 was $114 million.

Volatility in fuel prices, pending environmental rules and other market factors could also have an adverse impact on the accounting evaluation of the recoverability of the net book values of coal-fired units. For regulated plants that we may close early, we are seeking regulatory recovery of remaining net book values. To the extent the book value of existing generation assets and the cost of new equipment and converted facilities are not recoverable, it could materially reduce future net income and cash flows and impact financial condition.

Clean Air Act Requirements

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

The Federal EPA issued the Clean Air Interstate Rule (CAIR) in 2005 requiring specific reductions in SO_2 and NO_x emissions from power plants. The Federal EPA issued the Cross-State Air Pollution Rule (CSAPR) in August 2011 to replace CAIR. The CSAPR was challenged in the courts. In 2012, a panel of the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing CAIR until a replacement rule is finalized. That decision was appealed to the U.S. Supreme Court, which reversed the decision and remanded the case to the U.S. Court of Appeals for the District of Columbia Circuit. All of the states in which our power plants are located are covered by CSAPR. See "Cross-State Air Pollution Rule (CSAPR)" section below.

The Federal EPA issued the final maximum achievable control technology (MACT) standards for coal and oil-fired power plants in 2012. See "Mercury and Other Hazardous Air Pollutants (HAPs) Regulation" section below.

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

In 2009, the Federal EPA issued a final mandatory reporting rule for CO_2 and other greenhouse gases covering a broad range of facilities emitting in excess of 25,000 tons of CO_2 emissions per year. The Federal EPA issued a final endangerment finding for greenhouse gas emissions from new motor vehicles in 2009. The Federal EPA determined that greenhouse gas emissions from stationary sources will be subject to regulation under the CAA beginning January 2011 and finalized its proposed scheme to streamline and phase-in regulation of stationary source CO_2 emissions through the NSR prevention of significant deterioration and Title V operating permit programs through the issuance of final federal rules, SIP calls and FIPs. The Federal EPA has proposed to include CO_2 emissions in standards that apply to new and existing electric utility units. See "Climate Change, CO_2 Regulation and Energy Policy" section below.

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

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

Cross-State Air Pollution Rule (CSAPR)

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

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit. In 2012, the court issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the CAIR until a replacement rule is finalized. The majority determined that the CAA does not allow the Federal EPA to "overcontrol" emissions in an upwind state and that the Federal EPA exceeded its statutory authority by failing to allow states an opportunity to develop their own implementation plans before issuing a FIP. The petition for review filed by the Federal EPA and other parties in the U.S. Supreme Court was granted in June 2013. In April 2014, the U.S. Supreme Court issued a decision reversing in part the decision of the U.S. Court of Appeals for the District of Columbia Circuit and remanding the case for further proceedings consistent with the opinion. The Federal EPA filed a motion to lift the stay and allow Phase I of CSAPR to take effect on January 1, 2015 and Phase II to take effect on January 1, 2017. The court granted the Federal EPA's motion, established a briefing schedule and scheduled oral argument for March 2015 on the remaining issues. Separate appeals of the Error Corrections Rule and the further revisions have been filed but no briefing schedules have been established. We cannot predict the outcome of the pending litigation.

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for mercury, PM (as a surrogate for particles of nonmercury metals) and hydrogen chloride (as a surrogate for acid gases) for units burning coal on a site-wide 30-day rolling average basis. In addition, the rule proposes work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. The effective date of the final rule was April 16, 2012 and compliance is required within three years. Petitions for administrative reconsideration and judicial review were filed. In 2012, the Federal EPA published a notice announcing that it would accept comments on its reconsideration of certain issues related to the new source standards, including clarification of the requirements that apply during periods of start-up and shut down, measurement issues and the application of variability factors that may have an impact on the level of the standards. The Federal EPA issued revisions to the new source standards consistent with the proposed rule, except the start-up and shut down provisions in March 2013. The Federal EPA is still considering additional changes to the start-up and shut down provisions. In April 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the April 2012 final rule. Industry trade groups and several states filed petitions for further review in the U.S. Supreme Court and the court granted those petitions in November 2014.

The final rule contains a slightly less stringent PM limit for existing sources than the original proposal and allows operators to exclude periods of start-up and shut down from the emissions averaging periods. We have obtained a one-year administrative extension at several units to facilitate the installation of controls or to avoid a serious reliability problem. In addition, the Federal EPA issued an enforcement policy describing the circumstances under which an administrative consent order might be issued to provide a fifth year for the installation of controls or completion of reliability upgrades. We remain concerned about the availability of compliance extensions, the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines and the lack of coordination among the Mercury and Air Toxics Standards schedule and other environmental requirements.

Climate Change, CO_2 Regulation and Energy Policy

National public policy makers and regulators in the 11 states we serve have diverse views on climate change, carbon regulation and energy policy. We are currently focused on responding to these emerging views with prudent actions across a range of plausible scenarios and outcomes. We are active participants in both state and federal policy development to assure that any proposed new requirements are feasible and the economies of the states we serve are not placed at a competitive disadvantage.

Several states have adopted programs that directly regulate CO_2 emissions from power plants. The majority of the states where we have generating facilities have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements that can assist in reducing carbon emissions. We are taking steps to comply with these requirements, including increasing our wind power purchases and broadening our portfolio of energy efficiency programs.

We estimate that our 2014 emissions were approximately 120 million metric tons. This represents a reduction of 18% compared to our 2005 CO_2 emissions of approximately 146 million metric tons.

In the absence of comprehensive federal climate change or energy policy legislation, President Obama issued a memorandum to the Administrator of the Federal EPA directing the agency to develop and issue a new proposal regulating carbon emissions from new electric generating units under the CAA. The new proposal was issued in September 2013 and requires new large natural gas units to meet a limit of 1,000 pounds of CO_2 per MWh of electricity generated and small natural gas units to meet a limit of 1,100 pounds of CO_2 per MWh. New coal-fired units are required to meet a limit of 1,100 pounds of CO_2 per MWh, with the option to meet a 1,000 pound per MWh limit if they choose to average emissions over multiple years. This proposal was published in the Federal Register in January 2014 and the comment period has closed.

The Federal EPA was also directed to develop and issue a separate proposal regulating carbon emissions from modified and reconstructed electric generating units (EGUs) and to issue guidelines for existing EGUs before June 2014, to finalize those standards by June 2015 and to require states to submit revisions to their implementation plans including such standards no later than June 2016. The Federal EPA issued guidelines for the development of standards for existing sources in June 2014. The guidelines use a "portfolio" approach to reducing emissions from existing sources that includes efficiency improvements at coal plants, displacing coal-fired generation with increased utilization of natural gas combined cycle units, expanding renewable generation resources and increasing customer energy efficiency. Comments were due in December 2014. The Federal EPA also issued proposed regulations governing emissions of CO_2 from modified and reconstructed EGUs in June 2014 and comments were due in October 2014. The standards for modified and reconstructed units include several options, including use of historic baselines or energy efficiency audits to establish source-specific CO_2 emission rates or to limit CO_2 emission rates which could be no less than 1,900 pounds per MWh at larger coal units and 2,100 pounds per MWh at smaller coal units. The Federal EPA announced in January 2015 that the schedule for finalizing its action on all of these standards will extend into the summer of 2015 and that it will develop and propose for public comment a model FIP that will be finalized for individual states that fail to submit a timely state plan to implement the existing source standards. We cannot currently predict the impact these programs may have on future resource plans or our existing generating fleet, but the costs may be substantial.

In 2012, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision upholding, in all material respects, the Federal EPA's endangerment finding, its regulatory program for CO_2 emissions from new motor vehicles and its plan to phase in regulation of CO_2 emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. In June 2014, the U.S. Supreme Court determined that the Federal EPA was not compelled to regulate CO_2 emissions from stationary sources under the Title V or PSD programs as a result of its adoption of the motor vehicle standards, but that sources otherwise required to obtain a PSD permit may be required to perform a Best Available Control Technology analysis for CO_2 emissions if they exceed a reasonable level. The Federal EPA must undertake additional rulemaking to implement the court's decision and establish an appropriate level.

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

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

Coal Combustion Residual Rule

In 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and also FGD gypsum generated at some coal-fired plants. The proposed rule contained two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials and another would allow states to retain primary authority to regulate the beneficial re-use and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and existing unlined surface impoundments.

Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. To comply with a court-ordered deadline, the Federal EPA issued a prepublication copy of its final rule in December 2014. The rule is expected to be published in the Federal Register during the first quarter of 2015 and become effective six months following publication.

In the final rule, the Federal EPA elected to regulate CCR as a non-hazardous solid waste and issued new minimum federal solid waste management standards. On the effective date, the rule applies to new and existing active CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes new and additional construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria and additional groundwater monitoring requirements. The rule does not apply to inactive CCR landfills and inactive surface impoundments at retired generating stations or the beneficial use of CCR. The rule is self-implementing so state action is not required. Because of this self-implementing feature, the rule contains extensive record keeping, notice and internet posting requirements. Because we currently use surface impoundments and landfills to manage CCR materials at our generating facilities, we will incur significant costs to upgrade or close and replace these existing facilities at some point in the future as the new rule is implemented. We continue to review the new rule and evaluate its costs and impacts to our operations, including ongoing monitoring requirements.

In February 2014, the Federal EPA completed a risk evaluation of the beneficial uses of coal fly ash in concrete and FGD gypsum in wallboard and concluded that the Federal EPA supports these beneficial uses. Currently, approximately 40% of the coal ash and other residual products from our generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. Encapsulated beneficial uses are not materially impacted by the new rule but additional demonstrations may be required to continue land applications in significant amounts except in road construction projects.

Clean Water Act (CWA) Regulations

In 2014, the Federal EPA issued a final rule setting forth standards for existing power plants that is intended to reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. Entrainment is when small fish, eggs or larvae are drawn into the cooling water system and affected by heat, chemicals or physical stress. The final rule affects all plants withdrawing more than two million gallons of cooling water per day. The rule offers seven technology options to comply with the impingement standard and requires site-specific studies to determine appropriate entrainment compliance measures at facilities withdrawing more than 125 million gallons per day. Additional requirements may be imposed as a result of consultation with other federal agencies to protect threatened and endangered species and their habitats. Facilities with existing closed cycle recirculating cooling systems, as defined in the rule, are not expected to require any technology changes. Facilities subject to both the impingement standard and site-specific entrainment studies will typically be given at least three years to conduct and submit the results of those studies to the permit agency. Compliance timeframes will then be established by the permit agency through each facility's National Pollutant Discharge Elimination System (NPDES) permit for installation of any required technology changes, as those permits are renewed over the next five to eight years. Petitions for review of the final rule have been filed by industry and environmental groups and are currently pending in the U.S. Court of Appeals for the Second Circuit.

In addition, the Federal EPA issued an information collection request and is developing revised effluent limitation guidelines for electricity generating facilities. A proposed rule was signed in April 2013 with a final rule expected in September 2015. The Federal EPA proposed eight options of increasing stringency and cost for fly ash and bottom ash transport water, scrubber wastewater, leachate from coal combustion byproduct landfills and impoundments and other wastewaters associated with coal-fired generating units, with four labeled preferred options. Certain of the Federal EPA's preferred options have already been implemented or are part of our long-term plans. We continue to review the proposal in detail to evaluate whether our plants are currently meeting the proposed limitations, what technologies have been incorporated into our long-range plans and what additional costs might be incurred if the Federal EPA's most stringent options were adopted. We submitted detailed comments to the Federal EPA in September 2013 and participated in comments filed by various organizations of which we are members.

In April 2014, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a proposed rule to clarify the scope of the regulatory definition of "waters of the United States" in light of recent U.S. Supreme Court cases and published the proposed rule in the Federal Register. The CWA provides for federal jurisdiction over "navigable waters" defined as "the waters of the United States." This proposed jurisdictional definition will apply to all CWA programs, potentially impacting generation, transmission and distribution permitting and compliance requirements. Among those programs are: permits for wastewater and storm water discharges, permits for impacts to wetlands and water bodies and oil spill prevention planning. We agree that clarity and efficiency in the permitting process is needed. We are concerned that the proposed rule introduces new concepts and could subject more of our operations to CWA jurisdiction, thereby increasing the time and complexity of permitting. We submitted detailed comments to the Federal EPA in November 2014 and also participated in comments filed by various organizations of which we are members.

RESULTS OF OPERATIONS

SEGMENTS

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

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

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 to serve SSO customers, and provides capacity for all connected load.

AEP Transmission Holdco

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

Generation & Marketing

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

AEP River Operations

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

The table below presents Earnings Attributable to AEP Common Shareholders by segment for the years ended December 31, 2014, 2013 and 2012.

	Years Ended December 31,		
	2014	2013	2012
		(in millions)	
Vertically Integrated Utilities	$ 708	$ 677	$ 800
Transmission and Distribution Utilities	355	358	389
AEP Transmission Holdco	151	80	43
Generation & Marketing	367	228	100
AEP River Operations	49	12	15
Corporate and Other (a)	4	125	(88)
Earnings Attributable to AEP Common Shareholders	$ 1,634	$ 1,480	$ 1,259

(a) While not considered a reportable segment, Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.

AEP CONSOLIDATED

2014 Compared to 2013

Earnings Attributable to AEP Common Shareholders increased from $1,480 million in 2013 to $1,634 million in 2014 primarily due to:

- Impairments during 2013 for the following:
  - Muskingum River Plant, Unit 5.
  - A decision from the KPSC disallowing scrubber costs on KPCo's Big Sandy Plant.
- A net increase in weather-related usage.
- Higher market prices and increased sales volumes.
- An increase in transmission investment which resulted in higher revenues and income.
- Successful rate proceedings during 2014 in our various jurisdictions.

These increases were partially offset by:

- A favorable U.K. Windfall Tax decision by the U.S. Supreme Court in 2013.
- An increase in depreciation expense due to increased investments.
- An increase in regulatory provisions in 2014.
- An increase in fuel expense due to the termination of a long-term coal contract.
- An increase in plant maintenance.
- An increase in vegetation management expenses.

2013 Compared to 2012

Earnings Attributable to AEP Common Shareholders increased from $1,259 million in 2012 to $1,480 million in 2013 primarily due to:

- Successful rate proceedings in our various jurisdictions.
- 2012 impairments of certain Ohio generation plants.
- A decrease in Ohio depreciation expense due to impairments of certain Ohio generation plants.
- A favorable U.K. Windfall Tax decision by the U.S. Supreme Court in 2013.

These increases were partially offset by:

- Impairments during 2013 for the following:
  - Muskingum River Plant, Unit 5.
  - A write-off from a disallowance of a portion of Amos Plant, Unit 3 pursuant to a Virginia SCC order.
  - A decision from the KPSC disallowing scrubber costs on KPCo's Big Sandy Plant.
- The loss of retail generation customers in Ohio to various CRES providers.
- 2012 reversal of a 2011 recorded obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of OPCo's modified stipulation.

Our results of operations by operating segment are discussed below.

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Years Ended December 31, 2014	2013	2012
		(in millions)	
Revenues	$ 9,484	$ 9,992	$ 9,418
Fuel and Purchased Electricity	3,953	4,770	4,408
Gross Margin	5,531	5,222	5,010
Other Operation and Maintenance	2,515	2,276	2,219
Asset Impairments and Other Related Charges	—	72	13
Depreciation and Amortization	1,033	941	873
Taxes Other Than Income Taxes	370	372	344
Operating Income	1,613	1,561	1,561
Interest and Investment Income	4	7	5
Carrying Costs Income	6	14	28
Allowance for Equity Funds Used During Construction	47	35	72
Interest Expense	(526)	(540)	(520)
Income Before Income Tax Expense and Equity Earnings	1,144	1,077	1,146
Income Tax Expense	434	398	345
Equity Earnings of Unconsolidated Subsidiaries	2	2	2
Net Income	712	681	803
Net Income Attributable to Noncontrolling Interests	4	4	3
Earnings Attributable to AEP Common Shareholders	$ 708	$ 677	$ 800

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Years Ended December 31,		
	2014	2013	2012
	(in millions of KWhs)		
Retail:			
Residential	34,073	33,851	33,199
Commercial	25,048	25,037	25,278
Industrial	35,281	34,216	34,692
Miscellaneous	2,311	2,284	2,356
Total Retail	96,713	95,388	95,525
Wholesale (a)	34,241	NM (b)	NM (b)
Total KWhs	130,954	95,388	95,525

(a) Includes off-system sales, municipalities and cooperatives, unit power and other wholesale customers.
(b) 2014 is not comparable to 2013 or 2012 due to the 2013 asset transfers related to corporate separation in Ohio on December 31, 2013 and the termination of the Interconnection Agreement effective January 1, 2014.
NM Not meaningful.

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

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

	Years Ended December 31,		
	2014	2013	2012
	(in degree days)		
Eastern Region			
Actual – Heating (a)	3,313	2,949	2,216
Normal – Heating (b)	2,740	2,734	2,774
Actual – Cooling (c)	932	1,040	1,253
Normal – Cooling (b)	1,080	1,080	1,079
Western Region			
Actual – Heating (a)	1,840	1,772	1,070
Normal – Heating (b)	1,510	1,501	1,537
Actual – Cooling (c)	2,049	2,163	2,635
Normal – Cooling (b)	2,203	2,202	2,186

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

2014 Compared to 2013

Reconciliation of Year Ended December 31, 2013 to Year Ended December 31, 2014
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Year Ended December 31, 2013	$	677
Changes in Gross Margin:		
Retail Margins		212
Off-system Sales		123
Transmission Revenues		22
Other Revenues		(48)
Total Change in Gross Margin		309
Changes in Expenses and Other:		
Other Operation and Maintenance		(239)
Asset Impairments and Other Related Charges		72
Depreciation and Amortization		(92)
Taxes Other Than Income Taxes		2
Interest and Investment Income		(3)
Carrying Costs Income		(8)
Allowance for Equity Funds Used During Construction		12
Interest Expense		14
Total Change in Expenses and Other		(242)
Income Tax Expense		(36)
Year Ended December 31, 2014	$	708

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

- **Retail Margins** increased $212 million primarily due to the following:
  - The effect of successful rate proceedings in our service territories, which include:
    - A $129 million rate increase for APCo.
    - A $55 million rate increase for KPCo.
    - A $45 million rate increase for I&M.
    - A $22 million rate increase for SWEPCo.
    - A $12 million rate increase for PSO.
    - A $9 million rate increase for WPCo.

  For the rate increases described above, $153 million relates to riders/trackers which have corresponding increases in other expense items below.
  - A $14 million increase due to favorable weather conditions.

  These increases were partially offset by:
  - A $43 million increase in PJM expenses net of recovery or offsets.
  - A $36 million decrease due to a fuel proceeding disallowance.
- **Margins from Off-system Sales** increased $123 million primarily due to higher market prices and changes in margin sharing.
- **Transmission Revenues** increased $22 million primarily due to increased investment in the PJM region.
- **Other Revenues** decreased $48 million primarily due to a decrease in barging because River Transportation Division (RTD) is no longer serving plants transferred from OPCo to AGR as of December 31, 2013 as a result of corporate separation in Ohio. This decrease in RTD revenue has a corresponding decrease in Other Operation and Maintenance expenses for barging as discussed below.

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

- **Other Operation and Maintenance** expenses increased $239 million primarily due to the following:
  - A $56 million increase in recoverable expenses, primarily including PJM expenses, currently fully recovered in rate recovery riders/trackers, partially offset by RTD expenses for barging activities.
  - A $46 million increase in employee related expenses.
  - A $45 million increase in transmission services related to PJM and SPP services.
  - A $43 million increase in plant outage and maintenance expense primarily due to higher planned and advanced spending.
  - A $26 million increase in distribution and transmission vegetation management expenses primarily due to higher advanced spending.
  - A $25 million increase due to a favorable settlement of an insurance claim in the first quarter of 2013.
  - A $10 million increase due to the write-off of IGCC costs in Virginia.
  - An $8 million increase due to an accrual for future environmental remediation costs.

  These increases were partially offset by:
  - A $30 million write-off in the first quarter of 2013 of previously deferred 2012 Virginia storm costs resulting from the 2013 enactment of a Virginia law.
  - A $23 million decrease in storm expense primarily in the APCo service territory.
- **Asset Impairments and Other Related Charges** decreased $72 million primarily due to the following:
  - A $39 million decrease due to APCo's 2013 write-off from a regulatory disallowance of a portion of Amos Plant, Unit 3 pursuant to a Virginia SCC order approving the transfer of Amos Plant, Unit 3.
  - A $33 million decrease due to KPCo's 2013 write-off of scrubber costs on the Big Sandy Plant and other generation costs in accordance with the KPSC's October 2013 order.
- **Depreciation and Amortization** expenses increased $92 million primarily due to higher depreciable base.
- **Carrying Cost Income** decreased $8 million primarily due to the November 2013 securitization of the West Virginia ENEC deferral balance.
- **Allowance for Equity Funds Used During Construction** increased $12 million primarily due to increases in environmental construction and transmission projects.
- **Interest Expense** decreased $14 million primarily due to the following:
  - A $6 million decrease due to the retirement of KPCo Senior Unsecured Notes in the third quarter of 2013.
  - A $4 million decrease due to the redemption of I&M Senior Unsecured Notes in the fourth quarter of 2013.
  - A $4 million decrease due to rate approvals in Louisiana and Texas as well as an increase in the debt component of AFUDC due to increased transmission and environmental projects.
- **Income Tax Expense** increased $36 million primarily due to an increase in pretax book income, the recording of state income tax adjustments and other book/tax differences which are accounted for on a flow-through basis, partially offset by the recording of federal income tax adjustments.

2013 Compared to 2012

Reconciliation of Year Ended December 31, 2012 to Year Ended December 31, 2013
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Year Ended December 31, 2012	$	800
Changes in Gross Margin:		
Retail Margins		196
Off-system Sales		(26)
Transmission Revenues		41
Other Revenues		1
Total Change in Gross Margin		212
Changes in Expenses and Other:		
Other Operation and Maintenance		(57)
Asset Impairments and Other Related Charges		(59)
Depreciation and Amortization		(68)
Taxes Other Than Income Taxes		(28)
Interest and Investment Income		2
Carrying Costs Income		(14)
Allowance for Equity Funds Used During Construction		(37)
Interest Expense		(20)
Total Change in Expenses and Other		(281)
Income Tax Expense		(53)
Net Income Attributable to Noncontrolling Interests		(1)
Year Ended December 31, 2013	$	677

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

- **Retail Margins** increased $196 million primarily due to the following:
  - Successful rate proceedings in our service territories, which include:
    - A $153 million rate increase for SWEPCo.
    - A $112 million rate increase for I&M.
    - A $9 million rate increase for APCo.

      For the rate increases described above, $42 million relates to riders/trackers which have corresponding increases in other expense items below.
  - A $29 million increase in weather-related usage in our eastern and western regions primarily due to increases of 33% and 66%, respectively, in heating degree days, partially offset by decreases in our eastern and western regions of 17% and 18%, respectively, in cooling degree days.

  These increases were partially offset by:
  - A $15 million decrease in SWEPCo's municipal and cooperative revenues primarily due to lower realizations from changes in sales volume mix.
  - A $23 million decrease due to lower weather normalized retail sales.
  - A $12 million increase in other variable electric generation expenses.
  - A $9 million deferral of APCo's additional wind purchase costs in 2012 as a result of the June 2012 Virginia SCC fuel factor order.
  - A $9 million decrease due to adjustments for previously disallowed environmental costs by the November 2011 Virginia SCC order subsequently determined in 2012 to be appropriate for recovery by the Supreme Court of Virginia.

- **Margins from Off-system Sales** decreased $26 million primarily due to lower PJM capacity revenue, reduced trading and marketing margins, partially offset by higher prices and volumes.
- **Transmission Revenues** increased $41 million primarily due to increased investment in the PJM and SPP regions. These increased revenues are partially offset by Other Operation and Maintenance expenses below.

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

- **Other Operation and Maintenance** expenses increased $57 million primarily due to the following:
  - A $33 million increase in recoverable PJM and other expenses currently recovered dollar-for-dollar in rate recovery riders/trackers.
  - A $30 million write-off in 2013 of previously deferred 2012 Virginia storm costs resulting from the 2013 enactment of a Virginia law.
  - A $22 million increase in storm-related expenses primarily in APCo's service territory.
  - A $21 million increase in plant outage expenses.

  These increases were partially offset by:
  - A $26 million decrease due to expenses related to the 2012 sustainable cost reductions.
  - A $25 million decrease due to an agreement reached to settle an insurance claim in 2013.
- **Asset Impairments and Other Related Charges** increased $59 million primarily due to the following:
  - A $39 million increase due to APCo's 2013 write-off from a regulatory disallowance of a portion of Amos Plant, Unit 3 pursuant to a Virginia SCC order approving the transfer of Amos Plant, Unit 3.
  - A $33 million increase due to KPCo's 2013 write-off of scrubber costs on the Big Sandy Plant and other generation costs in accordance with the KPSC's October 2013 order.

  These increases were partially offset by:
  - A 2012 write-off of an additional $13 million related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap.
- **Depreciation and Amortization** expenses increased $68 million primarily due to the following:
  - A $40 million increase due to the Turk Plant being placed in service in December 2012.
  - A $26 million increase due to higher depreciable base and higher depreciation rates reflecting a change in Tanners Creek Plant's estimated life approved by the MPSC effective April 2012 and by the IURC effective March 2013. The majority of the increase in depreciation for Tanners Creek Plant's life is offset within Gross Margin.
  - Overall higher depreciable property balances.

  These increases were partially offset by:
  - A $13 million decrease in amortization as a result of the cessation of the Virginia Environmental and Reliability surcharge and the Virginia Environmental Rate Adjustment Clause in January 2013 and March 2013, respectively.
- **Taxes Other Than Income Taxes** increased $28 million primarily due to increased property taxes as a result of increased capital investments.
- **Carrying Costs Income** decreased $14 million primarily due to an increased recovery of Virginia environmental costs in new base rates as approved by the Virginia SCC in late January 2012 and decreased carrying charges related to the Dresden Plant.
- **Allowance for Equity Funds Used During Construction** decreased $37 million primarily due to completed construction of the Turk Plant in December 2012.
- **Interest Expense** increased $20 million primarily due to a decrease in the debt component of AFUDC due to completed construction of the Turk Plant in December 2012, partially offset by lower average outstanding long-term debt balances and an increase in the debt component of AFUDC related to projects at the Cook Plant.
- **Income Tax Expense** increased $53 million primarily due to the recording of federal and state income tax adjustments and other book/tax differences which are accounted for on a flow-through basis, partially offset by a decrease in pretax book income.

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Years Ended December 31, 2014	2013	2012
		(in millions)	
Revenues	$ 4,814	$ 4,478	$ 4,818
Purchased Electricity	1,520	1,627	2,071
Amortization of Generation Deferrals	111	—	—
Gross Margin	3,183	2,851	2,747
Other Operation and Maintenance	1,276	1,003	911
Depreciation and Amortization	658	591	561
Taxes Other Than Income Taxes	453	435	428
Operating Income	796	822	847
Interest and Investment Income	11	2	4
Carrying Costs Income	27	16	24
Allowance for Equity Funds Used During Construction	12	8	6
Interest Expense	(280)	(292)	(291)
Income Before Income Tax Expense	566	556	590
Income Tax Expense	211	198	201
Net Income	355	358	389
Net Income Attributable to Noncontrolling Interests	—	—	—
Earnings Attributable to AEP Common Shareholders	$ 355	$ 358	$ 389

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Years Ended December 31, 2014	2013	2012
		(in millions of KWhs)	
Retail:			
Residential	26,209	25,531	25,581
Commercial	25,307	24,631	24,746
Industrial	21,830	22,668	24,902
Miscellaneous	713	710	716
Total Retail (a)	74,059	73,540	75,945
Wholesale (b)	2,198	NM (c)	NM (c)
Total KWhs	76,257	73,540	75,945

(a) Represents energy delivered to distribution customers.

(b) Ohio's contractually obligated purchases of OVEC power sold into PJM.

(c) 2014 is not comparable to 2013 or 2012 due to the 2013 asset transfers related to corporate separation in Ohio on December 31, 2013 and the termination of the Interconnection Agreement effective January 1, 2014.

NM Not meaningful.

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

Summary of Heating and Cooling Degree Days for Transmission and Distribution Utilities

	Years Ended December 31,		
	2014	2013	2012
	(in degree days)		
Eastern Region			
Actual – Heating (a)	3,734	3,383	2,610
Normal – Heating (b)	3,230	3,229	3,276
Actual – Cooling (c)	949	1,029	1,248
Normal – Cooling (b)	960	954	948
Western Region			
Actual – Heating (a)	428	368	177
Normal – Heating (b)	337	337	352
Actual – Cooling (d)	2,553	2,737	3,100
Normal – Cooling (b)	2,618	2,608	2,584

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

2014 Compared to 2013

Reconciliation of Year Ended December 31, 2013 to Year Ended December 31, 2014
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Year Ended December 31, 2013	$	358
Changes in Gross Margin:		
Retail Margins		236
Off-System Sales		3
Transmission Revenues		71
Other Revenues		22
Total Change in Gross Margin		332
Changes in Expenses and Other:		
Other Operation and Maintenance		(273)
Depreciation and Amortization		(67)
Taxes Other Than Income Taxes		(18)
Interest and Investment Income		9
Carrying Costs Income		11
Allowance for Equity Funds Used During Construction		4
Interest Expense		12
Total Change in Expenses and Other		(322)
Income Tax Expense		(13)
Year Ended December 31, 2014	$	355

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of purchased electricity and amortization of generation deferrals were as follows:

- **Retail Margins** increased $236 million primarily due to the following:
  - A $106 million increase in revenues primarily associated with Ohio rate riders/trackers and PJM revenues, partially offset by regulatory provisions. These increases have corresponding increases in expense items discussed below.
  - A $96 million increase in TCC and TNC revenues primarily due to the recovery of ERCOT transmission expenses which is offset in Other Operation and Maintenance below.
- **Transmission Revenues** increased $71 million primarily due to:
  - A $58 million increase primarily due to increased transmission revenues from customers who have switched to alternative CRES providers, rate increases for customers in the PJM region and increased transmission investment. This increase in transmission revenues related to CRES providers primarily offsets lost revenues included in Retail Margins above.
  - A $14 million increase primarily due to increased transmission investment in ERCOT.
- **Other Revenues** increased $22 million primarily due to an increase in Texas securitization revenues which is offset in Depreciation and Amortization and Interest Expense below.

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

- **Other Operation and Maintenance** expenses increased $273 million primarily due to the following:
  - A $213 million increase in recoverable expenses, including PJM expenses, ERCOT expenses and the Ohio storm amortization, currently fully recovered in rate recovery riders/trackers.
  - A $19 million increase in expenses related to various distribution services as a result of advanced spending.
  - An $18 million increase in remitted Universal Service Fund (USF) surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase is offset by an increase in Retail Margins above.
  - A $9 million increase in vegetation management expenses primarily due to advanced spending.
- **Depreciation and Amortization** expenses increased $67 million primarily due to the following:
  - A $39 million increase in amortization related to OPCo and TCC securitizations, which are partially offset in Retail Margins and Other Revenues above.
  - A $28 million increase due to an increase in the depreciable base of transmission and distribution assets.
- **Taxes Other Than Income Taxes** increased $18 million primarily due to increased property taxes.
- **Interest and Investment Income** increased $9 million primarily due to interest on affiliated notes resulting from corporate separation.
- **Carrying Costs Income** increased $11 million primarily due to increased capacity deferral carrying charges.
- **Interest Expense** decreased $12 million primarily due to reduced TCC securitization long-term debt outstanding, which is partially offset in Other Revenues above.
- **Income Tax Expense** increased $13 million primarily due to an increase in pretax book income and by the recording of federal and state income tax adjustments.

2013 Compared to 2012

Reconciliation of Year Ended December 31, 2012 to Year Ended December 31, 2013
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Year Ended December 31, 2012	$	389
Changes in Gross Margin:		
Retail Margins		55
Off-System Sales		1
Transmission Revenues		46
Other Revenues		2
Total Change in Gross Margin		104
Changes in Expenses and Other:		
Other Operation and Maintenance		(92)
Depreciation and Amortization		(30)
Taxes Other Than Income Taxes		(7)
Interest and Investment Income		(2)
Carrying Costs Income		(8)
Allowance for Equity Funds Used During Construction		2
Interest Expense		(1)
Total Change in Expenses and Other		(138)
Income Tax Expense		3
Year Ended December 31, 2013	$	358

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of purchased electricity were as follows:

- **Retail Margins** increased $55 million primarily due to the following:
  - A $123 million increase in revenues associated with OPCo's USF surcharge and Distribution Investment Recovery Rider. A portion of these increases have corresponding increases in other expense items below.
  - A $17 million increase related to favorable regulatory proceedings for OPCo.

  These increases were partially offset by:
  - A $40 million decrease related to Ohio customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.
  - A $35 million decrease due to OPCo's partial reversal in 2012 of a 2011 fuel provision related to CRES providers.
- **Transmission Revenues** increased $46 million primarily due to increased transmission revenues from Ohio customers who switched to alternative CRES providers.

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

- **Other Operation and Maintenance** expenses increased $92 million primarily due to the following:
  - An $86 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in Retail Margins above.
  - A $30 million net increase related to the reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of the Ohio modified stipulation and the PUCO's August 2012 approval of the June 2012-May 2015 ESP.

  These increases were partially offset by:
  - A $14 million decrease in expenses related to the 2012 sustainable cost reductions.
  - A $13 million decrease in Ohio's *gridSMART*® expenses primarily due to a reduction in the operation and maintenance component of the *gridSMART*® rider for prior years' over collections. This decrease was partially offset by a corresponding increase in Depreciation and Amortization.
- **Depreciation and Amortization** expenses increased $30 million primarily due to the following:
  - An $8 million increase due to OPCo's and TCC's issuance of securitization bonds in August 2013 and March 2012, respectively. This increase in OPCo's and TCC's securitization related amortizations are offset within Gross Margin.
  - A $7 million increase due to increased investment in distribution and transmission plant.
  - A $4 million increase in Ohio's *gridSMART*® expenses primarily due to an increase in the depreciation component of the *gridSMART*® rider to recover prior years' under collections. This increase was offset by a corresponding decrease in Operation and Maintenance expenses above.
- **Taxes Other Than Income Taxes** increased $7 million primarily due to increased property taxes.
- **Carrying Costs Income** decreased $8 million primarily due to the first quarter 2012 recording of debt carrying costs prior to TCC's issuance of securitization bonds in March 2012.
- **Income Tax Expense** decreased $3 million primarily due to a decrease in pretax book income, partially offset by the recording of state income tax adjustments.

AEP TRANSMISSION HOLDCO

AEP Transmission Holdco	Years Ended December 31, 2014	2013	2012
		(in millions)	
Transmission Revenues	$ 192	$ 78	$ 24
Gross Margin	192	78	24
Other Operation and Maintenance	29	12	9
Depreciation and Amortization	24	10	3
Taxes Other Than Income Taxes	32	20	5
Operating Income	107	36	7
Carrying Costs Income	—	—	1
Allowance for Equity Funds Used During Construction	45	30	14
Interest Expense	(23)	(10)	(3)
Income Before Income Tax Expense	129	56	19
Income Tax Expense	63	29	17
Equity Earnings of Unconsolidated Subsidiaries	85	53	41
Net Income	151	80	43
Net Income Attributable to Noncontrolling Interests	—	—	—
Earnings Attributable to AEP Common Shareholders	$ 151	$ 80	$ 43

Summary of Net Plant In Service and CWIP for Transmission Holdco

	As of December 31, 2014	2013	2012
		(in millions)	
Net Plant In Service	$ 1,801	$ 982	$ 374
CWIP	889	645	370

2014 Compared to 2013

Reconciliation of Year Ended December 31, 2013 to Year Ended December 31, 2014 Earnings Attributable to AEP Common Shareholders from Transmission Holdco (in millions)

Year Ended December 31, 2013	$	80
Changes in Transmission Revenues:		
Transmission Revenues		114
Total Change in Transmission Revenues		114
Changes in Expenses and Other:		
Other Operation and Maintenance		(17)
Depreciation and Amortization		(14)
Taxes Other Than Income Taxes		(12)
Allowance for Equity Funds Used During Construction		15
Interest Expense		(13)
Total Change in Expenses and Other		(41)
Income Tax Expense		(34)
Equity Earnings		32
Year Ended December 31, 2014	$	151

The major components of the increase in transmission revenues, which consists of wholesale sales to affiliates and non-affiliates were as follows:

- **Transmission Revenues** increased $114 million primarily due to an increase in projects placed in-service by our wholly-owned transmission subsidiaries.

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

- **Other Operation and Maintenance** expenses increased $17 million primarily due to increased transmission investment.
- **Depreciation and Amortization** expenses increased $14 million primarily due to higher depreciable base.
- **Taxes Other Than Income Taxes** increased $12 million primarily due to increased property taxes.
- **Allowance for Equity Funds Used During Construction** increased $15 million primarily due to increased transmission investment.
- **Interest Expense** increased $13 million primarily due to higher outstanding long-term debt balances.
- **Income Tax Expense** increased $34 million primarily due to an increase in pretax book income.
- **Equity Earnings** increased $32 million primarily due to an increase in transmission investment by ETT.

2013 Compared to 2012

Reconciliation of Year Ended December 31, 2012 to Year Ended December 31, 2013
Earnings Attributable to AEP Common Shareholders from Transmission Holdco
(in millions)

Year Ended December 31, 2012	$	43
Changes in Transmission Revenues:		
Transmission Revenues		54
Total Change in Transmission Revenues		54
Changes in Expenses and Other:		
Other Operation and Maintenance		(3)
Depreciation and Amortization		(7)
Taxes Other Than Income Taxes		(15)
Carrying Costs Income		(1)
Allowance for Equity Funds Used During Construction		16
Interest Expense		(7)
Total Change in Expenses and Other		(17)
Income Tax Expense		(12)
Equity Earnings		12
Year Ended December 31, 2013	$	80

The major components of the increase in transmission revenues, which consists of wholesale sales to affiliates and non-affiliates were as follows:

- **Transmission Revenues** increased $54 million primarily due to an increase in projects placed in-service by our wholly-owned transmission subsidiaries.

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

- **Other Operation and Maintenance** expenses increased $3 million primarily due increased transmission investment.
- **Depreciation and Amortization** expenses increased $7 million primarily due to higher depreciable base.
- **Taxes Other Than Income Taxes** increased $15 million primarily due to increased property taxes.
- **Allowance for Equity Funds Used During Construction** increased $16 million primarily due to increased transmission investment.
- **Interest Expense** increased $7 million primarily due to higher outstanding long-term debt balances.
- **Income Tax Expense** increased $12 million primarily due to an increase in pretax book income, partially offset by other book/tax differences which are accounted for on a flow-through basis.
- **Equity Earnings** increased $12 million primarily due to an increase in transmission investment by ETT.

GENERATION & MARKETING

Generation & Marketing	Years Ended December 31, 2014	2013	2012
		(in millions)	
Revenues	$ 3,850	$ 3,665	$ 3,467
Fuel, Purchased Electricity and Other	2,436	2,305	2,065
Gross Margin	1,414	1,360	1,402
Other Operation and Maintenance	550	523	507
Asset Impairments and Other Related Charges	—	154	287
Depreciation and Amortization	227	236	349
Taxes Other Than Income Taxes	50	54	62
Operating Income	587	393	197
Interest and Investment Income	5	2	1
Interest Expense	(46)	(55)	(83)
Income Before Income Tax Expense	546	340	115
Income Tax Expense	179	112	15
Net Income	367	228	100
Net Income Attributable to Noncontrolling Interests	—	—	—
Earnings Attributable to AEP Common Shareholders	$ 367	$ 228	$ 100

Summary of MWhs Generated for Generation & Marketing

	Years Ended December 31, 2014	2013	2012
		(in millions of MWhs)	
Fuel Type:			
Coal	38	38	37
Natural Gas	7	6	11
Wind	1	1	1
Total MWhs	46	45	49

2014 Compared to 2013

Reconciliation of Year Ended December 31, 2013 to Year Ended December 31, 2014 Earnings Attributable to AEP Common Shareholders from Generation & Marketing (in millions)

Year Ended December 31, 2013	$	228
Changes in Gross Margin:		
Generation		57
Retail, Trading and Marketing		(4)
Other		1
Total Change in Gross Margin		54
Changes in Expenses and Other:		
Other Operation and Maintenance		(27)
Asset Impairments and Other Related Charges		154
Depreciation and Amortization		9
Taxes Other Than Income Taxes		4
Interest and Investment Income		3
Interest Expense		9
Total Change in Expenses and Other		152
Income Tax Expense		(67)
Year Ended December 31, 2014	$	367

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

- **Generation** increased $57 million primarily due to $111 million of increased demand and market prices driven by cold temperatures in the first quarter of 2014, partially offset by $54 million due to the termination of a long-term coal contract.

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

- **Other Operation and Maintenance** expenses increased $27 million primarily due to increased ARO costs related to planned retirements.
- **Asset Impairments and Other Related Charges** decreased by $154 million primarily due to the 2013 impairment of Muskingum River Plant, Unit 5.
- **Depreciation and Amortization** expenses decreased $9 million primarily due to the 2013 impairment of Muskingum River Plant, Unit 5.
- **Interest Expense** decreased $9 million primarily due to lower outstanding long-term debt balances and lower long-term interest rates.
- **Income Tax Expense** increased $67 million primarily due to an increase in pretax book income.

2013 Compared to 2012

Reconciliation of Year Ended December 31, 2012 to Year Ended December 31, 2013
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Year Ended December 31, 2012	$	100
Changes in Gross Margin:		
Generation		(44)
Retail, Trading and Marketing		4
Other		(2)
Total Change in Gross Margin		(42)
Changes in Expenses and Other:		
Other Operation and Maintenance		(16)
Asset Impairments and Other Related Charges		133
Depreciation and Amortization		113
Taxes Other Than Income Taxes		8
Interest and Investment Income		1
Interest Expense		28
Total Change in Expenses and Other		267
Income Tax Expense		(97)
Year Ended December 31, 2013	$	228

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

- **Generation** decreased $44 million primarily due to the following:
  - A $336 million decrease in affiliated sales to OPCo primarily due to customers switching to alternative CRES providers as well as a reduction in industrial usage.

  This decrease was partially offset by the following:
  - A $221 million net increase in sales to AEP affiliates under the Interconnection Agreement.
  - A $63 million decrease in fuel expenses due to a reduction in generation at the Lawrenceburg Plant.

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

- **Other Operation and Maintenance** expenses increased $16 million primarily due to a 2013 adjustment of $14 million to impaired plant investment as a result of changes to asset retirement obligations for asbestos removal and retirement of ash disposal facilities at impaired plants.
- **Asset Impairments and Other Related Charges** decreased $133 million due to the following:
  - A 2012 impairment of $287 million for certain Ohio generation plants, which includes $13 million of related materials and supplies inventory.

  This decrease was partially offset by:
  - A 2013 impairment of $154 million for Muskingum River Plant, Unit 5.
- **Depreciation and Amortization** expenses decreased $113 million primarily due to depreciation ceasing on certain Ohio generation plants that were impaired in November 2012 and June 2013.
- **Interest Expense** decreased $28 million primarily due to lower outstanding long-term debt balances and lower long-term interest rates.
- **Income Tax Expense** increased $97 million primarily due to an increase in pretax book income and by the recording of state income tax adjustments.

AEP RIVER OPERATIONS

2014 Compared to 2013

Earnings attributable to AEP Common Shareholders from our AEP River Operations segment increased from $12 million in 2013 to $49 million in 2014 due to a 28% increase in barge freight revenue for 2014 compared to 2013. The increase in 2014 freight revenue over 2013 was driven by strong barge freight demand particularly for export grain, strong northbound imports of fertilizer, salt and steel and increased shipments of domestic coal.

2013 Compared to 2012

Earnings attributable to AEP Common Shareholders from our AEP River Operations segment decreased from $15 million in 2012 to $12 million in 2013 primarily due to significant reductions in export grain and coal demand. In addition, low water levels in the first and fourth quarters of 2013 limited barge loads and tow sizes.

CORPORATE AND OTHER

2014 Compared to 2013

Earnings attributable to AEP Common Shareholders from Corporate and Other decreased from $125 million in 2013 to $4 million in 2014 primarily due to a favorable U.K. Windfall Tax decision by the U.S. Supreme Court in 2013.

2013 Compared to 2012

Earnings attributable to AEP Common Shareholders from Corporate and Other increased from a loss of $88 million in 2012 to income of $125 million in 2013 primarily due to a favorable U.K. Windfall Tax decision by the U.S. Supreme Court in 2013 as well as a reduction in interest expense associated with the early retirement of debt in 2012.

AEP SYSTEM INCOME TAXES

2014 Compared to 2013

Income Tax Expense increased $258 million primarily due to an increase in pretax book income and the recording of state income tax adjustments and by a favorable U.K. Windfall Tax decision by the U.S. Supreme Court in 2013.

2013 Compared to 2012

Income Tax Expense increased $80 million primarily due to an increase in pretax book income and the recording of state income tax adjustments, partially offset by a favorable U.K. Windfall Tax decision by the U.S. Supreme Court in 2013.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	December 31,			
	2014		2013	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 18,684	50.7%	$ 18,377	52.2%
Short-term Debt	1,346	3.6	757	2.1
Total Debt	20,030	54.3	19,134	54.3
AEP Common Equity	16,820	45.7	16,085	45.7
Noncontrolling Interests	4	—	1	—
Total Debt and Equity Capitalization	$ 36,854	100.0%	$ 35,220	100.0%

Our ratio of debt-to-total capital remained unchanged at 54.3% as of December 31, 2014 and 2013.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. We believe we have adequate liquidity under our existing credit facilities. As of December 31, 2014, we had $3.5 billion in aggregate credit facility commitments to support our operations. Additional liquidity is available from cash from operations and a receivables securitization agreement. We are committed to maintaining adequate liquidity. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-leaseback or leasing agreements or common stock.

Commercial Paper Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. As of December 31, 2014, our available liquidity was approximately $3 billion as illustrated in the table below:

	Amount	Maturity
	(in millions)	
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,750	June 2017
Revolving Credit Facility	1,750	July 2018
Total	3,500	
Cash and Cash Equivalents	163	
Total Liquidity Sources	3,663	
Less: AEP Commercial Paper Outstanding	602	
Letters of Credit Issued	63	
Net Available Liquidity	$ 2,998	

We have credit facilities totaling $3.5 billion to support our commercial paper program. The credit facilities allow us to issue letters of credit in an amount up to $1.2 billion.

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The maximum amount of commercial paper outstanding during 2014 was $877 million. The weighted-average interest rate for our commercial paper during 2014 was 0.29%.

Other Credit Facilities

In January 2014, we issued letters of credit utilizing the entire amount available under an $85 million uncommitted facility. In October 2014, we renewed the uncommitted facility through October 2015 and increased the size of the facility to $100 million. As of December 31, 2014, the maximum future payments issued under the uncommitted facility was $81 million with a maturity date of July 2015. An uncommitted facility gives the issuer of the facility the right to accept or decline each request we make under the facility.

Financing Plan

As of December 31, 2014, we have $2.5 billion of long-term debt due within one year which includes $785 million of Pollution Control Bonds with mandatory tender dates and credit support for variable interest rates that requires the debt be classified as current. Also included in our long-term debt due within one year is $427 million of securitization bonds and DCC Fuel notes which will be repaid. We plan to refinance the majority of our other maturities due within one year.

Securitized Accounts Receivables

Our receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement expires in June 2016.

Debt Covenants and Borrowing Limitations

Our credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually defined in our credit agreements. Debt as defined in the credit agreements excludes securitization bonds and debt of AEP Credit. As of December 31, 2014, this contractually-defined percentage was 51%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of December 31, 2014, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements. This condition also applies in a majority of our non-exchange traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under our non-exchange traded commodity contracts would not cause an event of default under our credit agreements.

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

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders and we manage our borrowings to stay within those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.53 per share in January 2015. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Our income derives from our common stock equity in the earnings of our utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends. However, we do not believe these restrictions will have any significant impact on Parent's ability to access cash to meet the payment of dividends on its common stock.

Credit Ratings

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

CASH FLOW

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

	Years Ended December 31,		
	2014	**2013**	**2012**
		(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 118	$ 279	$ 221
Net Cash Flows from Operating Activities	4,613	4,106	3,804
Net Cash Flows Used for Investing Activities	(4,406)	(3,818)	(3,391)
Net Cash Flows Used for Financing Activities	(162)	(449)	(355)
Net Increase (Decrease) in Cash and Cash Equivalents	45	(161)	58
Cash and Cash Equivalents at End of Period	$ 163	$ 118	$ 279

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

Operating Activities

	Years Ended December 31,		
	2014	**2013**	**2012**
		(in millions)	
Net Income	$ 1,638	$ 1,484	$ 1,262
Depreciation and Amortization	1,929	1,743	1,782
Other	1,046	879	760
Net Cash Flows from Operating Activities	$ 4,613	$ 4,106	$ 3,804

Net Cash Flows from Operating Activities were $4.6 billion in 2014 consisting primarily of Net Income of $1.6 billion, and $1.9 billion of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Deferred Income Taxes increased primarily due to provisions in the Tax Increase Prevention Act of 2014 and an increase in tax versus book temporary differences from operations. The reduction in Fuel, Material and Supplies balance reflect a decrease in fuel inventory due to cold winter weather and increased generation.

Net Cash Flows from Operating Activities were $4.1 billion in 2013 consisting primarily of Net Income of $1.5 billion, $1.7 billion of noncash Depreciation and Amortization and $226 million of Asset Impairments related to Muskingum River Plant, Unit 5, Big Sandy and Amos Plants, partially offset by $214 million of Ohio capacity deferrals as a result of a 2012 PUCO order. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Deferred Income Taxes increased primarily due to provisions in the Taxpayer Relief Act of 2012 and an increase in tax versus book temporary differences from operations. Significant changes in other items include the favorable impact of a decrease in fuel inventory and net cash flows for Accrued Taxes as a result of the recognition of the tax benefit related to the U.K. Windfall Tax.

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

Investing Activities

	Years Ended December 31,		
	2014	2013	2012
		(in millions)	
Construction Expenditures	$ (4,134)	$ (3,624)	$ (3,025)
Acquisitions of Nuclear Fuel	(116)	(154)	(107)
Acquisitions of Assets/Businesses	(65)	(32)	(94)
Proceeds from Sales of Assets	6	21	18
Other	(97)	(29)	(183)
Net Cash Flows Used for Investing Activities	$ (4,406)	$ (3,818)	$ (3,391)

Net Cash Flows Used for Investing Activities were $4.4 billion in 2014 primarily due to Construction Expenditures for environmental, distribution and transmission investments. We also purchased transmission assets for $38 million.

Net Cash Flows Used for Investing Activities were $3.8 billion in 2013 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

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

Financing Activities

	Years Ended December 31,		
	2014	2013	2012
		(in millions)	
Issuance of Common Stock, Net	$ 73	$ 84	$ 83
Issuance/Retirement of Debt, Net	876	385	544
Proceeds from Nuclear Fuel Sale/Leaseback	—	110	—
Dividends Paid on Common Stock	(998)	(954)	(916)
Other	(113)	(74)	(66)
Net Cash Flows Used for Financing Activities	$ (162)	$ (449)	$ (355)

Net Cash Flows Used for Financing Activities in 2014 were $162 million. Our net debt issuances were $876 million. The net issuances included issuances of $1.6 billion of senior unsecured notes and other debt notes, $444 million of pollution control bonds and an increase in short-term borrowing of $589 million offset by retirements of $1.1 billion of notes, $412 million of pollution control bonds and $306 million of securitization bonds. We paid common stock dividends of $998 million. See Note 14 – Financing Activities.

Net Cash Flows Used for Financing Activities in 2013 were $449 million. Our net debt issuances were $385 million. The net issuances included issuances of $745 million of senior unsecured notes, $1 billion draws on a $1 billion term credit facility, $647 million of securitization bonds, $328 million of notes payable and other debt and $305 million of pollution control bonds offset by retirements of $1.8 billion of senior unsecured and other debt notes, $331 million of pollution control bonds, $243 million of securitization bonds and a decrease in short-term borrowing of $224 million. We paid common stock dividends of $954 million.

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

The following financing activities occurred during 2014:

AEP Common Stock:

- During 2014, we issued 1.6 million shares of common stock under our incentive compensation, employee saving and dividend reinvestment plans and received net proceeds of $73 million.

Debt:

- During 2014, we issued approximately $2.1 billion of long-term debt, including $1.3 billion of senior notes at interest rates ranging from 2.61% to 5.52% and $200 million of pollution control revenue bonds at interest rates ranging from 1.625% to 1.75%, $244 million of pollution control revenue bonds at variable interest rates and $359 million of other debt at variable interest rates. The proceeds from these issuances were used to fund long-term debt maturities and our construction programs.
- During 2014, we entered no interest rate derivatives and settled $4.7 million of such transactions. The settlements resulted in net cash received of $3 million. As of December 31, 2014, we had in place $815 million of notional interest rate derivatives designated as cash flow and fair value hedges.

In 2015:

- In January 2015, TCC retired $120 million of Securitization Bonds.
- In January 2015, OPCo retired $22 million of Securitization Bonds.
- In January 2015, SWEPCo remarketed $54 million of 1.6% Pollution Control Bonds due in 2019.
- In January 2015, PSO issued $87.5 million of 3.17% and $87.5 million of 4.09% Senior Unsecured Notes due in 2025 and 2045, respectively.
- In January and February 2015, I&M retired $23 million of Notes Payable related to DCC Fuel.
- In February 2015, APCo retired $11 million of Securitization Bonds.

BUDGETED CONSTRUCTION EXPENDITURES

We forecast approximately $4.5 billion of construction expenditures including debt AFUDC for 2015. For 2016 and 2017, we forecast construction expenditures of $3.8 billion and $3.9 billion, respectively. The expenditures are generally for transmission, generation, distribution and required environmental investment to comply with Federal EPA rules. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. We expect to fund these construction expenditures through cash flows from operations and financing activities. Generally, the subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. The 2015 estimated construction expenditures include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	2015 Budgeted Construction Expenditures					
Segment	Environmental	Generation	Transmission	Distribution	Other	Total
			(in millions)			
Vertically Integrated Utilities	$ 594	$ 496	$ 472	$ 654	$ 110	$ 2,326
Transmission and Distribution Utilities	2	2	359	545	64	972
AEP Transmission Holdco	—	—	988	—	7	995
Generation & Marketing	65	70	—	—	10	145
AEP River Operations	—	9	—	—	—	9
Corporate and Other	—	—	—	—	12	12
Total	$ 661	$ 577	$ 1,819	$ 1,199	$ 203	$ 4,459

OFF-BALANCE SHEET ARRANGEMENTS

Our current guidelines restrict the use of off-balance sheet financing entities or structures to traditional operating lease arrangements that we enter in the normal course of business. The following identifies significant off-balance sheet arrangements.

Rockport Plant, Unit 2

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant, Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for AEGCo and I&M are $592 million each as of December 31, 2014.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. Our subsidiaries account for the lease as an operating lease with the future payment obligations included in Note 13. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. We, as well as our subsidiaries, have no ownership interest in the Owner Trustee and do not guarantee its debt.

Railcars

In June 2003, we entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. We intend to maintain the lease for the full lease term of twenty years via the renewal options. The lease is accounted for as an operating lease. The future minimum lease obligation is $24 million for the remaining railcars as of December 31, 2014. Under a return-and-sale option, the lessor is guaranteed that the sale proceeds will equal at least a specified lessee obligation amount which declines with each five-year renewal. As of

December 31, 2014, the maximum potential loss was approximately $19 million assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair value would produce a sufficient sales price to avoid any loss. We have other railcar lease arrangements that do not utilize this type of financing structure.

CONTRACTUAL OBLIGATION INFORMATION

Our contractual cash obligations include amounts reported on the balance sheets and other obligations disclosed in our footnotes. The following table summarizes our contractual cash obligations as of December 31, 2014:

Payments Due by Period

Contractual Cash Obligations	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Short-term Debt (a)	$ 1,346	$ —	$ —	$ —	$ 1,346
Interest on Fixed Rate Portion of Long-term Debt (b)	819	1,530	1,285	7,079	10,713
Fixed Rate Portion of Long-term Debt (c)	1,180	2,629	3,057	9,938	16,804
Variable Rate Portion of Long-term Debt (d)	1,323	548	33	—	1,904
Capital Lease Obligations (e)	134	218	109	239	700
Noncancelable Operating Leases (e)	293	520	462	693	1,968
Fuel Purchase Contracts (f)	2,154	2,815	1,931	2,501	9,401
Energy and Capacity Purchase Contracts	363	405	426	2,087	3,281
Construction Contracts for Capital Assets (g)	1,332	1,604	814	1,571	5,321
Total	$ 8,944	$ 10,269	$ 8,117	$ 24,108	$ 51,438

(a) Represents principal only excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2014 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See "Long-term Debt" section of Note 14. Represents principal only, excluding interest.
(d) See "Long-term Debt" section of Note 14. Represents principal only, excluding interest. Variable rate debt had interest rates that ranged between 0.04% and 1.89% as of December 31, 2014.
(e) See Note 13.
(f) Represents contractual obligations to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents only capital assets for which we have signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

Our $124 million liability related to uncertainty in Income Taxes is not included above because we cannot reasonably estimate the cash flows by period.

Our pension funding requirements are not included in the above table. As of December 31, 2014, we expect to make contributions to our pension plans totaling $93 million in 2015. Estimated contributions of $93 million in 2016 and $97 million in 2017 may vary significantly based on market returns, changes in actuarial assumptions and other factors. Based upon the projected benefit obligation and fair value of assets available to pay pension benefits, our pension plans were 95.1% funded as of December 31, 2014.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds and other commitments. As of December 31, 2014, our commitments outstanding under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period

Other Commercial Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Standby Letters of Credit (a)	$ 63	$ —	$ —	$ —	$ 63
Guarantees of the Performance of Outside Parties (b)	—	—	—	115	115
Guarantees of Our Performance (c)	991	12	—	59	1,062
Total Commercial Commitments	$ 1,054	$ 12	$ —	$ 174	$ 1,240

(a) We enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as natural gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves. AEP, on behalf of our subsidiaries, and/or the subsidiaries issued all of these LOCs in the ordinary course of business. There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any LOC is drawn, there is no recourse to third parties. The maximum future payments of these LOCs are $63 million with maturities ranging from February 2015 to March 2016. See "Letters of Credit" section of Note 6.

(b) See "Guarantees of Third-Party Obligations" section of Note 6.

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

SIGNIFICANT TAX LEGISLATION

The Small Business Jobs Act extended the time for claiming bonus depreciation and increased the deduction to 100% for 2011 and decreased the deduction to 50% for 2012. The American Taxpayer Relief Act of 2012 provided for the extension of several business and energy industry tax deductions and credits, including the one-year extension of the 50% bonus depreciation to 2013. The Tax Increase Prevention Act of 2014 also included a one-year extension of the 50% bonus depreciation and provided for the extension of research and development, employment and several energy tax credits for 2014. These enacted provisions had no material impact on net income or financial condition but did have a favorable impact on cash flows in 2013 and 2014 and are expected to have a favorable impact on cash flows in 2015.

CYBER SECURITY

Cyber security presents a growing risk for electric utility systems because a cyber-attack could affect critical energy infrastructure. Breaches to the cyber security of the grid or to our system are potentially disruptive to people, property and commerce and create risk for our business, investors and customers. In February 2013, President Obama signed an executive order that addresses how government agencies will operate and support the functions in cyber security as well as redefines how the government interfaces with critical infrastructure, such as the electric grid. We already operate under regulatory cyber security standards to protect critical infrastructure. The cyber security framework that is being developed through this executive order will be reviewed by FERC and the U.S. Department of Energy (DOE). In 2014, the DOE developed an Energy Sector Cyber Security Framework Implementation Guide for utilities to use in adopting and implementing the National Institute of Standards and Technology framework. We are actively engaged in the framework adoption process.

The electric utility industry is one of the few critical infrastructure functions with mandatory cyber security requirements under the authority of FERC. The Energy Policy Act of 2005 gave FERC the authority to oversee reliability of the bulk power system, including the authority to approve mandatory cyber security reliability standards. North American Electric Reliability Corporation (NERC), which FERC certified as the nation's Electric Reliability Organization,

developed critical infrastructure protection cyber security reliability standards. In 2013, as part of our industry's continuing program to advance threat sharing and coordination, we participated in the NERC GridEx II exercise. This effort, led by NERC, tested and developed the coordination and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation's electric grid.

We protect our critical cyber assets, such as our data centers, power plants, transmission operations centers and business network, using multiple layers of cyber security and authentication. We constantly scan the system for risks or threats. Cyber hackers have been able to breach a number of very secure facilities, from federal agencies, banks and retailers to social media sites. As these events become known and develop, we continually assess our own cyber security tools and processes to determine where we might need to strengthen our defenses. We continually review our business continuity plan to develop an effective recovery effort that decreases our response times, limits financial impacts and maintains customer confidence following any business interruption. Management works closely with a broad range of departments, including Legal, Regulatory, Corporate Communications and Information Technology Security, to ensure the corporate response to consequences of any breach or potential breach is appropriate both for internal and external audiences based on the specific circumstances surrounding the event.

We continue to take steps to enhance our capabilities for identifying risks or threats and have shared that knowledge with our utility peers, industry and federal agencies. We operate our own Cyber Security Operations Center. Funding for this included a grant from the American Recovery and Reinvestment Act – U.S. Department of Energy Smart Grid Demonstration Program. This facility was initially designed as a pilot cyber threat and information-sharing center specifically for the electric sector and is fully operational.

We have partnered with a major defense contractor who has significant cyber security experience and technical capabilities developed through their work with the U.S. Department of Defense. We work with a consortium of other utilities across the country, learning how best to share information about potential threats and collaborating with each other. We continue to work with a nonaffiliated entity to conduct several seminars each year about recognizing and investigating cyber vulnerabilities. Through these types of efforts, we are working to protect ourselves while helping our industry advance its cyber security capabilities.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

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

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

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

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

Regulatory Accounting

Nature of Estimates Required

Our financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

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

Assumptions and Approach Used

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

Effect if Different Assumptions Used

A change in the above assumptions may result in a material impact on our net income. Refer to Note 5 for further detail related to regulatory assets and regulatory liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

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

The changes in unbilled electric utility revenues for our Vertically Integrated Utilities segment were $(29) million, $(9) million and $13 million for the years ended December 31, 2014, 2013 and 2012, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rate increases. Accrued unbilled revenues for the Vertically Integrated Utilities segment were $254 million and $283 million as of December 31, 2014 and 2013, respectively.

The changes in unbilled electric utility revenues for our Transmission and Distribution Utilities segment were $16 million, $(22) million and $(12) million for the years ended December 31, 2014, 2013 and 2012, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rate increases. Accrued unbilled revenues for the Transmission and Distribution Utilities segment were $181 million and $165 million as of December 31, 2014 and 2013, respectively.

In March 2012, our Generation & Marketing segment acquired an independent retail electric supplier. The change in unbilled electric utility revenues for our Generation & Marketing segment was $9 million, $10 million and $34 million for the years ended December 31, 2014, 2013 and 2012, respectively. Accrued unbilled revenues for the Generation & Marketing segment were $50 million and $41 million as of December 31, 2014 and 2013, respectively.

Assumptions and Approach Used

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

For certain contracts, we calculate unbilled revenues by contract using the most recent historic daily activity adjusted for significant known changes in usage.

Effect if Different Assumptions Used

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

Accounting for Derivative Instruments

Nature of Estimates Required

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

Assumptions and Approach Used

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

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

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

Effect if Different Assumptions Used

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

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

For additional information regarding derivatives, hedging and fair value measurements, see Notes 10 and 11. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

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

Assumptions and Approach Used

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

Effect if Different Assumptions Used

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

Pension and Other Postretirement Benefits

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

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1. See Note 8 for information regarding costs and assumptions for employee retirement and postretirement benefits.

The following table shows the net periodic cost (credit) of the Plans:

Net Periodic Benefit Cost (Credit)	Years Ended December 31, 2014	2013	2012
		(in millions)	
Pension Plans	$ 158	$ 180	$ 134
Postretirement Plans	(77)	(17)	89

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2015, we evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. We also considered historical returns of the investment markets and changes in tax rates which affect a portion of the Postretirement Plans' assets. We anticipate that the investment managers we employ for the Plans will invest the assets to generate future returns averaging 6% for the Qualified Plan and 6.75% for the Postretirement Plans.

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

	Pension Plans		Other Postretirement Benefit Plans	
	2015 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return	2015 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return
Equity	30%	8.50%	65%	8.50%
Fixed Income	55%	4.10%	33%	4.10%
Other Investments	15%	7.30%	—%	—%
Cash and Cash Equivalents	—%	—%	2%	2.80%
Total	100%		100%	

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. We believe that 6% and 6.75% are reasonable estimates of the long-term rate of return on the Plans' assets. The Pension Plans' assets had an actual gain of 10.6% and 8.1% for the years ended December 31, 2014 and 2013, respectively. The Postretirement Plans' assets had an actual gain of 7.2% and 14.3% for the years ended December 31, 2014 and 2013, respectively. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

We base our determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2014, we had cumulative gains of approximately $270 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial gains may result in decreases in the future pension costs depending on several factors, including whether such gains at each measurement date exceed the corridor in accordance with "Compensation – Retirement Benefits" accounting guidance.

The method used to determine the discount rate that we utilize for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate as of December 31, 2014 under this method was 4% for the Qualified Plan, 3.9% for the Nonqualified Plans and 4% for the Postretirement Plans. Due to the effect of the unrecognized actuarial gains and based on an expected rate of return on the Pension Plans' assets of 6%, discount rates of 4% and 3.9% and various other assumptions including adoption of updated mortality tables that the Society of Actuaries issued in October 2014, we estimate that the pension costs for the Pension Plans will approximate $129 million, $96 million and $66 million in 2015, 2016 and 2017, respectively. Based on an expected rate of return on the Postretirement Plans' assets of 6.75%, a discount rate of 4% and various other assumptions including adoption of updated mortality tables that the Society of Actuaries issued in October 2014, we estimate credits will approximate $94 million, $98 million and $103 million in 2015, 2016 and 2017, respectively. Future actual costs will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the "Effect if Different Assumptions Used" section below.

The value of the Pension Plans' assets increased to $5 billion as of December 31, 2014 from $4.7 billion as of December 31, 2013 primarily due to investment returns and company contributions in excess of benefit payments. During 2014, the Qualified Plan paid $289 million and the Nonqualified Plans paid $7 million in benefits to plan participants. The value of the Postretirement Plans' assets remained unchanged at $1.7 billion as of December 31, 2014 and 2013 primarily due to investment returns and contributions by the company and the participants offsetting benefit payments. The Postretirement Plans paid $134 million in benefits to plan participants during 2014.

Nature of Estimates Required

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

Assumptions and Approach Used

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

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

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

Effect if Different Assumptions Used

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

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in millions)			
Effect on December 31, 2014 Benefit Obligations				
Discount Rate	$ (282)	$ 311	$ (78)	$ 86
Compensation Increase Rate	20	(19)	NA	NA
Cash Balance Crediting Rate	70	(63)	NA	NA
Health Care Cost Trend Rate	NA	NA	34	(30)
Effect on 2014 Periodic Cost				
Discount Rate	(17)	19	(5)	5
Compensation Increase Rate	5	(4)	NA	NA
Cash Balance Crediting Rate	14	(13)	NA	NA
Health Care Cost Trend Rate	NA	NA	5	(4)
Expected Return on Plan Assets	(22)	22	(8)	8

NA Not applicable.

ACCOUNTING PRONOUNCEMENTS

Pronouncements Adopted in 2015

The FASB issued ASU 2014-08 "Presentation of Financial Statements and Property, Plant and Equipment" changing the presentation of discontinued operations on the statements of income and other requirements for reporting discontinued operations. Under the new standard, a disposal of a component or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results when the component meets the criteria to be classified as held-for-sale or is disposed. The amendments in this update also require additional disclosures about discontinued operations and disposal of an individually significant component of an entity that does not qualify for discontinued operations. We adopted ASU 2014-08 effective January 1, 2015. We expect no impact on the financial statements in the first quarter of 2015.

Pronouncements Effective in the Future

The FASB issued ASU 2014-09 "Revenue from Contracts with Customers" clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016. We are analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on revenue or net income. We plan to adopt ASU 2014-09 effective January 1, 2017.

The FASB issued ASU 2015-01 "Income Statement – Extraordinary and Unusual Items" eliminating the concept of extraordinary items for presentation on the face of the income statement. Under the new standard, a material event or transaction that is unusual in nature, infrequent or both shall be reported as a separate component of income from continuing operations. Alternatively, it may be disclosed in the notes to financial statements. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015. Early adoption is permitted if applied from the beginning of a fiscal year. As applicable, this standard may change the presentation of amounts in the income statements. We plan to adopt ASU 2015-01 effective January 1, 2016.

Future Accounting Changes

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

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

Our Transmission and Distribution Utilities segment is exposed to FTR price risk as it relates to RTO congestion during the June 2012 – May 2015 Ohio ESP period. Additional risks include energy procurement risk and interest rate risk. Our Generation & Marketing segment conducts marketing, risk management and retail activities in ERCOT, PJM and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail electricity. These risks

include commodity price risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates. In addition, our Generation & Marketing segment is also exposed to certain market risks as a major power producer and through its transactions in wholesale electricity, natural gas and coal trading and marketing contracts.

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

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2013:

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2014

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets as of December 31, 2013	$ 32	$ 3	$ 157	$ 192
Gain from Contracts Realized/Settled During the Period and Entered in a Prior Period	(17)	(3)	(39)	(59)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	12	12
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	10	10
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	21	46	—	67
Total MTM Risk Management Contract Net Assets as of December 31, 2014	$ 36	$ 46	$ 140	222
Commodity Cash Flow Hedge Contracts				2
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				(1)
Fair Value Hedge Contracts				(6)
Collateral Deposits				32
Total MTM Derivative Contract Net Assets as of December 31, 2014				$ 249

(a) Reflects fair value on primarily long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.

(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.

(c) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 10 – Derivatives and Hedging and Note 11 – Fair Value Measurements for additional information related to our risk management contracts. The following tables and discussion provide information on our credit risk and market volatility risk.

Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. We use Moody's Investors Service, Standard & Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of December 31, 2014, our credit exposure net of collateral to sub investment grade counterparties was approximately 8.4%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of December 31, 2014, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
			(in millions, except number of counterparties)		
Investment Grade	$ 628	$ 3	$ 625	2	$ 249
Split Rating	21	—	21	1	21
Noninvestment Grade	2	2	—	—	—
No External Ratings:					
Internal Investment Grade	83	—	83	3	41
Internal Noninvestment Grade	83	16	67	2	36
Total as of December 31, 2014	$ 817	$ 21	$ 796	8	$ 347
Total as of December 31, 2013	$ 787	$ 18	$ 769	9	$ 381

In addition, we are exposed to credit risk related to our participation in RTOs. For each of the RTOs in which we participate, this risk is generally determined based on our proportionate share of member gross activity over a specified period of time.

Value at Risk (VaR) Associated with Risk Management Contracts

We use a risk measurement model, which calculates VaR, to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of December 31, 2014, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

The following tables show the end, high, average and low market risk as measured by VaR for the periods indicated:

VaR Model
Trading Portfolio

Twelve Months Ended December 31, 2014				Twelve Months Ended December 31, 2013			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ —	$ 3	$ 1	$ —	$ —	$ 1	$ —	$ —

VaR Model
Non-Trading Portfolio

Twelve Months Ended December 31, 2014			
End	High	Average	Low
(in millions)			
$ 2	$ 3	$ 1	$ —

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

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

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which our interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of December 31, 2014 and 2013, the estimated EaR on our debt portfolio for the following twelve months was $33 million and $32 million, respectively.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 20, 2015 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Columbus, Ohio
February 20, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2014, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2014 of the Company and our report dated February 20, 2015 expressed an unqualified opinion on those financial statements.

Deloitte & Touche LLP

Columbus, Ohio
February 20, 2015

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

Management assessed the effectiveness of AEP's internal control over financial reporting as of December 31, 2014. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO 2013) in Internal Control – Integrated Framework. Based on management's assessment, AEP's internal control over financial reporting was effective as of December 31, 2014.

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

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2014, 2013 and 2012
(in millions, except per-share and share amounts)

	Years Ended December 31,		
	2014	2013	2012
REVENUES			
Vertically Integrated Utilities	$ 9,397	$ 9,347	$ 8,785
Transmission and Distribution Utilities	4,553	4,279	4,659
Generation & Marketing	2,384	1,208	882
Other Revenues	686	523	619
TOTAL REVENUES	17,020	15,357	14,945
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	4,272	4,068	4,111
Purchased Electricity for Resale	2,086	1,491	1,169
Other Operation	3,225	2,904	2,962
Maintenance	1,361	1,179	1,115
Asset Impairments and Other Related Charges	—	226	300
Depreciation and Amortization	1,929	1,743	1,782
Taxes Other Than Income Taxes	915	891	850
TOTAL EXPENSES	13,788	12,502	12,289
OPERATING INCOME	3,232	2,855	2,656
Other Income (Expense):			
Interest and Investment Income	7	58	8
Carrying Costs Income	33	30	53
Allowance for Equity Funds Used During Construction	103	73	93
Interest Expense	(885)	(906)	(988)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	2,490	2,110	1,822
Income Tax Expense	942	684	604
Equity Earnings of Unconsolidated Subsidiaries	90	58	44
NET INCOME	1,638	1,484	1,262
Net Income Attributable to Noncontrolling Interests	4	4	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,634	$ 1,480	$ 1,259
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	488,592,997	486,619,555	484,682,469
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.34	$ 3.04	$ 2.60
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	488,899,840	487,040,956	485,084,694
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.34	$ 3.04	$ 2.60

See Notes to Consolidated Financial Statements beginning on page 65.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2014, 2013 and 2012
(in millions)

	Years Ended December 31,		
	2014	**2013**	**2012**
Net Income	$ 1,638	$ 1,484	$ 1,262
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $3, $8 and $8 in 2014, 2013 and 2012, Respectively	5	15	(15)
Securities Available for Sale, Net of Tax of $0, $1 and $1 in 2014, 2013 and 2012, Respectively	1	3	2
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $3, $12 and $16 in 2014, 2013 and 2012, Respectively	5	22	31
Pension and OPEB Funded Status, Net of Tax of $1, $95 and $62 in 2014, 2013 and 2012, Respectively	1	177	115
TOTAL OTHER COMPREHENSIVE INCOME	12	217	133
TOTAL COMPREHENSIVE INCOME	1,650	1,701	1,395
Total Comprehensive Income Attributable to Noncontrolling Interests	4	4	3
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,646	$ 1,697	$ 1,392

See Notes to Consolidated Financial Statements beginning on page 65.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2014, 2013 and 2012
(in millions)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2011	504	$ 3,274	$ 5,970	$ 5,890	$ (470)	$ 1	$ 14,665
Issuance of Common Stock	2	15	68				83
Common Stock Dividends ($1.88/share)				(913)		(3)	(916)
Other Changes in Equity			11			(1)	10
Net Income				1,259		3	1,262
Other Comprehensive Income					133		133
TOTAL EQUITY – DECEMBER 31, 2012	506	3,289	6,049	6,236	(337)	—	15,237
Issuance of Common Stock	2	14	70				84
Common Stock Dividends ($1.95/share)				(950)		(4)	(954)
Other Changes in Equity			12			1	13
Net Income				1,480		4	1,484
Other Comprehensive Income					217		217
Pension and OPEB Adjustment Related to Mitchell Plant					5		5
TOTAL EQUITY – DECEMBER 31, 2013	508	3,303	6,131	6,766	(115)	1	16,086
Issuance of Common Stock	2	10	63				73
Common Stock Dividends ($2.03/share)				(994)		(4)	(998)
Other Changes in Equity			10			3	13
Net Income				1,634		4	1,638
Other Comprehensive Income					12		12
TOTAL EQUITY – DECEMBER 31, 2014	510	$ 3,313	$ 6,204	$ 7,406	$ (103)	$ 4	$ 16,824

See Notes to Consolidated Financial Statements beginning on page 65.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2014 and 2013
(in millions)

	December 31, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$ 163	$ 118
Other Temporary Investments (December 31, 2014 and 2013 Amounts Include $371 and $335, Respectively, Related to Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and EIS)	386	353
Accounts Receivable:		
Customers	727	746
Accrued Unbilled Revenues	146	157
Pledged Accounts Receivable – AEP Credit	987	945
Miscellaneous	87	72
Allowance for Uncollectible Accounts	(21)	(60)
Total Accounts Receivable	1,926	1,860
Fuel	587	701
Materials and Supplies	738	722
Risk Management Assets	178	160
Regulatory Asset for Under-Recovered Fuel Costs	127	80
Margin Deposits	95	70
Prepayments and Other Current Assets	278	246
TOTAL CURRENT ASSETS	4,478	4,310
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	25,727	25,074
Transmission	12,433	10,893
Distribution	17,157	16,377
Other Property, Plant and Equipment (Including Plant to be Retired, Coal Mining and Nuclear Fuel)	5,770	5,470
Construction Work in Progress	3,218	2,471
Total Property, Plant and Equipment	64,305	60,285
Accumulated Depreciation and Amortization	20,188	19,288
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	44,117	40,997
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,264	4,376
Securitized Assets	2,072	2,373
Spent Nuclear Fuel and Decommissioning Trusts	2,096	1,932
Goodwill	91	91
Long-term Risk Management Assets	294	297
Deferred Charges and Other Noncurrent Assets	2,221	2,038
TOTAL OTHER NONCURRENT ASSETS	11,038	11,107
TOTAL ASSETS	$ 59,633	$ 56,414

See Notes to Consolidated Financial Statements beginning on page 65.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2014 and 2013
(dollars in millions)

	December 31, 2014	December 31, 2013
CURRENT LIABILITIES		
Accounts Payable	$ 1,287	$ 1,266
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	744	700
Other Short-term Debt	602	57
Total Short-term Debt	1,346	757
Long-term Debt Due Within One Year (December 31, 2014 and 2013 Amounts Include $431 and $416, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Sabine)	2,503	1,549
Risk Management Liabilities	92	90
Customer Deposits	324	299
Accrued Taxes	871	822
Accrued Interest	239	245
Regulatory Liability for Over-Recovered Fuel Costs	55	119
Other Current Liabilities	1,250	965
TOTAL CURRENT LIABILITIES	7,967	6,112
NONCURRENT LIABILITIES		
Long-term Debt (December 31, 2014 and 2013 Amounts Include $2,260 and $2,532, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy and Sabine)	16,181	16,828
Long-term Risk Management Liabilities	131	177
Deferred Income Taxes	10,986	10,300
Regulatory Liabilities and Deferred Investment Tax Credits	3,892	3,694
Asset Retirement Obligations	1,951	1,835
Employee Benefits and Pension Obligations	630	415
Deferred Credits and Other Noncurrent Liabilities	1,071	967
TOTAL NONCURRENT LIABILITIES	34,842	34,216
TOTAL LIABILITIES	42,809	40,328
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		
	2014 / 2013	
Shares Authorized	600,000,000 / 600,000,000	
Shares Issued	509,739,159 / 508,113,964	
(20,336,592 Shares were Held in Treasury as of December 31, 2014 and 2013)	3,313	3,303
Paid-in Capital	6,204	6,131
Retained Earnings	7,406	6,766
Accumulated Other Comprehensive Income (Loss)	(103)	(115)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	16,820	16,085
Noncontrolling Interests	4	1
TOTAL EQUITY	16,824	16,086
TOTAL LIABILITIES AND EQUITY	$ 59,633	$ 56,414

See Notes to Consolidated Financial Statements beginning on page 65.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014, 2013 and 2012
(in millions)

	Years Ended December 31,		
	2014	2013	2012
OPERATING ACTIVITIES			
Net Income	$ 1,638	$ 1,484	$ 1,262
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,929	1,743	1,782
Deferred Income Taxes	878	709	636
Asset Impairments and Other Related Charges	—	226	300
Carrying Costs Income	(33)	(30)	(53)
Allowance for Equity Funds Used During Construction	(103)	(73)	(93)
Mark-to-Market of Risk Management Contracts	(53)	38	57
Amortization of Nuclear Fuel	144	131	136
Pension and Postemployment Benefit Reserves	80	172	120
Pension Contributions to Qualified Plan Trust	(71)	—	(200)
Property Taxes	(42)	(35)	(19)
Fuel Over/Under-Recovery, Net	(36)	62	157
Deferral of Ohio Capacity Costs, Net	(114)	(214)	(65)
Change in Other Noncurrent Assets	26	(184)	(171)
Change in Other Noncurrent Liabilities	242	(169)	7
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(72)	5	(16)
Fuel, Materials and Supplies	102	122	(224)
Accounts Payable	(80)	95	(60)
Accrued Taxes, Net	4	85	174
Other Current Assets	(36)	5	(3)
Other Current Liabilities	210	(66)	77
Net Cash Flows from Operating Activities	4,613	4,106	3,804
INVESTING ACTIVITIES			
Construction Expenditures	(4,134)	(3,624)	(3,025)
Change in Other Temporary Investments, Net	(31)	(11)	(27)
Purchases of Investment Securities	(1,088)	(927)	(1,047)
Sales of Investment Securities	1,032	858	988
Acquisitions of Nuclear Fuel	(116)	(154)	(107)
Acquisitions of Assets/Businesses	(65)	(32)	(94)
Insurance Proceeds Related to Cook Plant Fire	—	72	—
Proceeds from Sales of Assets	6	21	18
Other Investing Activities	(10)	(21)	(97)
Net Cash Flows Used for Investing Activities	(4,406)	(3,818)	(3,391)
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	73	84	83
Issuance of Long-term Debt	2,067	3,207	2,856
Commercial Paper and Credit Facility Borrowings	—	17	25
Change in Short-term Debt, Net	589	(221)	(654)
Retirement of Long-term Debt	(1,780)	(2,598)	(1,643)
Commercial Paper and Credit Facility Repayments	—	(20)	(40)
Proceeds from Nuclear Fuel Sale/Leaseback	—	110	—
Principal Payments for Capital Lease Obligations	(120)	(82)	(71)
Dividends Paid on Common Stock	(998)	(954)	(916)
Other Financing Activities	7	8	5
Net Cash Flows Used for Financing Activities	(162)	(449)	(355)
Net Increase (Decrease) in Cash and Cash Equivalents	45	(161)	58
Cash and Cash Equivalents at Beginning of Period	118	279	221
Cash and Cash Equivalents at End of Period	$ 163	$ 118	$ 279

See Notes to Consolidated Financial Statements beginning on page 65.

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

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

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

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

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

Corporate Separation

Background

On December 31, 2013, as approved by the FERC and the PUCO, OPCo transferred its generation assets and related generation liabilities at net book value to AGR. In accordance with Ohio law, OPCo remains responsible to provide power and capacity to OPCo customers who have not switched electric providers. Effective January 1, 2014, OPCo began purchasing power from both affiliated and nonaffiliated entities, subject to PUCO approval, to meet the energy and capacity needs of customers. On December 31, 2013, subsequent to the transfer of OPCo's generation assets and associated liabilities to AGR, AGR transferred at net book value its ownership (867 MW) in Amos Plant, Unit 3 to APCo and one-half of its interest (780 MW) in the Mitchell Plant to KPCo.

Other Impacts of Corporate Separation

The Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated.

Effective January 1, 2014, the FERC approved:

- A PCA among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Under the PCA, APCo, I&M and KPCo are individually responsible for planning their respective capacity obligations and there are no capacity equalization charges/credits under the PCA on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo, I&M and KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.
- A Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies will fulfill their existing obligations under the PJM Reliability Assurance Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR is committed to use its capacity to help meet the PJM capacity obligations of member companies through May 31, 2015.

- A Power Supply Agreement (PSA) between AGR and OPCo for AGR to supply capacity for OPCo's switched (at $188.88/MW day) and non-switched retail load for the period January 1, 2014 through May 31, 2015 and to supply the energy needs of OPCo's non-switched retail load that was not acquired through auctions in 2014.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

Our public utility subsidiaries' rates are regulated by the FERC and state regulatory commissions in our eleven state operating territories. The FERC also regulates our affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of our public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires a nonregulated affiliate to bill an affiliated public utility company at no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. The state regulatory commissions also regulate certain intercompany transactions under various orders and affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets and wholesale power transactions. Our wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when we negotiate and file a cost-based contract with the FERC or the FERC determines that we have "market power" in the region where the transaction occurs. We have entered into wholesale power supply contracts with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually.

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

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

In addition, the FERC regulates the SIA, the Operating Agreement, the Transmission Agreement and the Transmission Coordination Agreement, all of which are still active and allocate shared system costs and revenues among the utility subsidiaries that are parties to each agreement. In accordance with our October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated. In December 2013, the FERC issued orders approving the creation of a PCA, effective January 1, 2014. Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent. Effective June 1, 2014, the FERC approved the cancellation of the System Transmission Integration Agreement.

Principles of Consolidation

Our consolidated financial statements include our wholly-owned and majority-owned subsidiaries and VIEs of which we are the primary beneficiary. Intercompany items are eliminated in consolidation. We use the equity method of accounting for equity investments where we exercise significant influence but do not hold a controlling financial interest. Such investments are initially recorded at cost in Deferred Charges and Other Noncurrent Assets on the balance sheets. Our proportionate share of the investee's equity earnings is included in Equity Earnings of Unconsolidated Subsidiaries on the statements of income. Equity method investments are required to be tested for impairment when it is determined there may be an other-than-temporary loss in value. We have ownership interests in generating units that are jointly-owned. Our proportionate share of the operating costs associated with such facilities is included on the statements of income and our proportionate share of the assets and liabilities are reflected on the balance sheets.

Accounting for the Effects of Cost-Based Regulation

As the owner of rate-regulated electric public utility companies, our financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," we record regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

Use of Estimates

The preparation of these financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for doubtful accounts, goodwill, intangible and long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Other Temporary Investments

Other Temporary Investments include funds held by trustees primarily for the payment of securitization bonds and securities available for sale, including marketable securities that we intend to hold for less than one year and investments by our protected cell of EIS.

We classify our investments in marketable securities as available-for-sale or held-to-maturity in accordance with the provisions of "Investments – Debt and Equity Securities" accounting guidance. We do not have any investments classified as trading.

Available-for-sale securities reflected in Other Temporary Investments are carried at fair value with the unrealized gain or loss, net of tax, reported in AOCI. Held-to-maturity securities reflected in Other Temporary Investments are carried at amortized cost. The cost of securities sold is based on the specific identification or weighted average cost method.

In evaluating potential impairment of securities with unrealized losses, we considered, among other criteria, the current fair value compared to cost, the length of time the security's fair value has been below cost, our intent and ability to retain the investment for a period of time sufficient to allow for any anticipated recovery in value and current economic conditions. See "Fair Value Measurements of Other Temporary Investments" in Note 11.

Inventory

Fossil fuel inventories are generally carried at average cost with the exception of AGR and TNC which are carried at the lower of average cost or market. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to our risk management activities and customer receivables primarily related to other revenue-generating activities.

We recognize revenue from electric power sales when we deliver power to our customers. To the extent that deliveries have occurred but a bill has not been issued, we accrue and recognize, as Accrued Unbilled Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, for I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the billed and unbilled receivables AEP Credit acquires from affiliated utility subsidiaries.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from participating AEP subsidiaries. For receivables related to APCo's West Virginia operations, the bad debt reserve is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable. For customer accounts receivables related to our risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For the wires business of TCC and TNC, bad debt reserves are calculated using the specific identification of receivable balances greater than 120 days delinquent, and for those balances less than 120 days where the collection is doubtful. For miscellaneous accounts receivable, bad debt expense is recorded for all amounts outstanding 180 days or greater at 100%, unless specifically identified. Miscellaneous accounts receivable items open less than 180 days may be reserved using specific identification for bad debt reserves.

Emission Allowances

In regulated jurisdictions, we record emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. For our nonregulated business, we record allowances at the lower of cost or market. We follow the inventory model for these allowances. We record allowances expected to be consumed within one year in Materials and Supplies and allowances with expected consumption beyond one year in Deferred Charges and Other Noncurrent Assets on the balance sheets. We record the consumption of allowances in the production of energy in Fuel and Other Consumables Used for Electric Generation on the statements of income at an average cost. We report the purchases and sales of allowances in the Operating Activities section of the statements of cash flows. We record the net margin on sales of emission allowances in Vertically Integrated Utilities Revenue on the statements of income because of its integral nature to the production process of energy and our revenue optimization strategy for our utility operations. The net margin on sales of emission allowances affects the determination of deferred fuel or deferred emission allowance costs and the amortization of regulatory assets for certain jurisdictions.

Property, Plant and Equipment

Regulated

Electric utility property, plant and equipment for our rate-regulated operations are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of removal cost incurred and salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities. The costs of labor, materials and overhead incurred to operate and maintain our plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense.

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Nonregulated

Our nonregulated operations generally follow the policies of our rate-regulated operations listed above but with the following exceptions. Property, plant and equipment of nonregulated operations are stated at fair value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for most nonregulated operations under the group composite method of depreciation. For nonregulated plant assets, a gain or loss would be recorded if the retirement is not considered an interim routine replacement. Removal costs are charged to expense.

Allowance for Funds Used During Construction and Interest Capitalization

For regulated operations, AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. We record the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense. For nonregulated operations, including certain generating assets, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest."

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable, Accounts Payable and Short-term Debt approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

Fair Value Measurements of Assets and Liabilities

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. The amount of risk taken is determined by the Commercial Operations, Energy Supply and Finance groups in accordance with our established risk management policies as approved by the Finance Committee of our Board of Directors. Our market risk oversight staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) and the Energy Supply Risk Committee (Competitive Risk Committee) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer. The Competitive Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer and Chief Risk Officer in addition to Energy Supply's President and Vice President.

For our commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. We verify our price curves using these broker quotes and classify these fair values within Level 2 when substantially all of the fair value can be corroborated. We typically obtain multiple broker quotes, which are nonbinding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, we average the quoted bid and ask prices. In certain circumstances, we may discard a broker quote if it is a clear outlier. We use a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated we include these locations within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of our contracts being classified as Level 3 is the inability to substantiate our energy price curves in the market. A significant portion of our Level 3 instruments have been economically hedged which greatly limits potential earnings volatility.

We utilize our trustee's external pricing service in our estimate of the fair value of the underlying investments held in the benefit plan and nuclear trusts. Our investment managers review and validate the prices utilized by the trustee to determine fair value. We perform our own valuation testing to verify the fair values of the securities. We receive audit reports of our trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts.

Assets in the benefits and nuclear trusts, Cash and Cash Equivalents and Other Temporary Investments are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities and cash equivalents funds. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by

securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Benefit plan assets included in Level 3 are primarily real estate and private equity investments that are valued using methods requiring judgment including appraisals. The fair value of real estate investments is measured using market capitalization rates, recent sales of comparable investments and independent third-party appraisals. The fair value of private equity investments is measured using cost and purchase multiples, operating results, discounted future cash flows and market based comparable data. Depending on the specific situation, one or multiple approaches are used to determine the valuation of a real estate or private equity investment.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily on the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as current regulatory assets. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a phase-in plan or the FAC has been suspended. These deferrals are amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit our fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a FAC under-recovery is no longer probable of recovery, we adjust our FAC deferrals and record provisions for estimated refunds to recognize these probable outcomes.

Changes in fuel costs, including purchased power in Kentucky for KPCo, in Indiana and Michigan for I&M, in Ohio (through the ESP related to standard service offer load served) for OPCo, in Arkansas, Louisiana and Texas for SWEPCo, in Oklahoma for PSO and in Virginia and West Virginia (upon securitization in November 2013) for APCo are reflected in rates in a timely manner generally through the FAC. Changes in fuel costs, including purchased power in Ohio (from 2009 through 2011) for OPCo and in West Virginia (prior to securitization in November 2013) for APCo are reflected in rates through FAC phase-in plans. The FAC generally includes some sharing of off-system sales margins. In West Virginia for APCo, all of the margins from off-system sales are given to customers through the FAC. Prior to corporate separation, none of the margins from off-system sales were given to customers through the FAC in Ohio for OPCo. A portion of margins from off-system sales are given to customers through the FAC and other rate mechanisms in Oklahoma for PSO, Arkansas, Louisiana and Texas for SWEPCo, Virginia for APCo and in Indiana and Michigan for I&M. Where the FAC or off-system sales sharing mechanism is capped, frozen or non-existent, changes in fuel costs or sharing of off-system sales impact earnings.

Revenue Recognition

Regulatory Accounting

Our financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheets. We test for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against income.

Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. For regulated and nonregulated operations, we recognize the revenues on the statements of income upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

Most of the power produced at our generation plants is sold to PJM or SPP. We also purchase power from PJM and SPP to supply our customers. Generally, these power sales and purchases for the regulated subsidiaries are reported on a net basis as revenues on the statements of income. However, purchases of power in excess of sales to PJM or SPP, on an hourly net basis, used to serve retail load are recorded gross as Purchased Electricity for Resale on the statements of income. With the exception of certain dedicated load bilateral power supply contracts, the transactions of our nonregulated subsidiaries are reported as gross purchases or sales.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's facts and circumstances. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Purchased Electricity for Resale on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, we record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

We engage in wholesale power, coal and natural gas marketing and risk management activities focused on wholesale markets where we own assets and adjacent markets. Our activities include the purchase and sale of energy under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. We engage in certain energy marketing and risk management transactions with RTOs.

We recognize revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. We use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or a normal purchase or sale. We include unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM in revenues or expense on the transaction's facts and circumstances. In jurisdictions subject to cost-based regulation, we defer unrealized MTM amounts and some realized gains and losses as regulatory assets (for losses) and regulatory liabilities (for gains). We include unrealized MTM gains and losses resulting from derivative contracts on the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying wholesale marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). We initially record the effective portion of the cash flow hedge's gain or loss as a component of AOCI. When the forecasted transaction is realized and affects net income, we subsequently reclassify the gain or loss on the hedge from AOCI into revenues or expenses

within the same financial statement line item as the forecasted transaction on the statements of income. Excluding those jurisdictions subject to cost-based regulation, we recognize the ineffective portion of the gain or loss in revenues or expense immediately on the statements of income, depending on the specific nature of the associated hedged risk. In regulated jurisdictions, we defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Accounting for Cash Flow Hedging Strategies" section of Note 10.

Barging Activities

AEP River Operations' revenue is recognized based on percentage of voyage completion. The proportion of freight transportation revenue to be recognized is determined by applying a percentage to the contractual charges for such services. The percentage is determined by dividing the number of miles from the loading point to the position of the barge as of the end of the accounting period by the total miles to the destination specified in the customer's freight contract. The position of the barge at accounting period end is determined by our computerized barge tracking system.

SPP Integrated Power Market

In March 2014, SPP changed from an energy imbalance service market to a fully integrated power market. In the past, PSO and SWEPCo would satisfy their load requirements with their own generation resources or through the Operating Agreement. In the new integrated power market, PSO and SWEPCo operate as standalone entities by offering their respective generation into the SPP power market, which then economically dispatches the resources. This change further enables retail customers to obtain power through either internal generation or power purchases from the SPP market. The new integrated power market now operates in a similar manner as the PJM power market for the AEP East Companies. The change in the SPP integrated power market did not have a significant effect on the 2014 results of operations or cash flows.

Levelization of Nuclear Refueling Outage Costs

In accordance with regulatory orders, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over the period beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins. I&M adjusts the amortization amount as necessary to ensure full amortization of all deferred costs by the end of the refueling cycle.

Maintenance

We expense maintenance costs as incurred. If it becomes probable that we will recover specifically-incurred costs through future rates, we establish a regulatory asset to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. In certain regulatory jurisdictions, we defer costs above the level included in base rates and amortize those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment Tax Credits

We use the liability method of accounting for income taxes. Under the liability method, we provide deferred income taxes for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), we record deferred income taxes and establish related regulatory assets and liabilities to match the regulated revenues and tax expense.

We account for investment tax credits under the flow-through method except where regulatory commissions reflect investment tax credits in the rate-making process on a deferral basis. We amortize deferred investment tax credits over the life of the plant investment.

We account for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." We classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation expense.

Excise Taxes

We act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on our customers. We do not recognize these taxes as revenue or expense.

Debt

We defer gains and losses from the reacquisition of debt used to finance regulated electric utility plants and amortize the deferral over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If we refinance the reacquired debt associated with the regulated business, the reacquisition costs attributable to the portions of the business subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Operations not subject to cost-based rate regulation report gains and losses on the reacquisition of debt in Interest Expense on the statements of income upon reacquisition.

We defer debt discount or premium and debt issuance expenses and amortize generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. We include the net amortization expense in Interest Expense on the statements of income.

Goodwill and Intangible Assets

When we acquire businesses, we record the fair value of all assets and liabilities, including intangible assets. To the extent that consideration exceeds the fair value of identified assets, we record goodwill. We do not amortize goodwill and intangible assets with indefinite lives. We test acquired goodwill and other intangible assets with indefinite lives for impairment at least annually at their estimated fair value. We test goodwill at the reporting unit level and other intangibles at the asset level. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods. We amortize intangible assets with finite lives over their respective estimated lives to their estimated residual values. We also review the lives of the amortizable intangibles with finite lives on an annual basis.

Investments Held in Trust for Future Liabilities

We have several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and spent nuclear fuel disposal. All of our trust funds' investments are diversified and managed in compliance with all laws and regulations. Our investment strategy for trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. We regularly review the actual asset allocations and periodically rebalance the investments to targeted allocations when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for our benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The investment policy for the pension fund allocates assets based on the funded status of the pension plan. The objective of the asset allocation policy is to reduce the investment volatility of the plan over time. Generally, more of the investment mix will be allocated to fixed income investments as the plan becomes better funded. Assets will be transferred away from equity investments into fixed income investments based on the market value of plan assets compared to the plan's projected benefit obligation. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	30.0%
Fixed Income	55.0%
Other Investments	15.0%

OPEB Plans Assets	Target
Equity	65.0%
Fixed Income	33.0%
Cash	2.0%

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, our investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law. Each investment manager's portfolio is compared to a diversified benchmark index.

For equity investments, the limits are as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No individual stock may be more than 10% and 7% for pension and OPEB investments, respectively, of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, the concentration limits must not exceed:

- 3% in any single issuer.
- 5% for private placements.
- 5% for convertible securities.
- 60% for bonds rated AA+ or lower.
- 50% for bonds rated A+ or lower.
- 10% for bonds rated BBB- or lower.

For obligations of non-government issuers within the fixed income portfolio, the following limitations apply:

- AAA rated debt: a single issuer should account for no more than 5% of the portfolio.
- AA+, AA, AA- rated debt: a single issuer should account for no more than 3% of the portfolio.
- Debt rated A+ or lower: a single issuer should account for no more than 2% of the portfolio.
- No more than 10% of the portfolio may be invested in high yield and emerging market debt combined at any time.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and development risk classifications and some investments in Real Estate Investment Trusts (REITs), which are publicly traded real estate securities.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships and commingled funds to invest across the private equity investment spectrum. Our private equity holdings are with multiple general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investment instruments. Commingled private equity funds are used to enhance the holdings' diversity.

We participate in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. We lend securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is providing modest incremental income with a limited increase in risk.

We hold trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association (VEBA) trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

We maintain trust records for each regulatory jurisdiction. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

We record securities held in these trust funds as Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets. We record these securities at fair value. We classify securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments for investments in both debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the debt and equity investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. We record unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. See the "Nuclear Contingencies" section of Note 6 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Stock-Based Compensation Plans

As of December 31, 2014, we had performance units and restricted stock units outstanding under the Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP). This plan was last approved by shareholders in April 2010. Upon vesting, performance units are paid in cash and restricted stock units are settled in AEP Common Shares, except for restricted stock units granted after January 1, 2013 and vesting to executive officers, which are paid in cash.

We maintain a variety of tax qualified and nonqualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP common stock. This includes career share accounts maintained under the American Electric Power System Stock Ownership Requirement Plan, which facilitates executives in meeting minimum stock ownership requirements assigned to them by the Human Resources Committee of the Board of Directors. Career shares are derived from vested performance units granted to employees under the LTIP. Career shares are equal in value to shares of AEP common stock and become payable to executives in cash after their service ends. Career shares accrue additional dividend shares in an amount equal to dividends paid on AEP Common shares, and are reinvested in such shares at the closing market price on the dividend payments date.

We compensate our non-employee directors, in part, with stock units under the American Electric Power Company, Inc. Stock Unit Accumulation Plan for Non-Employee Directors. These stock units become payable in cash to directors after their service ends.

We measure and recognize compensation expense for all share-based payment awards to employees and directors, including stock options, based on estimated fair values. For share-based payment awards with service only vesting conditions, we recognize compensation expense using the straight-line single-option method. Stock-based compensation expense recognized on the statements of income for the years ended December 31, 2014, 2013 and 2012 is based on awards ultimately expected to vest. Therefore, stock-based compensation expense has been reduced to reflect estimated forfeitures. Accounting guidance for "Compensation - Stock Compensation" requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

For the years ended December 31, 2014, 2013 and 2012, compensation expense is included in Net Income for the performance units, career shares, restricted stock units and the non-employee director's stock units. See Note 15 for additional discussion.

Earnings Per Share (EPS)

Shown below are income statement amounts attributable to AEP common shareholders:

Amounts Attributable to AEP Common Shareholders	Years Ended December 31, 2014	2013	2012
		(in millions)	
Net Income	$ 1,638	$ 1,484	$ 1,262
Net Income Attributable to Noncontrolling Interests	4	4	3
Earnings Attributable to AEP Common Shareholders	$ 1,634	$ 1,480	$ 1,259

Basic EPS is calculated by dividing net earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

The following table presents our basic and diluted EPS calculations included on the statements of income:

	Years Ended December 31,					
	2014		2013		2012	
	(in millions, except per share data)					
		$/share		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 1,634		$ 1,480		$ 1,259	
Weighted Average Number of Basic Shares Outstanding	488.6	$ 3.34	486.6	$ 3.04	484.7	$ 2.60
Weighted Average Dilutive Effect of Restricted Stock Units	0.3	—	0.4	—	0.4	—
Weighted Average Number of Diluted Shares Outstanding	488.9	$ 3.34	487.0	$ 3.04	485.1	$ 2.60

There were no antidilutive shares outstanding as of December 31, 2014, 2013 and 2012.

OPCo Revised Depreciation Rates

Effective December 1, 2011, we revised book depreciation rates for certain of OPCo's generation plants consistent with shortened depreciable lives for the generating units. This change in depreciable lives resulted in a $52 million increase in depreciation expense in 2012.

In the fourth quarter of 2012, we impaired certain Ohio generating units (see Note 7). As a result of this impairment of the full book value of these assets, we ceased depreciation on these generating units effective December 1, 2012.

In the second quarter of 2013, we impaired Muskingum River Plant, Unit 5 (MR5). As a result of this impairment of the full book value of this generating unit, we ceased depreciation on MR5 effective July 1, 2013.

The effect of these revised depreciation rates and impairments is reported in the Generation & Marketing segment.

Supplementary Related Party Information

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2014, AEP's ownership and investment in OVEC were 43.47% and $4.4 million, respectively.

OVEC's owners are members to an intercompany power agreement. Participants of this agreement are entitled to receive and obligated to pay for all OVEC generating capacity, approximately 2,200 MWs, in proportion to their respective power participation ratios. The aggregate power participation ratio of certain AEP utility subsidiaries is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and provide a return on capital. The intercompany power agreement ends in June 2040.

AEP and other nonaffiliated owners authorized environmental investments related to their ownership interests. OVEC financed capital expenditures totaling $1.3 billion in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at its two generation plants. These environmental projects were funded through debt issuances. As of December 31, 2014, both generation plants were operating with environmental controls.

The following details related party transactions for the years ended December 31, 2014, 2013 and 2012:

Related Party Transactions	Years Ended December 31, 2014	2013	2012
		(in millions)	
AEP Consolidated Revenues – Other Revenues:			
OVEC – Barging and Other Transportation Services	$ 24	$ 21	$ 30
AEP Consolidated Expenses – Purchased Electricity for Resale:			
OVEC	268	289	273

Supplementary Income Statement Information

The following table provides the components of Depreciation and Amortization for the years ended December 31, 2014, 2013 and 2012:

Depreciation and Amortization	Years Ended December 31, 2014	2013	2012
		(in millions)	
Depreciation and Amortization of Property, Plant and Equipment	$ 1,605	$ 1,472	$ 1,505
Amortization of Certain Securitized Assets	310	248	224
Amortization of Regulatory Assets and Liabilities	14	23	53
Total Depreciation and Amortization	$ 1,929	$ 1,743	$ 1,782

Supplementary Cash Flow Information

Cash Flow Information	Years Ended December 31, 2014	2013	2012
		(in millions)	
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 838	$ 882	$ 931
Income Taxes	117	(55)	(82)
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	135	182	63
Construction Expenditures Included in Current Liabilities as of December 31,	559	492	439
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	45	—	35
Assumption of Liabilities Related to Acquisitions	—	—	56
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	3	4	30

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, we review the new accounting literature to determine its relevance, if any, to our business. The following final pronouncements will impact our financial statements.

ASU 2014-08 "Presentation of Financial Statements and Property, Plant and Equipment" (ASU 2014-08)

In April 2014, the FASB issued ASU 2014-08 changing the presentation of discontinued operations on the statements of income and other requirements for reporting discontinued operations. Under the new standard, a disposal of a component or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results when the component meets the criteria to be classified as held-for-sale or is disposed. The amendments in this update also require additional disclosures about discontinued operations and disposal of an individually significant component of an entity that does not qualify for discontinued operations. This standard must be prospectively applied to all reporting periods presented in financial reports issued after the effective date.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014. If applicable, this standard will change the presentation of our financial statements but will not affect the calculation of net income, comprehensive income or earnings per share. We adopted ASU 2014-08 effective January 1, 2015. We expect no impact on the financial statements in the first quarter of 2015.

ASU 2014-09 "Revenue from Contracts with Customers" (ASU 2014-09)

In May 2014, the FASB issued ASU 2014-09 clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016. Early adoption is not permitted. As applicable, this standard may change the amount of revenue recognized in the income statements in each reporting period. We are analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on revenue or net income. We plan to adopt ASU 2014-09 effective January 1, 2017.

ASU 2015-01 "Income Statement – Extraordinary and Unusual Items" (ASU 2015-01)

In January 2015, the FASB issued ASU 2015-01 eliminating the concept of extraordinary items for presentation on the face of the income statement. Under the new standard, a material event or transaction that is unusual in nature, infrequent or both shall be reported as a separate component of income from continuing operations. Alternatively, it may be disclosed in the notes to financial statements.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015. Early adoption is permitted if applied from the beginning of a fiscal year. As applicable, this standard may change the presentation of amounts in the income statements. We plan to adopt ASU 2015-01 effective January 1, 2016.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the years ended December 31, 2014 and 2013. All amounts in the following tables are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2014

	Cash Flow Hedges			Pension and OPEB		
	Commodity	Interest Rate and Foreign Currency	Securities Available for Sale	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)			
Balance in AOCI as of December 31, 2013	$ —	$ (23)	$ 7	$ 134	$ (233)	$ (115)
Change in Fair Value Recognized in AOCI	(10)	—	1	—	1	(8)
Amounts Reclassified from AOCI	11	4	—	5	—	20
Net Current Period Other Comprehensive Income	1	4	1	5	1	12
Balance in AOCI as of December 31, 2014	$ 1	$ (19)	$ 8	$ 139	$ (232)	$ (103)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2013

	Cash Flow Hedges			Pension and OPEB		
	Commodity	Interest Rate and Foreign Currency	Securities Available for Sale	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)			
Balance in AOCI as of December 31, 2012	$ (8)	$ (30)	$ 4	$ 112	$ (415)	$ (337)
Change in Fair Value Recognized in AOCI	10	2	3	—	177	192
Amounts Reclassified from AOCI	(2)	5	—	22	—	25
Net Current Period Other Comprehensive Income	8	7	3	22	177	217
Pension and OPEB Adjustment Related to Mitchell Plant	—	—	—	—	5	5
Balance in AOCI as of December 31, 2013	$ —	$ (23)	$ 7	$ 134	$ (233)	$ (115)

Reclassifications from Accumulated Other Comprehensive Income

The following table provides details of reclassifications from AOCI for the years ended December 31, 2014 and 2013. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 8 for additional details.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Years Ended December 31, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI	
	Years Ended December 31,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in millions)	
Commodity:		
Vertically Integrated Utilities Revenues	$ —	$ (1)
Generation & Marketing Revenues	59	(10)
Purchased Electricity for Resale	(39)	8
Regulatory Assets/(Liabilities), Net (a)	(3)	—
Subtotal – Commodity	17	(3)
Interest Rate and Foreign Currency:		
Interest Expense	6	7
Subtotal – Interest Rate and Foreign Currency	6	7
Reclassifications from AOCI, before Income Tax (Expense) Credit	23	4
Income Tax (Expense) Credit	8	1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	15	3
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(21)	(21)
Amortization of Actuarial (Gains)/Losses	29	55
Reclassifications from AOCI, before Income Tax (Expense) Credit	8	34
Income Tax (Expense) Credit	3	12
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	5	22
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 20	$ 25

(a) Represents realized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

The following table provides details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets and the reasons for changes in cash flow hedges for the year ended December 31, 2012. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2012

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2011	$ (3)	$ (20)	$ (23)
Changes in Fair Value Recognized in AOCI	(15)	(14)	(29)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Vertically Integrated Utilities Revenues	—	—	—
Generation & Marketing Revenues	(5)	—	(5)
Purchased Electricity for Resale	13	—	13
Other Operation Expense	—	—	—
Maintenance Expense	—	—	—
Interest Expense	—	4	4
Property, Plant and Equipment	—	—	—
Regulatory Assets (a)	2	—	2
Balance in AOCI as of December 31, 2012	$ (8)	$ (30)	$ (38)

(a) Represents realized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

The following table provides details of changes in unrealized gains and losses related to securities available for sale and the reasons for changes for the year ended December 31, 2012. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Securities Available for Sale
Year Ended December 31, 2012

	(in millions)
Balance in AOCI as of December 31, 2011	$ 2
Changes in Fair Value Recognized in AOCI	2
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income:	
Interest Income	—
Balance in AOCI as of December 31, 2012	$ 4

4. RATE MATTERS

Our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. Rate matters can have a material impact on net income, cash flows and possibly financial condition. Our recent significant rate orders and pending rate filings are addressed in this note.

OPCo Rate Matters

Ohio Electric Security Plan Filings

2009 – 2011 ESP

The PUCO issued an order in March 2009 that modified and approved the ESP which established rates at the start of the April 2009 billing cycle through 2011. OPCo collected the 2009 annualized revenue increase over the last nine months of 2009. The order also provided a phase-in FAC, which was authorized to be recovered through a non-bypassable surcharge over the period 2012 through 2018. The PUCO's March 2009 order was appealed to the Supreme Court of Ohio, which issued an opinion and remanded certain issues back to the PUCO.

In October 2011, the PUCO issued an order in the remand proceeding, which was subsequently appealed. In February 2014, the Supreme Court of Ohio affirmed the PUCO's decision and rejected all appeals.

In August 2012, the PUCO issued an order in a separate proceeding which implemented a PIRR to recover deferred fuel costs in rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. In November 2012, OPCo appealed that PUCO order to the Supreme Court of Ohio claiming a long-term debt rate modified the previously adjudicated 2009 - 2011 ESP order, which granted a weighted average cost of capital (WACC) rate. In November 2012, the IEU and the Ohio Consumers' Counsel (OCC) also filed appeals of the PUCO decision which principally argued that the PUCO should have reduced the deferred fuel balance to reflect the prior "improper" collection of POLR revenues. IEU's appeal also argued that carrying costs should be reduced due to an accumulated deferred income tax credit which, as of December 31, 2014, could reduce carrying costs by $26 million including $14 million of unrecognized equity carrying costs. In December 2014, IEU filed a motion to withdraw its argument related to the collection of POLR revenues. In January 2015, the OCC filed a request to dismiss its appeal altogether. Oral arguments at the Supreme Court of Ohio were held in February 2015. OPCo argued for a remand to reinstate the WACC carrying charges initially approved by the PUCO and challenged the IEU argument that the carrying charges should be reduced due to an accumulated deferred income tax credit. A decision from the Supreme Court of Ohio is pending.

Management is unable to predict the outcome of the unresolved litigation discussed above. Depending on the rulings in these proceedings, it could reduce future net income and cash flows and impact financial condition.

June 2012 – May 2015 ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that established base generation rates through May 2015. This ruling was generally upheld in rehearing orders in January and March 2013.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the RPM price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The OPCo RPM price collected from CRES providers, which includes reserve margins, was approximately $34/MW day through May 2014 and is $150/MW day from June 2014 through May 2015. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio.

As part of the August 2012 ESP order, the PUCO established a non-bypassable RSR, effective September 2012. The RSR was collected from customers at $3.50/MWh through May 2014 and is currently collected at $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. As of December 31, 2014, OPCo's incurred deferred capacity costs balance of $422 million, including debt carrying costs, was recorded in regulatory assets on the balance sheet.

In 2013, the PUCO issued its Orders on Rehearing for the ESP which generally upheld its August 2012 order, including the implementation of the RSR. The PUCO clarified that a final reconciliation of revenues and expenses would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket related to the competitive bid process (CBP). In 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO's ESP order, including the RSR.

In November 2013, the PUCO issued an order approving OPCo's CBP with modifications. As ordered, in 2014, OPCo conducted multiple energy-only auctions for a total of 100% of the SSO load with delivery beginning April 2014 through May 2015. For delivery starting in June 2015, OPCo will conduct energy and capacity auctions for its entire SSO load. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings. Management believes that these intervenor concerns are without merit.

In January 2014, the PUCO denied all rehearing requests and agreed to issue a supplemental request for an independent auditor in the 2012 - 2013 FAC proceeding to separately examine the recovery of the fixed fuel costs, including OVEC. In March 2014, the PUCO approved OPCo's request to implement riders related to the unbundling of the FAC. In October 2014, the independent auditor, selected by the PUCO, filed its report for the period August 2012 through May 2015 with the PUCO. If the PUCO ultimately concludes that a portion of the fixed fuel costs are also recovered through OPCo's $188.88/MW day capacity charge, the independent auditor recommends a methodology for calculating a refund of a portion of certain fixed fuel costs. The retail share of these fixed fuel costs is approximately $90 million annually. A hearing related to this matter has not been scheduled. Management believes that no over-recovery of costs has occurred and intends to oppose the findings in the audit report.

If OPCo is ultimately not permitted to fully collect all components of its ESP rates, it could reduce future net income and cash flows and impact financial condition.

Proposed June 2015 – May 2018 ESP

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, including the Distribution Investment Rider (DIR), effective June 2015 through May 2018. The proposal included a return on common equity of 10.65% on capital costs for certain riders and estimates an average decrease in rates of 9% over the three-year term of the plan for customers who receive their RPM capacity and energy auction-based generation through OPCo. The proposal also included a purchased power agreement (PPA) rider that would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based purchase power agreement. The PPA would initially be based upon the OVEC contractual entitlement and could, upon further approval, be expanded to include other contracts involving other Ohio legacy generation assets. In May 2014, intervenors and the PUCO staff filed testimony that provided various recommendations including the rejection and/or modification of various riders, including the DIR and the proposed PPA. Hearings at the PUCO in the ESP case were held in June 2014.

In July 2014, OPCo submitted a separate application to continue the RSR established in the June 2012 - May 2015 ESP to collect the unrecovered portion of the deferred capacity costs at the rate of $4.00/MWh until the balance of the capacity deferrals has been collected. In December 2014, the PUCO staff and intervenors filed comments related to the RSR application. The PUCO staff recommended approval of the application. Intervenors objected to the application and recommended approval of a pending motion to dismiss.

In October 2014, OPCo filed a separate application with the PUCO to propose a new extended PPA for inclusion in the PPA rider, discussed above. The new PPA would include an additional 2,671 MW to be purchased from AGR over the life of the respective generating units.

If OPCo is ultimately not permitted to fully collect all components of its ESP rates, it could reduce future net income and cash flows and impact financial condition.

Significantly Excessive Earnings Test Filings

In January 2011, the PUCO issued an order on the 2009 SEET filing. The order gave consideration for a future commitment to invest $20 million to support the development of a large solar farm. In January 2013, the PUCO found there was not a need for the large solar farm. The PUCO noted that OPCo remains obligated to spend $20 million on this solar project or another project. In September 2013, a proposed second phase of OPCo's *gridSMART*® program was filed with the PUCO which included a proposed project to satisfy this PUCO directive. A decision from the PUCO is pending.

In March 2014, the PUCO approved a stipulation agreement between OPCo and the PUCO staff that there were no significantly excessive earnings in 2011 for CSPCo or OPCo. In May 2014 and December 2014, the PUCO approved stipulation agreements between OPCo and the PUCO staff that there were no significantly excessive earnings for OPCo in 2012 and 2013, respectively.

Management believes its financial statements adequately address the impact of 2014 SEET requirements.

Corporate Separation

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo's generation assets including the transfer of OPCo's generation assets and associated generation liabilities at net book value to AGR. In June 2013, the IEU filed an appeal with the Supreme Court of Ohio claiming the PUCO order approving the corporate separation was unlawful. A decision from the Supreme Court of Ohio is pending. In December 2013, corporate separation of OPCo's generation assets was completed. If any part of the PUCO order is overturned, it could reduce future net income and cash flows and impact financial condition.

Storm Damage Recovery Rider (SDRR)

In December 2012, OPCo submitted an application with the PUCO to establish initial SDRR rates to recover 2012 incremental storm distribution expenses. In April 2014, the PUCO approved a stipulation agreement to recover $55 million over a 12-month period. The agreement also provided that carrying charges using a long-term debt rate will be assessed from April 2013 until recovery begins, but no additional carrying charges will accrue during the actual recovery period. Compliance tariffs were filed with the PUCO and new rates were implemented in April 2014. In May 2014, the PUCO upheld the settlement agreement on rehearing.

2009 Fuel Adjustment Clause Audit

In January 2012, the PUCO issued an order in OPCo's 2009 FAC that the remaining $65 million in proceeds from a 2008 coal contract settlement agreement be applied against OPCo's under-recovered fuel balance. In April 2012, on rehearing, the PUCO ordered that the settlement credit only needed to reflect the Ohio retail jurisdictional share of the gain not already flowed through the FAC with carrying charges. As a result, OPCo recorded a $30 million net favorable adjustment on the statement of income in 2012. The January 2012 PUCO order also stated that a consultant should be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers.

In August 2012, intervenors filed an appeal with the Supreme Court of Ohio claiming the settlement credit ordered by the PUCO should have reflected the remaining gain not already flowed through the FAC, with carrying charges. In September 2014, the Supreme Court of Ohio upheld the PUCO order. A review of the coal reserve valuation by an outside consultant is still pending. If the PUCO ultimately determines that additional amounts should benefit ratepayers as a result of the consultant's review of the coal reserve valuation, it could reduce future net income and cash flows and impact financial condition.

2010 and 2011 Fuel Adjustment Clause Audits

The PUCO-selected outside consultant issued its 2010 and 2011 FAC audit reports which included a recommendation that the PUCO reexamine the carrying costs on the deferred FAC balance and determine whether the carrying costs on the balance should be net of accumulated income taxes with the use of a WACC. In May 2014, the PUCO issued an order that generally approved OPCo's 2010-2011 fuel costs and rejected the auditor recommendation to adjust the WACC carrying charges related to accumulated deferred income taxes. Additionally, the PUCO requested further review related to an affiliate barging agreement and the modification of certain fuel procurement processes and practices. Further, the order provided for the auditor to address any remaining concerns in the next audit report, as deemed necessary. In July 2014, the PUCO issued an order that denied all requests for rehearing.

2012 and 2013 Fuel Adjustment Clause Audits

In May 2014, the PUCO-selected outside consultant provided its final report related to its 2012 and 2013 FAC audit which included certain unfavorable recommendations related to the FAC recovery for 2012 and 2013. These recommendations are opposed by OPCo. In addition, the PUCO will consider the results of the final audit of the recovery of fixed fuel costs that was issued in October 2014. See the "June 2012 - May 2015 ESP Including Capacity Charge" section above. If the PUCO orders a reduction to the FAC deferral or a refund to customers, it could reduce future net income and cash flows and impact financial condition.

Ormet

Ormet, a large aluminum company, had a contract to purchase power from OPCo through 2018. In February 2013, Ormet filed for bankruptcy and subsequently shut down operations in October 2013. Based upon previous PUCO rulings providing rate assistance to Ormet, the PUCO is expected to permit OPCo to recover unpaid Ormet amounts through the Economic Development Rider (EDR), except where recovery from ratepayers is limited to $20 million related to previously deferred payments from Ormet's October and November 2012 power bills. In February 2014, a stipulation agreement between OPCo and Ormet was filed with the PUCO. The stipulation recommended approval of OPCo's right to fully recover approximately $49 million of foregone revenues through the EDR. Intervenor comments were also filed objecting to full recovery of these foregone revenues. In March 2014, the PUCO issued an order in OPCo's EDR filing allowing OPCo to include $39 million of Ormet-related foregone revenues in the EDR effective April 2014. The order stated that if the stipulation agreement between OPCo and Ormet is subsequently adopted by the PUCO, OPCo could file an application to modify the EDR rate for the remainder of the period requesting recovery of the remaining $10 million of Ormet deferrals which, as of December 31, 2014, is recorded in regulatory assets on the balance sheet. In April 2014, an intervenor filed testimony objecting to $5 million of the remaining foregone revenues. A hearing at the PUCO related to the stipulation agreement was held in May 2014.

In addition, in the 2009 - 2011 ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related revenues under a previous interim arrangement (effective from January 2009 through September 2009) and requested that the PUCO prevent OPCo from collecting Ormet-related revenues in the future. Through September 2009, the last month of the interim arrangement, OPCo had $64 million of deferred FAC costs related to the interim arrangement, excluding $2 million of unrecognized equity carrying costs. The PUCO did not take any action on this request. The intervenors raised this issue again in response to OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement.

To the extent amounts discussed above are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Ohio IGCC Plant

In 2005, OPCo filed an application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. As of December 31, 2014, OPCo has collected $24 million in pre-construction costs authorized in a 2006 PUCO order. Intervenors filed motions and comments with the PUCO requesting that OPCo refund all collected pre-construction costs to Ohio ratepayers with interest. In December 2014, a stipulation agreement between OPCo, the PUCO staff and intervenors was filed at the PUCO. The parties to the stipulation agreement proposed that OPCo will refund $13 million to its customers. In February 2015, the PUCO approved the stipulation agreement.

SWEPCo Rate Matters

2012 Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In October 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determined that the Turk Plant's Texas jurisdictional capital cost cap established in a previous Certificate of Convenience and Necessity case also limited SWEPCo's recovery of AFUDC in addition to limits on its recovery of cash construction costs. Additionally, the PUCT deferred consideration of the requested increase in depreciation expense related to the change in the 2016 retirement date of the Welsh Plant, Unit 2. As of December 31, 2014, the net book value of Welsh Plant, Unit 2 was $84 million, before cost of removal, including materials and supplies inventory and CWIP. See "Regulated Generating Units to be Retired Before or During 2016" section of Note 5.

Upon rehearing in January 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, in the fourth quarter of 2013, SWEPCo reversed $114 million of previously recorded regulatory disallowances. The resulting annual base rate increase is approximately $52 million. In March 2014, the PUCT issued an order related to the January 2014 PUCT ruling and in April 2014, this order became final. In May 2014, intervenors filed appeals of that order with the Texas District Court. In June 2014, SWEPCo intervened in those appeals and filed initial responses.

If certain parts of the PUCT order are overturned or if SWEPCo cannot ultimately recover its Texas jurisdictional share of the Turk Plant investment, including AFUDC, or its retirement-related costs and potential fuel or replacement power disallowances related to Welsh Plant, Unit 2, it could reduce future net income and cash flows and impact financial condition.

Texas Transmission Cost Recovery Factor Filing

In May 2014, SWEPCo filed an application with the PUCT to implement its transmission cost recovery factor (TCRF) requesting additional annual revenue of $15 million. The TCRF is designed to recover increases from the amounts included in SWEPCo's Texas retail base rates for transmission infrastructure improvement costs and wholesale transmission charges under a tariff approved by the FERC. SWEPCo's application included Turk Plant transmission-related costs. In November 2014, the PUCT issued an order approving a proposal for decision, issued by an Administrative Law Judge in October 2014, that recommended approval of SWEPCo's application with an increase in annual revenue of $14 million. In December 2014, the PUCT order became final and TCRF rates were implemented.

2012 Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share (approximately 29%) of the Turk Plant. In February 2013, a settlement was filed and approved by the LPSC. The settlement increased Louisiana total rates by approximately $2 million annually, effective March 2013, which consisted of an increase in base rates of approximately $85 million annually offset by a decrease in fuel and other rates of approximately $83 million annually. The March 2013 base rates are based on a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit. The rates are subject to refund based on the staff review of the cost of service and the prudency review of the Turk Plant. The settlement also provided that the LPSC review base rates in 2014 and 2015 and that SWEPCo recover non-fuel Turk Plant costs and a full weighted-average cost of capital return on the prudently incurred Turk Plant investment in jurisdictional rate base, effective January 2013. In December 2014, the LPSC approved a settlement agreement related to the staff review of the cost of service. The settlement agreement reduced the requested revenue increase by $3 million, primarily due to the timing of both the allowed recovery of certain existing regulatory assets and the establishment of a regulatory asset for certain previously expensed costs. If the LPSC orders refunds based upon the pending prudence review of the Turk Plant investment, it could reduce future net income and cash flows and impact financial condition.

2014 Louisiana Formula Rate Filing

In April 2014, SWEPCo filed its annual formula rate plan for test year 2013 with the LPSC. The filing included a $5 million annual increase, which was effective August 2014. SWEPCo also proposed to increase rates by an additional $15 million annually, effective January 2015, for a total annual increase of $20 million. This additional increase reflects the cost of incremental generation to be used to serve Louisiana customers in 2015 due to the expiration of a purchase power agreement attributable to Louisiana customers. In December 2014, the LPSC approved a partial settlement agreement that included the implementation of the $15 million annual increase in rates effective January 2015. These increases are subject to LPSC staff review and are subject to refund. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Welsh Plant, Units 1 and 3 - Environmental Projects

To comply with pending Federal EPA regulations, SWEPCo is currently constructing environmental control projects to meet mercury and air toxics standards for Welsh Plant, Units 1 and 3 at a cost of approximately $410 million, excluding AFUDC. Management currently estimates that the total environmental projects to be completed through 2020 for Welsh Plant, Units 1 and 3 will cost approximately $600 million, excluding AFUDC. As of December 31, 2014, SWEPCo has incurred costs of $164 million and has remaining contractual construction obligations of $108 million related to these projects. SWEPCo will seek recovery of these project costs from customers through filings at the state commissions and the FERC. As of December 31, 2014, the net book value of Welsh Plant, Units 1 and 3 was $388 million, before cost of removal, including materials and supplies inventory and CWIP. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

APCo and WPCo Rate Matters

Plant Transfer

APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a cost-of-service basis, to their respective customers. West Virginia generally allows for timely recovery of fuel costs through an expanded net energy cost which trues-up to actual expenses. In March 2014, APCo and WPCo filed a request with the WVPSC for approval to transfer at net book value to WPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity presently owned by AGR. In April 2014, APCo and WPCo filed testimony that supported their request and proposed a base rate surcharge of $113 million, to be offset by an equal reduction in the ENEC revenues, to be effective upon the transfer of the Mitchell Plant to WPCo until APCo's West Virginia base rates are updated. See the "2014 West Virginia Base Rate Case" below. In June 2014, the FERC issued an order approving a request by AGR and WPCo to transfer AGR’s one-half interest in the Mitchell Plant to WPCo.

In October 2014, a stipulation agreement between APCo, WPCo, the WVPSC staff and intervenors in the case was filed with the WVPSC. The stipulation agreement recommended approval for WPCo to acquire, at net book value, the one-half interest in the Mitchell Plant, excluding certain assets, and to pay AGR $20 million upon transfer, which WPCo will record as a regulatory asset, include in rate base and recover over the life of the plant. Additionally, the agreement stated that 82.5% of the costs associated with the acquired interest will be reflected in rates effective from the date of the transfer via a surcharge with an offset in ENEC revenues of $93 million. The remaining 17.5% of the costs associated with the acquired interest is to be included in rates by January 2020. The agreement also proposed that WPCo share the energy margins for 82.5% of the plant's output with ratepayers and that WPCo retain all of the energy margins from sales into the wholesale market on the remaining 17.5%, to offset fixed costs associated with this portion, until the remaining portion is included in rates. In December 2014, the WVPSC issued an order that approved the settlement agreement, subject to certain modifications related to 82.5% of the energy and capacity margin sharing. The WVPSC determined that the sharing mechanism that was proposed is reasonable and will be adopted provided the result of the sharing mechanism will be adjusted, if necessary, so that the sharing mechanism does not result in a net cost to ratepayers that exceeds the actual variable cost of generation. In January 2015, the transfer of the one-half interest in the Mitchell Plant to WPCo was completed.

2014 Virginia Biennial Base Rate Case

In March 2014, APCo filed a biennial generation and distribution base rate case with the Virginia SCC. In accordance with a Virginia statute, APCo did not request a change in base rates as its Virginia retail combined rate of return on common equity for 2012 and 2013 was within the statutory range of the approved return on common equity of 10.9%. The filing included a request to decrease generation depreciation rates, effective February 2015, primarily due to changes in the expected service lives of various generating units and the extended recovery through 2040 of the net book value of certain planned 2015 plant retirements. Additionally, the filing included a request to amortize $7 million annually for two years, beginning February 2015, related to IGCC and other deferred costs. APCo also requested approval to amortize $38 million related to an accumulated deferred Virginia state income tax (ADVSIT) liability over 20 years, beginning February 2015.

In November 2014, the Virginia SCC issued an order concluding that APCo's adjusted earned rate of return on common equity for 2012 and 2013, reflecting their ordered adjustments, was above the allowed threshold. The order included (a) a $6 million refund to customers for the years 2012 through 2013, (b) the write-off of $10 million of IGCC pre-construction costs, (c) approval to amortize a $38 million ADVSIT liability over 20 years, beginning February 2015 and (d) no change to generation depreciation rates with rates to be reviewed again in the next biennial rate case. The order also approved a new return on common equity of 9.7% effective for 2014 and 2015. Management believes its financial statements adequately address the impact of this order for 2014.

The Virginia SCC did not rule on a Virginia SCC staff recommendation to write-down certain costs, for ratemaking purposes, for the biennial period based on APCo's earnings within the statutory equity range. In January 2015, the Virginia SCC initiated a separate proceeding to address the proper treatment of APCo's authorized regulatory assets. As of December 31, 2014, APCo's authorized regulatory assets under review in the separate proceeding, based upon the Virginia SCC staff recommendation, are estimated to be $15 million. In February 2015, initial briefs related to this proceeding were filed by various parties. If any of these costs, or any additional costs that may be subject to review, are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Potential New Virginia Legislation Affecting Biennial Reviews

In February 2015, amendments to Virginia law governing the regulation of investor-owned electric utilities were approved by the Virginia General Assembly and have been sent to the Governor. If these amendments are enacted, APCo's existing generation and distribution base rates would freeze until after the Virginia SCC rules on APCo's next biennial review, which APCo would file in March 2020 for the 2018 and 2019 test years. These amendments would also preclude the Virginia SCC from performing biennial reviews of APCo's earnings for the years 2014 through 2017. Management continues to monitor this potential new legislation in Virginia.

2014 West Virginia Base Rate Case

In June 2014, APCo filed a request with the WVPSC to increase annual base rates by $181 million, based upon a 10.62% return on common equity, to be effective in the second quarter of 2015. The filing included a request to increase generation depreciation rates primarily due to the increase in plant investment and changes in the expected service lives of various generating units. The filing also requested recovery of $89 million over five years related to 2012 West Virginia storm costs, IGCC and other deferred costs. In addition to the base rate request, the filing also included a request to implement a rider of approximately $45 million annually to recover vegetation management costs, including a return on capital investment. In October 2014, the WVPSC approved APCo's motion to revise the procedural schedule which included a request to change the date of implementation of the new rates to May 2015. In December 2014 and January 2015, intervenors filed testimony which proposed total annual revenue increases ranging from $35 million to $59 million based upon returns on common equity ranging from 9% to 10% and regulatory asset disallowances ranging from $7 million to $9 million. Additionally, other intervenors proposed that the revenue requirement be based on a return on common equity of 8.7% and that $89 million of regulatory assets be disallowed. Intervenors also recommended a disallowance of approximately $44 million related to the December 2013 transfer of OPCo's two-thirds interest in the Amos Plant, Unit 3 to APCo. Hearings at the WVPSC were held in January 2015. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2013 Virginia Transmission Rate Adjustment Clause (Transmission RAC)

In December 2013, APCo filed with the Virginia SCC to increase its transmission RAC revenues by $50 million annually to be effective May 2014. In March 2014, the Virginia SCC issued an order approving a stipulation agreement between APCo and the Virginia SCC staff increasing the transmission RAC revenues by $49 million annually, subject to true-up, effective May 2014. Pursuant to the order, the Virginia SCC staff will audit APCo’s transmission RAC under-recoveries and report its findings and recommendations in testimony in APCo’s next transmission RAC proceeding in 2015.

PSO Rate Matters

2014 Oklahoma Base Rate Case

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. This revenue increase includes a proposed increase in depreciation rates of $29 million. In addition, the filing proposed recovery of advanced metering costs through a separate rider over a three-year deployment period requesting $7 million of revenues in year one, increasing to $28 million in year three. The filing also proposed expansion of an existing transmission rider currently recovered in base rates to include additional transmission-related costs that are expected to increase over the next several years.

In April and May 2014, testimony was filed by the OCC staff and intervenors with recommendations that included adjustments to annual base rates ranging from an increase of $16 million to a reduction of $22 million, primarily based upon the determination of depreciation rates and a return on common equity between 9.18% and 9.5%. Additionally, the recommendations did not support the advanced metering rider or the expansion of the transmission rider. In May 2014, PSO filed rebuttal testimony that included an updated annual base rate increase request of $42 million to reflect certain updated costs.

In June 2014, a non-unanimous stipulation agreement between PSO, the OCC staff and certain intervenors was filed with the OCC. The parties to the stipulation recommended no overall change to the transmission rider or to annual revenues, other than additional revenues through a separate rider related to advanced metering costs, and that the terms of the stipulation be effective November 2014. The advanced metering rider would provide $24 million of revenues over 14 months beginning in November 2014 and increase to $27 million in 2016. New depreciation rates are recommended for advanced metering investments and existing meters, also to be effective November 2014. Further, the stipulation recommends a return on common equity of 9.85% to be used only in the formula to calculate AFUDC, factoring of customer receivables and for riders with an equity component. Additionally, the stipulation recommends

recovery of regulatory assets for 2013 storms and regulatory case expenses. In July 2014, the Attorney General joined in the stipulation agreement. A hearing at the OCC was held in July 2014. In October 2014, the Administrative Law Judge (ALJ) recommended approval of the stipulation agreement and interim rates were implemented in November 2014, subject to refund. In November 2014, intervenors opposing the stipulation agreement filed exceptions to the ALJ's report and oral arguments were held at the OCC in December 2014. An order is anticipated in the first quarter of 2015. If the OCC were to disallow any portion of this settlement agreement, it could reduce future net income and cash flows and impact financial condition.

I&M Rate Matters

2011 Indiana Base Rate Case

In February 2013, the IURC issued an order that granted an $85 million annual increase in base rates based upon a return on common equity of 10.2% and adjusted the authorized annual increase in base rates to $92 million in March 2013. In April 2014, the Indiana Office of Utility Consumer Counselor (OUCC) filed an appeal to the Indiana Supreme Court related to the inclusion of a prepaid pension asset in rate base, which is approximately $7 million in annual revenues. In August 2014, the Indiana Supreme Court denied the appeal filed by the OUCC.

Cook Plant Life Cycle Management Project (LCM Project)

In 2012, I&M filed a petition with the IURC and the MPSC for approval of the LCM Project, which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its licensed life (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. As of December 31, 2014, I&M has incurred costs of $550 million related to the LCM Project, including AFUDC.

In July 2013, the IURC approved I&M's proposed project with the exception of an estimated $23 million related to certain items that might accommodate a future potential power uprate which the IURC stated I&M could seek recovery of in a subsequent base rate case. I&M will recover approved costs through an LCM rider which will be determined in semi-annual proceedings. The IURC authorized deferral accounting for costs incurred related to certain projects effective January 2012 to the extent such costs are not reflected in rates. In May 2014, the IURC issued a final order approving the LCM rider rates that were implemented in January 2014.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project and authorized deferral accounting for costs incurred related to the approved projects effective January 2013 until these costs are included in rates. 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 October 2014, the Michigan Court of Appeals issued an order that affirmed the MPSC decision in part, but reversed the portion of the MPSC decision related to certain costs. The order indicated that I&M could recover those costs in a future Michigan base case if they can show that the costs were reasonable and prudent.

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.

Tanners Creek Plant

I&M announced that it would retire Tanners Creek Plant by June 2015 to comply with proposed environmental regulations. I&M is currently recovering depreciation and a return on the net book value of the Tanners Creek Plant in base rates and plans to seek recovery of all of the plant's retirement related costs in its next Indiana and Michigan base rate cases.

In December 2013, I&M filed an application with the MPSC seeking approval of revised depreciation rates for Rockport Plant, Unit 1 and the Tanners Creek Plant due to the retirement of the Tanners Creek Plant in 2015. Upon the retirement of the Tanners Creek Plant, I&M proposed that, for purposes of determining its depreciation rates, the net book value of the Tanners Creek Plant be recovered over the remaining life of the Rockport Plant.

In September 2014, a settlement agreement was approved by the MPSC that included the authorization for I&M to implement revised depreciation rates for Rockport Plant, Unit 1, effective upon the retirement date of the Tanners Creek Plant. Upon implementation of the revised depreciation rates, I&M is authorized to reduce customer rates through a credit rider until the revised rates for Rockport Plant, Unit 1 are included in base rates.

In October 2014, I&M filed a similar application with the IURC seeking approval of revised depreciation rates for Rockport Plant, Unit 1 and the Tanners Creek Plant. Upon retirement of the Tanners Creek Plant, I&M proposed that, for purposes of determining its depreciation rates, the net book value of the Tanners Creek Plant be recovered over the remaining life of the Rockport Plant. The new depreciation rates would result in a decrease in I&M's Indiana jurisdictional electric depreciation expense which I&M proposed to reduce customer rates through a credit rider. In February 2015, the OUCC filed testimony that recommended approval of I&M's application. A hearing at the IURC is scheduled for March 2015.

As of December 31, 2014, the net book value of the Tanners Creek Plant was $340 million, before cost of removal, including material and supplies inventory and CWIP. See "Regulated Generating Units to be Retired Before or During 2016" section of Note 5. If I&M is ultimately not permitted to fully recover its net book value of the Tanners Creek Plant and its retirement-related costs, it could reduce future net income and cash flows and impact financial condition.

Transmission, Distribution and Storage System Improvement Charge (TDSIC)

In October 2014, I&M filed petitions with the IURC for approval of a TDSIC Rider and approval of I&M's seven-year TDSIC Plan, from 2015 through 2021, for eligible transmission, distribution and storage system improvements. The initial estimated cost of the capital improvements and associated operation and maintenance expenses included in the TDSIC Plan of $787 million, excluding AFUDC, will be updated annually. The TDSIC Plan included distribution investments specific to the Indiana jurisdiction. The TDSIC Rider will allow the periodic adjustment of I&M's rates to provide for timely recovery of 80% of approved TDSIC Plan costs. I&M will defer the remaining 20% of approved TDSIC Plan costs to be recovered in I&M's next general rate case. I&M is not seeking a rate adjustment in this proceeding but is seeking approval of a TDSIC Rider rate adjustment mechanism for subsequent proceedings. In January 2015, intervenors filed testimony that recommended denial of certain portions of the TDSIC Plan including recommended changes to the capital structure, recovery of requested operation and maintenance cost allocations and the rate design within the TDSIC Rider mechanism. A hearing at the IURC was held in February 2015. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

KPCo Rate Matters

Plant Transfer

In December 2012, KPCo filed a request with the KPSC for approval to transfer at net book value to KPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity. KPCo also requested that costs related to the Big Sandy Plant, Unit 2 FGD project be established as a regulatory asset. As of December 31, 2014, the net book value of Big Sandy Plant, Unit 2 was $253 million, before cost of removal, including materials and supplies inventory and CWIP. See "Regulated Generating Units to be Retired Before or During 2016" section of Note 5.

In October 2013, the KPSC issued an order approving a modified settlement agreement between KPCo, Kentucky Industrial Utility Customers, Inc. and the Sierra Club. The modified settlement approved the transfer of a one-half interest in the Mitchell Plant to KPCo at net book value on December 31, 2013 with the limitation that the net book value of the Mitchell Plant transfer not exceed the amount to be determined by a WVPSC order. In December 2014,

the WVPSC issued the Mitchell Plant transfer order with no disallowances. See the "Plant Transfer" disclosure above within the APCo and WPCo Rate Matters section. The modified settlement agreement approved by the KPSC also included the implementation of an Asset Transfer Rider to collect $44 million annually effective January 2014, subject to true-up, and allowed KPCo to retain any off-system sales margins above the $15.3 million annual level in base rates. Additionally, the settlement allows for KPCo to file a Certificate of Public Convenience and Necessity to convert Big Sandy Plant, Unit 1 to natural gas, provided the cost is approximately $60 million, and addressed potential greenhouse gas initiatives on the Mitchell Plant. The settlement also approved recovery, including a return, of coal-related retirement costs related to Big Sandy Plant over 25 years when base rates are set (no earlier than June 2015) in the next base rate case, but rejected KPCo's request to defer FGD project costs for Big Sandy Plant, Unit 2. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed.

In December 2013, the Attorney General filed an appeal with the Franklin County Circuit Court. In May 2014, KPCo's motion to dismiss the appeal was denied. In May 2014, KPCo filed motions for reconsideration and clarification with the Franklin County Circuit Court. In June 2014, the motion for reconsideration was denied but the motion to clarify was granted, thereby limiting the appeal to the issues of law presented in the Attorney General's appeal. If any part of the KPSC order is overturned, it could reduce future net income and cash flows and impact financial condition.

Kentucky Fuel Adjustment Clause Review

In August 2014, the KPSC issued an order initiating a review of KPCo's FAC from November 2013 through April 2014. In January 2015, the KPSC issued an order disallowing certain FAC costs during the period of January 2014 through May 2015 while KPCo owns and operates both Big Sandy Plant, Unit 2 and its one-half interest in the Mitchell Plant. Additionally, the KPSC directed KPCo to refund to customers $13 million of fuel costs, by the end of the second quarter of 2015, collected during the FAC review period of January 2014 through April 2014. As a result of this order, KPCo recorded a regulatory disallowance of $36 million in December 2014. In February 2015, KPCo filed an appeal of this order with the Franklin County Circuit Court.

2014 Kentucky Base Rate Case

In December 2014, KPCo filed a request with the KPSC for an increase in rates of $70 million, which consists of a $75 million increase in rider rates, offset by a $5 million decrease in annual base rates, to be effective July 2015. The net increase reflects KPCo's ownership interest in the Mitchell Plant, riders to recover the Big Sandy Plant retirement and operational costs and the inclusion of an environmental compliance plan related to the Mitchell Plant FGD. Additionally, the filing included a request to recover deferred storm costs. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

5. EFFECTS OF REGULATION

Regulated Generating Units to be Retired Before or During 2016

The following regulated generating units are probable of abandonment. Accordingly, CWIP and Plant in Service has been reclassified as Other Property, Plant and Equipment on the balance sheet as of December 31, 2014. The following table summarizes the plant investment and cost of removal, currently being recovered, for each generating unit as of December 31, 2014.

Plant Name and Unit	Company	Gross Investment	Accumulated Depreciation	Net Investment	Cost of Removal Regulatory Liability	Expected Retirement Date	Remaining Recovery Period
			(in millions)				
Tanners Creek Plant, Units 1-4	I&M	$ 711	$ 384	$ 327	$ 89	2015	16 years
Big Sandy Plant, Unit 2	KPCo	455	208	247	51	2015	26 years
Northeastern Station, Unit 4	PSO	182	91	91	11	2016	26 years
Welsh Plant, Unit 2	SWEPCo	175	96	79	20	2016	26 years
Total		$ 1,523	$ 779	$ 744	$ 171		

In accordance with accounting guidance for "Regulated Operations," APCo regulated generating units expected to be retired before or during 2016 are not considered probable of abandonment.

Regulatory Assets

Regulatory assets are comprised of the following items:

	December 31, 2014	December 31, 2013	Remaining Recovery Period
Current Regulatory Assets	(in millions)		
Under-recovered Fuel Costs - earns a return	$ 121	$ 61	1 year
Under-recovered Fuel Costs - does not earn a return	6	19	1 year
Total Current Regulatory Assets	$ 127	$ 80	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Storm Related Costs	$ 20	$ 22	
West Virginia Vegetation Management Program	20	—	
Ohio Economic Development Rider	—	14	
Other Regulatory Assets Pending Final Regulatory Approval	—	4	
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	100	161	
Carbon Capture and Storage Product Validation Facility	13	13	
IGCC Pre-Construction Costs	11	—	
Ormet Special Rate Recovery Mechanism	10	36	
Expanded Net Energy Charge - Coal Inventory	3	21	
Indiana Under-Recovered Capacity Costs	—	22	
Other Regulatory Assets Pending Final Regulatory Approval	49	37	
Total Regulatory Assets Pending Final Regulatory Approval	226	330	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Ohio Capacity Deferral	422	288	4 years
Ohio Fuel Adjustment Clause	378	445	4 years
Unamortized Loss on Reacquired Debt	66	81	29 years
Texas Meter Replacement Costs	59	77	13 years
Ohio Distribution Decoupling	35	31	2 years
Ohio Transmission Cost Recovery Rider	28	87	2 years
Storm Related Costs	13	17	4 years
Red Rock Generating Facility	10	10	42 years
RTO Formation/Integration Costs	9	12	5 years
Other Regulatory Assets Approved for Recovery	21	18	various
Regulatory Assets Currently Not Earning a Return			
Income Taxes, Net	1,268	1,390	53 years
Pension and OPEB Funded Status	1,273	1,157	13 years
Peak Demand Reduction/Energy Efficiency	62	44	2 years
Virginia Transmission Rate Adjustment Clause	53	47	2 years
Medicare Subsidy	46	51	10 years
Postemployment Benefits	39	40	4 years
Cook Plant Nuclear Refueling Outage Levelization	38	58	2 years
Storm Related Costs	26	18	4 years
Indiana Under-Recovered Capacity Costs	25	—	1 year
United Mine Workers of America Pension Withdrawal	25	27	11 years
Under-Recovery of PJM Expense	22	—	2 years
Under-Recovered *gridSMART*® Costs	16	8	2 years
Under-Recovery of Transmission Cost Recovery Factor	15	20	1 year
Under-Recovered Distribution Investment Rider	10	9	2 years
Unrealized Loss on Forward Commitments	10	—	3 years
Litigation Settlement	9	10	11 years
Deferred Restructuring Costs	8	11	4 years
Vegetation Management	5	14	1 year
Virginia Environmental Rate Adjustment Clause	3	27	1 year
Other Regulatory Assets Approved for Recovery	44	49	various
Total Regulatory Assets Approved for Recovery	4,038	4,046	
Total Noncurrent Regulatory Assets	$ 4,264	$ 4,376	

Regulatory Liabilities

Regulatory liabilities are comprised of the following items:

	December 31, 2014	December 31, 2013	Remaining Refund Period
Current Regulatory Liabilities	(in millions)		
Over-recovered Fuel Costs - pays a return	$ —	$ 9	
Over-recovered Fuel Costs - does not pay a return	55	110	1 year
Total Current Regulatory Liabilities	$ 55	$ 119	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	$ —	$ 5	
Regulatory Liabilities Currently Not Paying a Return			
Provision for Regulatory Loss	35	—	
Other Regulatory Liabilities Pending Final Regulatory Determination	17	3	
Total Regulatory Liabilities Pending Final Regulatory Determination	52	8	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	2,660	2,589	(a)
Louisiana Refundable Construction Financing Costs	58	78	4 years
Advanced Metering Infrastructure Surcharge	44	68	6 years
Deferred Investment Tax Credits	26	29	46 years
Excess Earnings	11	12	39 years
Other Regulatory Liabilities Approved for Payment	4	1	various
Regulatory Liabilities Currently Not Paying a Return			
Excess Asset Retirement Obligations for Nuclear Decommissioning Liability	695	597	(b)
Deferred Investment Tax Credits	112	121	50 years
Unrealized Gain on Forward Commitments	92	35	18 years
Over-Recovery of Transition Charges	47	40	13 years
Spent Nuclear Fuel Liability	44	43	(b)
Indiana Off-system Sales Margin Sharing	19	—	2 years
Peak Demand Reduction/Energy Efficiency	3	18	2 years
Deferred State Income Tax Coal Credits	—	28	
Over-Recovery of PJM Expense	—	14	
Other Regulatory Liabilities Approved for Payment	25	13	various
Total Regulatory Liabilities Approved for Payment	3,840	3,686	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 3,892	$ 3,694	

(a) Relieved as removal costs are incurred.
(b) Relieved when plant is decommissioned.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on our financial statements.

COMMITMENTS

Construction and Commitments

The AEP System has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, we contractually commit to third-party construction vendors for certain material purchases and other construction services. The subsidiaries purchase fuel, materials, supplies, services and property, plant and equipment under contract as part of their normal course of business. Certain supply contracts contain penalty provisions for early termination.

The following table summarizes our actual contractual commitments as of December 31, 2014:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 2,240	$ 2,735	$ 1,825	$ 2,104	$ 8,904
Energy and Capacity Purchase Contracts	363	405	426	2,087	3,281
Construction Contracts for Capital Assets (b)	191	—	—	—	191
Total	$ 2,794	$ 3,140	$ 2,251	$ 4,191	$ 12,376

(a) Represents contractual commitments to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.

(b) Represents only capital assets for which we have signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

GUARANTEES

We record liabilities for guarantees in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit

We enter into standby letters of credit with third parties. As Parent, we issue all of these letters of credit in our ordinary course of business on behalf of our subsidiaries. These letters of credit cover items such as natural gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

We have two revolving credit facilities totaling $3.5 billion, under which we may issue up to $1.2 billion as letters of credit. As of December 31, 2014, the maximum future payments for letters of credit issued under the revolving credit facilities were $63 million with maturities ranging from February 2015 to March 2016.

In January 2014, we issued letters of credit under an $85 million uncommitted facility. In October 2014, the uncommitted facility was renewed through October 2015 and increased to $100 million. As of December 31, 2014, the maximum future payments for letters of credit issued under the revolving credit facilities were $81 million with a maturity of July 2015. An uncommitted facility gives the issuer of the facility the right to accept or decline each request we make under the facility.

We have $477 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $483 million. The letters of credit have maturities ranging from March 2015 to July 2017. In February 2015, $78 million of bilateral letters of credit maturing in March 2015 were extended to March 2017.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $115 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study completed in 2010, we estimate the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately $58 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of December 31, 2014, SWEPCo has collected approximately $64 million through a rider for final mine closure and reclamation costs, of which $16 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $48 million is recorded in Asset Retirement Obligations on the balance sheet.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs to customers through its fuel clause.

Indemnifications and Other Guarantees

Contracts

We enter into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. As of December 31, 2014, there were no material liabilities recorded for any indemnifications.

Lease Obligations

We lease certain equipment under master lease agreements. See “Master Lease Agreements” and “Railcar Lease” sections of Note 13 for disclosure of lease residual value guarantees.

ENVIRONMENTAL CONTINGENCIES

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, our generation plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. We currently incur costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. As of December 31, 2014, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for four sites for which alleged liability is unresolved. There are nine additional sites for which our subsidiaries have received information requests which could lead to PRP designation. Our subsidiaries have also been named potentially liable at three sites under state law including the I&M site discussed in the next paragraph. In those instances where we have been named a PRP or defendant, our disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ. In September 2014, I&M recorded an accrual for remediation at certain additional sites in Michigan. As of December 31, 2014, I&M's accrual for all of these sites is approximately $15 million. As the remediation work is completed, I&M's cost may change as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation. We cannot predict the amount of additional cost, if any.

We evaluate the potential liability for each Superfund site separately, but several general statements can be made about our potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. At present, our estimates do not anticipate material cleanup costs for any of our identified Superfund sites, except the I&M sites discussed above.

NUCLEAR CONTINGENCIES

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission (NRC). We have a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generating units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the liability could be substantial.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The most recent decommissioning cost study was performed in 2012. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste ranges from $1.3 billion to $1.7 billion in 2012 nondiscounted dollars. The wide range in estimated costs is caused by variables in assumptions. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were $9 million, $10 million and $14 million for the years ended December 31, 2014, 2013 and 2012, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2014 and 2013, the total decommissioning trust fund balance was $1.8 billion and $1.6 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including interest, unrealized gains and losses and expenses of the trust funds) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future net income and cash flows would be reduced and financial condition could be impacted if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

SNF Disposal

The federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWh for fuel consumed after April 6, 1983 at the Cook Plant was being collected from customers and remitted to the U.S. Treasury. This fee was terminated in May 2014. As of December 31, 2014 and 2013, fees and related interest of $266 million and $265 million, respectively, for fuel consumed prior to April 7, 1983 have been recorded as Long-term Debt and funds collected from customers along with related earnings totaling $309 million and $309 million, respectively, to pay the fee are recorded as part of Spent Nuclear Fuel and Decommissioning Trusts. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

In 2011, I&M signed a settlement agreement with the federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government's delays in accepting SNF for permanent storage. Under the settlement agreement, I&M received $22 million, $31 million and $20 million in 2014, 2013 and 2012, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2016. The proceeds reduced costs for dry cask storage. As of December 31, 2014, I&M has deferred $13 million in Prepayments and Other Current Assets and $2 million in Deferred Charges and Other Noncurrent Assets on the balance sheet of dry cask storage and related operation and maintenance costs for recovery under this agreement.

See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Nuclear Incident Liability

I&M carries insurance coverage for a nuclear incident at the Cook Plant for property damage, decommissioning and decontamination in the amount of $2.8 billion. Insurance coverage for a nonnuclear incident at the Cook Plant is $1.7 billion. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes industry mutual insurers for the placement of this insurance coverage. Participation in this mutual insurance requires a contingent financial obligation of up to $44 million for I&M which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public liability arising from a nuclear incident at $13.6 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $375 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $121 million on each licensed reactor in the U.S. payable in annual installments of $19 million. As a result, I&M could be assessed $242 million per nuclear incident payable in annual installments of $38 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is initially covered for the first $375 million through commercially available insurance. The next level of liability coverage of up to $13.2 billion would be covered by claims made under the Price-Anderson Act. If the liability were in excess of amounts recoverable from insurance and retrospective claim payments made under the Price-Anderson Act, I&M would seek to recover those amounts from customers through rate increases. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

We maintain insurance coverage normal and customary for an integrated electric utility, subject to various deductibles. We also maintain property and casualty insurance that may cover certain physical damage or third-party injuries caused by cyber security incidents. Our insurance includes coverage for all risks of physical loss or damage to our nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. Our insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of retentions absorbed by us. Coverage is generally provided by a combination of our protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

See "Nuclear Contingencies" section of this footnote for a discussion of nuclear exposures and related insurance.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to a cyber security incident or damage to the Cook Plant and costs of replacement power in the event of an incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could reduce future net income and cash flows and impact financial condition.

Rockport Plant Litigation

In July 2013, the Wilmington Trust Company filed a complaint in U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiff further alleges that the defendants' actions constitute breach of the lease and participation agreement. The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff. The New York court has granted our motion to transfer this case to the U.S. District Court for the Southern District of Ohio. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M. In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiffs' claims. Several claims remain, including the claim for breach of the participation agreement and a claim alleging breach of an implied covenant of good faith and fair dealing. We will continue to defend against the remaining claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against numerous energy companies, including AEP, alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were also filed in California and in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP (or a subsidiary) is among the companies named as defendants in some of these cases. We settled, received summary judgment or were dismissed from all of these cases. The plaintiffs appealed the Nevada federal district court's dismissal of several cases involving AEP companies to the U.S. Court of Appeals for the Ninth Circuit. In April 2013, the appellate court reversed in part, and affirmed in part, the district court's orders in these cases. The appellate court reversed the district court's holding that the state antitrust claims were preempted by the Natural Gas Act and the order dismissing AEP from two of the cases on personal jurisdiction grounds and affirmed the decision denying leave to the plaintiffs to amend their complaints in two of the cases. Defendants in these cases, including AEP, previously filed a petition seeking further review with the U.S. Supreme Court on the preemption issue. In June 2014, AEP filed a petition with the U.S. Supreme Court seeking review of the personal jurisdiction issue. In July 2014,

the U.S. Supreme Court granted the defendants' previously filed petition for further review with the U.S. Supreme Court on the preemption issue. Oral argument occurred in January 2015. We will continue to defend the cases. We believe the provision we have is adequate. We are unable to determine the amount of potential additional losses that are reasonably possible of occurring.

Wage and Hours Lawsuit

In August 2013, PSO received an amended complaint filed in the U.S. District Court for the Northern District of Oklahoma by 36 current and former line and warehouse employees alleging that they have been denied overtime pay in violation of the Fair Labor Standards Act. Plaintiffs claim that they are entitled to overtime pay for "on call" time. They allege that restrictions placed on them during on call hours are burdensome enough that they are entitled to compensation for these hours as hours worked. Plaintiffs also filed a motion to conditionally certify this action as a class action, claiming there are an additional 70 individuals similarly situated to plaintiffs. Plaintiffs seek damages in the amount of unpaid overtime over a three-year period and liquidated damages in the same amount.

In March 2014, the federal court granted plaintiffs' motion to conditionally certify the action as a class action. Notice was given to all potential class members and an additional 44 individuals opted in to the class, bringing the plaintiff class to 80 current and former employees. We will continue to defend the case. We are unable to determine a range of potential losses that are reasonably possible of occurring.

National Do Not Call Registry Lawsuit

In May 2014, AEP Energy was served with a complaint filed in the U.S. District Court for the Northern District of Illinois, alleging violations of the Telephone Consumer Protection Act (TCPA). The plaintiff alleges that he received telemarketing calls on behalf of AEP Energy despite having registered his telephone number on the National Do Not Call Registry. Plaintiff seeks to represent a class of persons who allegedly received such calls. Plaintiff seeks statutory damages under the TCPA on behalf of himself and the alleged class as well as injunctive relief. As a result of a mediation held in October 2014, the parties reached an agreement in principle, subject to final documentation and preliminary and final court approval. We will continue to defend the case. We believe the provision we have is adequate. We are unable to determine the amount of potential additional losses that are reasonably possible of occurring.

Gavin Landfill Litigation

In August 2014, a complaint was filed in the Mason County, West Virginia Circuit Court against AEP, AEPSC, OPCo and an individual supervisor alleging wrongful death and personal injury/illness claims arising out of purported exposure to coal combustion by-product waste at the Gavin Plant landfill. The lawsuit was filed on behalf of 77 plaintiffs, consisting of 39 current and former contractors of the landfill and 38 family members of those contractors. Eleven of the family members are pursuing personal injury/illness claims and the remainder are pursuing loss of consortium claims. The plaintiffs seek compensatory and punitive damages, as well as medical monitoring. In September 2014, we filed a motion to dismiss the complaint, contending the case should be filed in Ohio. That motion is pending. We will continue to defend against the claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

7. ACQUISITION AND IMPAIRMENTS

ACQUISITION

2012

BlueStar Energy (Generation & Marketing segment)

In March 2012, we completed the acquisition of BlueStar Energy Holdings, Inc. (BlueStar) and its independent retail electric supplier BlueStar Energy Solutions for $70 million. This transaction also included goodwill of $15 million, intangible assets associated with sales contracts and customer accounts of $58 million and liabilities associated with supply contracts of $25 million. BlueStar has been in operation since 2002. Beginning in June 2012, BlueStar began doing business as AEP Energy. AEP Energy provides electric supply for retail customers in Ohio, Illinois and other deregulated electricity markets and also provides energy solutions throughout the United States, including demand response and energy efficiency services.

IMPAIRMENTS

2013

Amos Plant, Unit 3 (Vertically Integrated Utilities segment)

In July 2013, the Virginia SCC approved the transfer of a two-thirds interest in the Amos Plant, Unit 3 to APCo but, for rate purposes, reduced the proposed transfer price by $83 million pretax. The Virginia jurisdictional share of the reduced price is approximately $39 million. In December 2013, the WVPSC issued an order that approved the transfer of a two-thirds interest in the Amos Plant, Unit 3 to APCo but deferred a final decision related to the $83 million pretax reduction in transfer price until APCo's next base rate case. The West Virginia and FERC jurisdictional share of the potential reduced transfer price is approximately $44 million. Upon evaluation, management believes the West Virginia jurisdictional share is probable of recovery. As a result of the Virginia order, in the fourth quarter of 2013, we recorded a pretax impairment of $39 million in Asset Impairments and Other Related Charges on the statement of income.

Big Sandy Plant, Unit 2 FGD Project (Vertically Integrated Utilities segment)

In the third quarter of 2013, KPCo recorded a pretax write-off of $33 million in Asset Impairments and Other Related Charges on the statement of income primarily related to the Big Sandy Plant, Unit 2 FGD project as disallowed by the KPSC.

Muskingum River Plant, Unit 5 (Generation & Marketing segment)

In May 2013, the U.S. District Court for the Southern District of Ohio approved a modification to the consent decree, which was initially entered into in 2007, requiring certain types of pollution control equipment to be installed at certain AEP plants, including the 600 MW Muskingum River Plant, Unit 5 (MR5) coal-fired generation plant. Under the modification to the consent decree, we have the option to cease burning coal and retire MR5 in 2015 or to cease burning coal in 2015 and complete a natural gas refueling project no later than June 2017. In the second quarter of 2013, based on the approval of the modified consent decree and changes in other market factors, we re-evaluated potential courses of action with respect to the planned operation of MR5 and concluded that completion of a refueling project, which would have extended the useful life of MR5, is remote. As a result, management completed an impairment analysis and concluded that MR5 was impaired. Under a market-based value approach, using level 3 unobservable inputs, management determined that the fair value of this generating unit was zero based on the lack of installed environmental control equipment and the nature and condition of this generating unit. In the second quarter of 2013, we recorded a pretax impairment of $154 million in Asset Impairments and Other Related Charges on the statement of income which includes a $6 million pretax impairment of related material and supplies inventory. Management expects to retire the plant in 2015.

2012

Beckjord Plant, Unit 6, Conesville Plant, Unit 3, Kammer Plant, Units 1-3, Muskingum River Plant, Units 1-4, Sporn Plant, Units 2 and 4 and Picway Plant, Unit 5 (Generation & Marketing segment)

In October 2012, we filed applications with the FERC proposing to terminate the Interconnection Agreement and seeking to complete the corporate separation of OPCo's generation assets. Based on the intention to terminate the Interconnection Agreement and the FERC filing, we performed an evaluation of the recoverability of generation assets. As a result, in November 2012, we, using generating unit specific estimated future cash flows, concluded that we had a material impairment of certain Ohio generation assets. Under a market-based value approach, using level 3 unobservable inputs, we determined that the fair value of these generating units was zero based on the lack of installed environmental control equipment and the nature and condition of these generating units. In the fourth quarter of 2012, we recorded a pretax impairment of $287 million in Asset Impairments and Other Related Charges on the statement of income related to Beckjord Plant, Unit 6, Conesville Plant, Unit 3, Kammer Plant, Units 1-3, Muskingum River Plant, Units 1-4, Sporn Plant, Units 2 and 4 and Picway Plant, Unit 5 generating units which includes $13 million of related material and supplies inventory.

Turk Plant (Vertically Integrated Utilities segment)

In 2012, SWEPCo recorded a pretax write-off of $13 million in Asset Impairments and Other Related Charges on the statement of income related to unrecoverable construction costs subject to the Texas capital costs cap portion of the Turk Plant.

8. BENEFIT PLANS

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1.

We sponsor a qualified pension plan and two unfunded nonqualified pension plans. Substantially all of our employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. We sponsor OPEB plans to provide health and life insurance benefits for retired employees.

We recognize the funded status associated with our defined benefit pension and OPEB plans in the balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. We record a regulatory asset instead of other comprehensive income for qualifying benefit costs of our regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions as of December 31 of each year used in the measurement of our benefit obligations are shown in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2014**	**2013**	**2014**	**2013**
Discount Rate	4.00%	4.70%	4.00%	4.70%
Rate of Compensation Increase	4.80% (a)	4.85% (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

NA Not applicable.

We use a duration-based method to determine the discount rate for our plans. A hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2014, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 12% per year, with an average increase of 4.8%.

We updated our mortality assumption for the December 31, 2014 benefit obligation measurements based on mortality tables issued by the Society of Actuaries in October 2014. These updates increased our benefit obligations by approximately $128 million for the pension plans and $8 million for the OPEB plans.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1 of each year used in the measurement of our benefit costs are shown in the following table:

	Pension Plans			Other Postretirement Benefit Plans		
	2014	2013	2012	2014	2013	2012
Discount Rate	4.70%	3.95%	4.55%	4.70%	3.95%	4.75%
Expected Return on Plan Assets	6.00%	6.50%	7.25%	6.75%	7.00%	7.25%
Rate of Compensation Increase	4.85%	4.95%	4.85%	NA	NA	NA

NA Not applicable.

The expected return on plan assets was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation and current prospects for economic growth.

The health care trend rate assumptions as of January 1 of each year used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	2014	2013
Initial	6.50%	6.75%
Ultimate	5.00%	5.00%
Year Ultimate Reached	2020	2020

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 4	$ (3)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	77	(60)

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. We monitor the plans to control security diversification and ensure compliance with our investment policy. As of December 31, 2014, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status as of December 31, 2014 and 2013

The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets and funded status as of December 31. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans		Other Postretirement Benefit Plans	
	2014	2013	2014	2013
Change in Benefit Obligation		(in millions)		
Benefit Obligation as of January 1,	$ 4,841	$ 5,205	$ 1,456	$ 1,849
Service Cost	72	69	14	23
Interest Cost	221	203	67	71
Actuarial (Gain) Loss	387	(305)	(14)	(395)
Benefit Payments	(296)	(331)	(134)	(140)
Participant Contributions	—	—	42	39
Medicare Subsidy	—	—	8	9
Benefit Obligation as of December 31,	$ 5,225	$ 4,841	$ 1,439	$ 1,456
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 4,711	$ 4,696	$ 1,699	$ 1,568
Actual Gain on Plan Assets	474	340	83	208
Company Contributions	79	6	4	24
Participant Contributions	—	—	42	39
Benefit Payments	(296)	(331)	(134)	(140)
Fair Value of Plan Assets as of December 31,	$ 4,968	$ 4,711	$ 1,694	$ 1,699
Funded (Underfunded) Status as of December 31,	$ (257)	$ (130)	$ 255	$ 243

Amounts Recognized on the Balance Sheets as of December 31, 2014 and 2013

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2014	2013	2014	2013
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 337	$ 264
Other Current Liabilities – Accrued Short-term Benefit Liability	(6)	(7)	(4)	(4)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(251)	(123)	(78)	(17)
Funded (Underfunded) Status	$ (257)	$ (130)	$ 255	$ 243

Amounts Included in AOCI and Regulatory Assets as of December 31, 2014 and 2013

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2014	2013	2014	2013
Components	(in millions)			
Net Actuarial Loss	$ 1,612	$ 1,561	$ 420	$ 428
Prior Service Cost (Credit)	5	8	(624)	(693)
Recorded as				
Regulatory Assets	$ 1,418	$ 1,343	$ (149)	$ (191)
Deferred Income Taxes	70	79	(19)	(26)
Net of Tax AOCI	129	147	(36)	(48)

Components of the change in amounts included in AOCI and Regulatory Assets during the years ended December 31, 2014 and 2013 are as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2014	2013	2014	2013
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 175	$ (367)	$ 14	$ (496)
Amortization of Actuarial Loss	(124)	(183)	(22)	(65)
Amortization of Prior Service Credit (Cost)	(3)	(3)	69	69
Change for the Year	$ 48	$ (553)	$ 61	$ (492)

Pension and Other Postretirement Benefits Plans' Assets

The following table presents the classification of pension plan assets within the fair value hierarchy as of December 31, 2014:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 589	$ —	$ —	$ —	$ 589	11.9 %
International	502	—	—	—	502	10.1 %
Options	—	14	—	—	14	0.3 %
Real Estate Investment Trusts	54	—	—	—	54	1.1 %
Common Collective Trust – Global	—	377	—	—	377	7.6 %
Common Collective Trust – International	—	19	—	—	19	0.4 %
Subtotal – Equities	1,145	410	—	—	1,555	31.4 %
Fixed Income:						
Common Collective Trust – Debt	—	30	—	—	30	0.6 %
United States Government and Agency Securities	—	450	—	—	450	9.0 %
Corporate Debt	—	1,799	—	—	1,799	36.2 %
Foreign Debt	—	401	—	—	401	8.1 %
State and Local Government	—	15	—	—	15	0.3 %
Other – Asset Backed	—	29	—	—	29	0.6 %
Subtotal – Fixed Income	—	2,724	—	—	2,724	54.8 %
Infrastructure	—	—	13	—	13	0.3 %
Real Estate	—	—	236	—	236	4.7 %
Alternative Investments	—	—	379	—	379	7.6 %
Securities Lending	—	220	—	—	220	4.4 %
Securities Lending Collateral (a)	—	—	—	(222)	(222)	(4.5)%
Cash and Cash Equivalents	—	53	—	—	53	1.1 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	10	10	0.2 %
Total	$ 1,145	$ 3,407	$ 628	$ (212)	$ 4,968	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay collateral received as part of the Securities Lending Program.

(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table sets forth a reconciliation of changes in the fair value of assets classified as Level 3 in the fair value hierarchy for the pension assets:

	Infrastructure	Real Estate	Alternative Investments	Total Level 3
		(in millions)		
Balance as of January 1, 2014	$ —	$ 238	$ 330	$ 568
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	—	6	32	38
Relating to Assets Sold During the Period	—	19	16	35
Purchases and Sales	13	(27)	1	(13)
Transfers into Level 3	—	—	—	—
Transfers out of Level 3	—	—	—	—
Balance as of December 31, 2014	$ 13	$ 236	$ 379	$ 628

The following table presents the classification of OPEB plan assets within the fair value hierarchy as of December 31, 2014:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 466	$ —	$ —	$ —	$ 466	27.5%
International	567	—	—	—	567	33.5%
Options	—	16	—	—	16	1.0%
Common Collective Trust – Global	—	30	—	—	30	1.8%
Subtotal – Equities	1,033	46	—	—	1,079	63.8%
Fixed Income:						
Common Collective Trust – Debt	—	104	—	—	104	6.1%
United States Government and Agency Securities	—	71	—	—	71	4.2%
Corporate Debt	—	125	—	—	125	7.4%
Foreign Debt	—	21	—	—	21	1.3%
State and Local Government	—	6	—	—	6	0.3%
Other – Asset Backed	—	5	—	—	5	0.3%
Subtotal – Fixed Income	—	332	—	—	332	19.6%
Trust Owned Life Insurance:						
International Equities	—	10	—	—	10	0.6%
United States Bonds	—	212	—	—	212	12.5%
Subtotal – Trust Owned Life Insurance	—	222	—	—	222	13.1%
Cash and Cash Equivalents	47	10	—	—	57	3.3%
Other – Pending Transactions and Accrued Income (a)	—	—	—	4	4	0.2%
Total	$ 1,080	$ 610	$ —	$ 4	$ 1,694	100.0%

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of pension plan assets within the fair value hierarchy as of December 31, 2013:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 1,092	$ —	$ —	$ —	$ 1,092	23.2 %
International	514	—	—	—	514	10.9 %
Real Estate Investment Trusts	58	—	—	—	58	1.2 %
Common Collective Trust – International	—	10	—	—	10	0.2 %
Subtotal – Equities	1,664	10	—	—	1,674	35.5 %
Fixed Income:						
Common Collective Trust – Debt	—	26	—	—	26	0.5 %
United States Government and Agency Securities	—	387	—	—	387	8.2 %
Corporate Debt	—	1,600	—	—	1,600	34.0 %
Foreign Debt	—	344	—	—	344	7.3 %
State and Local Government	—	28	—	—	28	0.6 %
Other – Asset Backed	—	33	—	—	33	0.7 %
Subtotal – Fixed Income	—	2,418	—	—	2,418	51.3 %
Real Estate	—	—	238	—	238	5.0 %
Alternative Investments	—	—	330	—	330	7.0 %
Securities Lending	—	35	—	—	35	0.8 %
Securities Lending Collateral (a)	—	—	—	(45)	(45)	(0.9)%
Cash and Cash Equivalents	—	48	—	—	48	1.0 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	13	13	0.3 %
Total	$ 1,664	$ 2,511	$ 568	$ (32)	$ 4,711	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay collateral received as part of the Securities Lending Program.

(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table sets forth a reconciliation of changes in the fair value of assets classified as Level 3 in the fair value hierarchy for the pension assets:

	Real Estate	Alternative Investments	Total Level 3
		(in millions)	
Balance as of January 1, 2013	$ 220	$ 195	$ 415
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	26	15	41
Relating to Assets Sold During the Period	—	15	15
Purchases and Sales	(8)	105	97
Transfers into Level 3	—	—	—
Transfers out of Level 3	—	—	—
Balance as of December 31, 2013	$ 238	$ 330	$ 568

The following table presents the classification of OPEB plan assets within the fair value hierarchy as of December 31, 2013:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 473	$ —	$ —	$ —	$ 473	27.9%
International	616	—	—	—	616	36.2%
Common Collective Trust – Global	—	15	—	—	15	0.9%
Subtotal – Equities	1,089	15	—	—	1,104	65.0%
Fixed Income:						
Common Collective Trust – Debt	—	88	—	—	88	5.2%
United States Government and Agency Securities	—	56	—	—	56	3.3%
Corporate Debt	—	110	—	—	110	6.5%
Foreign Debt	—	22	—	—	22	1.2%
State and Local Government	—	5	—	—	5	0.3%
Other – Asset Backed	—	8	—	—	8	0.5%
Subtotal – Fixed Income	—	289	—	—	289	17.0%
Trust Owned Life Insurance:						
International Equities	—	13	—	—	13	0.8%
United States Bonds	—	211	—	—	211	12.4%
Subtotal – Trust Owned Life Insurance	—	224	—	—	224	13.2%
Cash and Cash Equivalents	68	9	—	—	77	4.5%
Other – Pending Transactions and Accrued Income (a)	—	—	—	5	5	0.3%
Total	$ 1,157	$ 537	$ —	$ 5	$ 1,699	100.0%

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

Determination of Pension Expense

We base our determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return.

The accumulated benefit obligation for the pension plans is as follows:

Accumulated Benefit Obligation	December 31, 2014	2013
	(in millions)	
Qualified Pension Plan	$ 4,982	$ 4,638
Nonqualified Pension Plans	76	77
Total	$ 5,058	$ 4,715

For our underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets of these plans as of December 31, 2014 and 2013 were as follows:

	Underfunded Pension Plans	
	December 31,	
	2014	2013
	(in millions)	
Projected Benefit Obligation	$ 5,225	$ 4,841
Accumulated Benefit Obligation	$ 5,058	$ 4,715
Fair Value of Plan Assets	4,968	4,711
Underfunded Accumulated Benefit Obligation	$ (90)	$ (4)

Estimated Future Benefit Payments and Contributions

We expect contributions and payments for the pension plans of $93 million and the OPEB plans of $6 million during 2015. For the pension plans, this amount includes the payment of unfunded nonqualified benefits plus contributions to the qualified trust fund of at least the minimum amount required by the Employee Retirement Income Security Act. For the qualified pension plan, we may also make additional discretionary contributions to maintain the funded status of the plan. For the OPEB plans, expected payments include the payment of unfunded benefits.

The table below reflects the total benefits expected to be paid from the plan or from our assets. The payments include the participants' contributions to the plan for their share of the cost. Effective for employees hired after December 2013, we will not provide retiree medical coverage. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for pension benefits and OPEB are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2015	$ 315	$ 129	$ —
2016	323	129	—
2017	334	130	—
2018	341	132	—
2019	350	132	—
Years 2020 to 2024, in Total	1,822	688	2

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost (credit) for the plans for the years ended December 31, 2014, 2013 and 2012:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2014	2013	2012	2014	2013	2012
	(in millions)					
Service Cost	$ 72	$ 69	$ 76	$ 14	$ 23	$ 47
Interest Cost	221	203	223	67	71	103
Expected Return on Plan Assets	(262)	(278)	(319)	(111)	(107)	(101)
Amortization of Transition Obligation	—	—	—	—	—	1
Amortization of Prior Service Cost (Credit)	3	3	(1)	(69)	(69)	(18)
Amortization of Net Actuarial Loss	124	183	155	22	65	57
Net Periodic Benefit Cost (Credit)	158	180	134	(77)	(17)	89
Capitalized Portion	(52)	(56)	(42)	25	5	(28)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 106	$ 124	$ 92	$ (52)	$ (12)	$ 61

Estimated amounts expected to be amortized to net periodic benefit costs (credits) and the impact on the balance sheet during 2015 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 108	$ 17
Prior Service Cost (Credit)	2	(69)
Total Estimated 2015 Amortization	$ 110	$ (52)
Expected to be Recorded as		
Regulatory Asset	$ 94	$ (38)
Deferred Income Taxes	6	(5)
Net of Tax AOCI	10	(9)
Total	$ 110	$ (52)

American Electric Power System Retirement Savings Plan

We sponsor the American Electric Power System Retirement Savings Plan, a defined contribution retirement savings plan for substantially all employees who are not covered by a retirement savings plan of the United Mine Workers of America (UMWA). It is a qualified plan offering participants an opportunity to contribute a portion of their pay with features under Section 401(k) of the Internal Revenue Code. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions totaled $70 million in 2014, $67 million in 2013 and $66 million in 2012.

UMWA Benefits

We provide UMWA pension, health and welfare benefits for certain unionized employees, retirees and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds. The health and welfare benefits are administered by us and benefits are paid from our general assets.

The UMWA pension benefits are administered through a multiemployer plan that is different from single-employer plans as an employer's contributions may be used to provide benefits to employees of other participating employers. Required contributions not made by any employer may result in other employers bearing the unfunded plan obligations, while a withdrawing employer may be subject to a withdrawal liability. UMWA pension benefits are provided through the United Mine Workers of America 1974 Pension Plan (Employer Identification Number: 52-1050282, Plan Number 2), which under the Pension Protection Act of 2006 (PPA) was in Critical Status for the plan year ending June 30, 2014 and in Seriously Endangered Status for the plan year ending June 30, 2013, without utilization of extended amortization provisions. The Plan adopted a funding improvement plan in May 2012, as required under the PPA.

Contributions to the UMWA pension plan in 2014, 2013 and 2012 were made under a collective bargaining agreement that is scheduled to expire December 31, 2017. We contributed immaterial amounts in 2014, 2013 and 2012 that represent less than 5% of the total contributions in the plan's latest annual report for the years ended June 30, 2014, 2013 and 2012. The contributions we made included a surcharge of 5% beginning December 2014 and are scheduled to include a surcharge of 10% beginning July 2015. There are no minimum contributions for future years.

Based upon the plan to retrofit the Rockport Plant with dry sorbent injection technology to meet environmental emission control requirements and the timing of the closure of Cook Coal Terminal expected to be in or after 2025, we recorded a UWMA withdrawal liability in 2013. The withdrawal liability regulatory asset recorded on the balance sheet should be recovered in future billings for transloading services before the planned closure. As of December 31, 2014 and 2013, the regulatory asset balance was $25 million and $27 million, respectively.

9. BUSINESS SEGMENTS

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

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

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 to serve SSO customers, and provides capacity for all connected load.

AEP Transmission Holdco

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

Generation & Marketing

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

AEP River Operations

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

The remainder of our activities is presented as Corporate and Other. While not considered a reportable segment, Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.

The tables below present our reportable segment income statement information for the years ended December 31, 2014, 2013 and 2012 and reportable segment balance sheet information as of December 31, 2014 and 2013. These amounts include certain estimates and allocations where necessary.

Year Ended December 31, 2014	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)				
Revenues from:								
External Customers	$ 9,397 (b)	$ 4,553	$ 74	$ 2,384 (b)	$ 642	$ 22	$ (52) (c)	$ 17,020
Other Operating Segments	87 (b)	261	118	1,466 (b)	58	73	(2,063)	—
Total Revenues	$ 9,484	$ 4,814	$ 192	$ 3,850	$ 700	$ 95	$ (2,115)	$ 17,020
Depreciation and Amortization	1,033	658	24	227	31	—	(44) (d)	1,929
Interest and Investment Income	4	11	—	5	—	7	(20)	7
Carrying Costs Income	6	27	—	—	—	—	—	33
Interest Expense	526	280	23	46	17	26	(33) (d)	885
Income Tax Expense	434	211	63	179	40	15	—	942
Net Income	712	355	151	367	49	4	—	1,638
Gross Property Additions	2,055	1,038	948	165	4	17	(28)	4,199

Year Ended December 31, 2013	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)				
Revenues from:								
External Customers	$ 9,347	$ 4,279	$ 27	$ 1,208	$ 544	$ 32	$ (80) (c)	$ 15,357
Other Operating Segments	645	199	51	2,457	19	57	(3,428)	—
Total Revenues	$ 9,992	$ 4,478	$ 78	$ 3,665	$ 563	$ 89	$ (3,508)	$ 15,357
Asset Impairments and Other Related Charges	$ 72	$ —	$ —	$ 154	$ —	$ —	$ —	$ 226
Depreciation and Amortization	941	591	10	236	31	—	(66) (d)	1,743
Interest and Investment Income	7	2	—	2	—	69	(22)	58
Carrying Costs Income	14	16	—	—	—	—	—	30
Interest Expense	540	292	10	55	17	27	(35) (d)	906
Income Tax Expense (Credit)	398	198	29	112	7	(60)	—	684
Net Income	681	358	80	228	12	125	—	1,484
Gross Property Additions	1,822	871	843	185	7	9	(81)	3,656

Year Ended December 31, 2012	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)				
Revenues from:								
External Customers	$ 8,785	$ 4,659	$ 7	$ 882	$ 647	$ 25	$ (60) (c)	$ 14,945
Other Operating Segments	633	159	17	2,585	20	58	(3,472)	—
Total Revenues	$ 9,418	$ 4,818	$ 24	$ 3,467	$ 667	$ 83	$ (3,532)	$ 14,945
Asset Impairments and Other Related Charges	$ 13	$ —	$ —	$ 287	$ —	$ —	$ —	$ 300
Depreciation and Amortization	873	561	3	349	29	—	(33) (d)	1,782
Interest and Investment Income	5	4	—	1	—	22	(24)	8
Carrying Costs Income	28	24	1	—	—	—	—	53
Interest Expense	520	291	3	83	17	112	(38) (d)	988
Income Tax Expense	345	201	17	15	7	19	—	604
Net Income (Loss)	803	389	43	100	15	(88)	—	1,262
Gross Property Additions	1,801	664	392	249	31	2	(20)	3,119

December 31, 2014	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)				
Total Property, Plant and Equipment	$ 39,402	$ 13,024	$ 2,714	$ 8,394	$ 700	$ 343	$ (272) (d)	$ 64,305
Accumulated Depreciation and Amortization	12,773	3,481	25	3,603	217	188	(99) (d)	20,188
Total Property, Plant and Equipment – Net	$ 26,629	$ 9,543	$ 2,689	$ 4,791	$ 483	$ 155	$ (173) (d)	$ 44,117
Total Assets	$ 33,750	$ 14,495	$ 3,575	$ 6,329	$ 749	$ 21,081	$ (20,346) (d) (e)	$ 59,633
Investments in Equity Method Investees	26	1	548	—	58	15	—	648
Long-term Debt Due Within One Year:								
Affiliated	$ 111	$ —	$ —	$ 86	$ —	$ —	$ (197)	$ —
Non-Affiliated	1,352	405	—	740	3	3	—	2,503
Long-term Debt:								
Affiliated	20	—	—	32	—	—	(52)	—
Non-Affiliated	8,634	5,256	1,153	217	80	841	—	16,181
Total Long-term Debt	$ 10,117	$ 5,661	$ 1,153	$ 1,075	$ 83	$ 844	$ (249)	$ 18,684

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)				
December 31, 2013								
Total Property, Plant and Equipment	$ 37,545	$ 12,143	$ 1,636	$ 8,277	$ 638	$ 315	$ (269) (d)	$ 60,285
Accumulated Depreciation and Amortization	12,250	3,342	10	3,409	189	173	(85) (d)	19,288
Total Property, Plant and Equipment – Net	$ 25,295	$ 8,801	$ 1,626	$ 4,868	$ 449	$ 142	$ (184) (d)	$ 40,997
Total Assets	$ 32,791	$ 14,165	$ 2,245	$ 6,426	$ 673	$ 19,645	$ (19,531) (d) (e)	$ 56,414
Investments in Equity Method Investees	24	—	480	—	54	11	—	569
Long-term Debt Due Within One Year:								
Affiliated	$ —	$ —	$ —	$ 179	$ 5	$ —	$ (184)	$ —
Non-Affiliated	720	697	—	126	2	4	—	1,549
Long-term Debt:								
Affiliated	151	—	—	118	10	—	(279)	—
Non-Affiliated	9,265	5,360	620	664	83	836	—	16,828
Total Long-term Debt	$ 10,136	$ 6,057	$ 620	$ 1,087	$ 100	$ 840	$ (463)	$ 18,377

(a) Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.

(b) Includes the impact of the corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013, as well as the impact of the termination of the Interconnection Agreement effective January 1, 2014.

(c) Reconciling Adjustments for External Customers primarily include eliminations as a result of corporate separation in Ohio.

(d) Includes eliminations due to an intercompany capital lease.

(e) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.

10. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

We are exposed to certain market risks as a major power producer and marketer of wholesale electricity, natural gas, coal and emission allowances. These risks include commodity price risk, interest rate risk, credit risk and, to a lesser extent, foreign currency exchange risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates. We manage these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

Our strategy surrounding the use of derivative instruments primarily focuses on managing our risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. Our risk management strategies also include the use of derivative instruments for trading purposes, focusing on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which we transact. To accomplish our objectives, we primarily employ risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

We enter into power, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with our energy business. We enter into interest rate derivative contracts in order to manage the interest rate exposure associated with our commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as they are related to energy risk management activities. We also engage in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. For disclosure purposes, these risks are grouped as "Interest Rate and Foreign Currency." The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with our established risk management policies as approved by the Finance Committee of our Board of Directors.

The following table represents the gross notional volume of our outstanding derivative contracts as of December 31, 2014 and 2013:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume December 31, 2014	Volume December 31, 2013	Unit of Measure
	(in millions)		
Commodity:			
Power	334	406	MWhs
Coal	3	4	Tons
Natural Gas	106	127	MMBtus
Heating Oil and Gasoline	6	6	Gallons
Interest Rate	$ 152	$ 191	USD
Interest Rate and Foreign Currency	$ 815	$ 820	USD

Fair Value Hedging Strategies

We enter into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives are designated as fair value hedges.

Cash Flow Hedging Strategies

We enter into and designate as cash flow hedges certain derivative transactions for the purchase and sale of power and natural gas ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. We monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative transactions to protect profit margins for a portion of future electricity sales and energy purchases. We do not hedge all commodity price risk.

Our vehicle fleet and barge operations are exposed to gasoline and diesel fuel price volatility. We enter into financial heating oil and gasoline derivative contracts in order to mitigate price risk of our future fuel purchases. We discontinued cash flow hedge accounting for these derivative contracts effective March 31, 2014. During the year ended December 31, 2013, we designated financial heating oil and gasoline derivatives as cash flow hedges. For disclosure purposes, these contracts were included with other hedging activities as "Commodity" as of December 31, 2013. In March 2014, these contracts were grouped as "Commodity" with other risk management activities. We do not hedge all fuel price risk.

We enter into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our floating-rate debt to a fixed rate. We also enter into interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. Our forecasted fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. We do not hedge all interest rate exposure.

At times, we are exposed to foreign currency exchange rate risks primarily when we purchase certain fixed assets from foreign suppliers. In accordance with our risk management policy, we may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. We do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON OUR FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of our derivative instruments, we also apply valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with our estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of our risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," we reflect the fair values of our derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, we are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2014 and 2013 balance sheets, we netted $4 million and $4 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $35 million and $13 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of our derivative activity on the balance sheets as of December 31, 2014 and 2013:

Fair Value of Derivative Instruments
December 31, 2014

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
			(in millions)			
Current Risk Management Assets	$ 392	$ 30	$ 3	$ 425	$ (247)	$ 178
Long-term Risk Management Assets	367	3	—	370	(76)	294
Total Assets	759	33	3	795	(323)	472
Current Risk Management Liabilities	329	23	1	353	(261)	92
Long-term Risk Management Liabilities	208	8	9	225	(94)	131
Total Liabilities	537	31	10	578	(355)	223
Total MTM Derivative Contract Net Assets (Liabilities)	$ 222	$ 2	$ (7)	$ 217	$ 32	$ 249

Fair Value of Derivative Instruments
December 31, 2013

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
			(in millions)			
Current Risk Management Assets	$ 347	$ 12	$ 4	$ 363	$ (203)	$ 160
Long-term Risk Management Assets	368	3	—	371	(74)	297
Total Assets	715	15	4	734	(277)	457
Current Risk Management Liabilities	292	11	1	304	(214)	90
Long-term Risk Management Liabilities	237	3	15	255	(78)	177
Total Liabilities	529	14	16	559	(292)	267
Total MTM Derivative Contract Net Assets (Liabilities)	$ 186	$ 1	$ (12)	$ 175	$ 15	$ 190

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

(b) Amounts primarily include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging." Amounts also include de-designated risk management contracts.

(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The table below presents our activity of derivative risk management contracts for the years ended December 31, 2014, 2013 and 2012:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2014	2013	2012
		(in millions)	
Vertically Integrated Utilities Revenues	$ 35	$ 15	$ 10
Generation & Marketing Revenues	53	49	50
Regulatory Assets (a)	(11)	(2)	(43)
Regulatory Liabilities (a)	193	(5)	8
Total Gain on Risk Management Contracts	$ 270	$ 57	$ 25

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the statements of income on an accrual basis.

Our accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, we designate a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the statements of income depending on the relevant facts and circumstances. However, unrealized and some realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk impacts Net Income during the period of change.

We record realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on the statements of income. The following table shows the results of our hedging gains (losses) during 2014, 2013, and 2012:

	Years Ended December 31, 2014	2013	2012
		(in millions)	
Gain (Loss) on Fair Value Hedging Instruments	$ 4	$ (10)	$ — (a)
Gain (Loss) on Fair Value Portion of Long-term Debt	(4)	10	— (a)

(a) The fair value changes were immaterial.

For 2014, 2013 and 2012, hedge ineffectiveness was immaterial.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects Net Income. We recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power and natural gas designated as cash flow hedges are included in Revenues or Purchased Electricity for Resale on the statements of income, or in Regulatory Assets or Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During 2014, 2013 and 2012, we designated power and natural gas derivatives as cash flow hedges.

We reclassify gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the statements of income. During 2013 and 2012, we designated heating oil and gasoline derivatives as cash flow hedges. The impact of cash flow hedge accounting for these derivative contracts was immaterial and was discontinued effective March 31, 2014.

We reclassify gains and losses on interest rate derivative hedges related to our debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During 2014, 2013 and 2012, we designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to our foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Depreciation and Amortization expense on the statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During 2014 and 2013, we did not designate any foreign currency derivatives as cash flow hedges. During 2012, we designated foreign currency derivatives as cash flow hedges.

During 2014, 2013 and 2012, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets and the reasons for changes in cash flow hedges for the years ended December 31, 2014, 2013 and 2012, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets as of December 31, 2014 and 2013 were:

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2014

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 16	$ —	$ 16
Hedging Liabilities (a)	14	1	15
AOCI Gain (Loss) Net of Tax	1	(19)	(18)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	4	(2)	2

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2013

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 7	$ —	$ 7
Hedging Liabilities (a)	6	2	8
AOCI Loss Net of Tax	—	(23)	(23)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	—	(4)	(4)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the balance sheets.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of December 31, 2014, the maximum length of time that we are hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") our exposure to variability in future cash flows related to forecasted transactions was 72 months.

Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. We use Moody's, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

When we use standardized master agreements, these agreements may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds our established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with our credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs), a limited number of derivative and non-derivative contracts primarily related to our competitive retail auction loads, and guaranties for contractual obligations, we are obligated to post an additional amount of collateral if our credit ratings decline below a specified rating threshold. The amount of collateral required fluctuates based on market prices and our total exposure. On an ongoing basis, our risk management organization assesses the appropriateness of these collateral triggering items in contracts. AEP and its subsidiaries have not experienced a downgrade below a specified rating threshold that would require the posting of additional collateral. The following table represents our exposure if our credit ratings were to decline below a specified rating threshold as of December 31, 2014 and 2013:

	December 31, 2014	December 31, 2013
	(in millions)	
Fair Value of Contracts with Credit Downgrade Triggers	$ —	$ 3
Amount of Collateral AEP Subsidiaries Would Have been Required to Post for Derivative Contracts as well as Derivative and Non-Derivative Contracts Subject to the Same Master Netting Arrangement	—	—
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post Attributable to RTOs and ISOs	36	28
Amount of Collateral Attributable to Other Contracts (a)	281	5

(a) Represents the amount of collateral AEP subsidiaries would have been required to post for other significant non-derivative contracts including AGR jointly owned plant contracts and various other commodity related contacts.

In addition, a majority of our non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, our risk management organization assesses the appropriateness of these cross-default provisions in our contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral we have posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering our contractual netting arrangements as of December 31, 2014 and 2013:

	December 31, 2014	December 31, 2013
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 235	$ 293
Amount of Cash Collateral Posted	9	1
Additional Settlement Liability if Cross Default Provision is Triggered	178	235

11. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that we could realize in a current market exchange.

The book values and fair values of Long-term Debt as of December 31, 2014 and 2013 are summarized in the following table:

	December 31,			
	2014		2013	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 18,684	$ 21,075	$ 18,377	$ 19,672

Fair Value Measurements of Other Temporary Investments

Other Temporary Investments include funds held by trustees primarily for the payment of securitization bonds and securities available for sale, including marketable securities that we intend to hold for less than one year and investments by our protected cell of EIS. See "Other Temporary Investments" section of Note 1.

The following is a summary of Other Temporary Investments:

	December 31, 2014			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
		(in millions)		
Restricted Cash (a)	$ 280	$ —	$ —	$ 280
Fixed Income Securities – Mutual Funds	81	—	—	81
Equity Securities – Mutual Funds	13	12	—	25
Total Other Temporary Investments	$ 374	$ 12	$ —	$ 386

	December 31, 2013			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
		(in millions)		
Restricted Cash (a)	$ 250	$ —	$ —	$ 250
Fixed Income Securities – Mutual Funds	80	—	—	80
Equity Securities – Mutual Funds	12	11	—	23
Total Other Temporary Investments	$ 342	$ 11	$ —	$ 353

(a) Primarily represents amounts held for the repayment of debt.

The following table provides the activity for our fixed income and equity securities within Other Temporary Investments for the years ended December 31, 2014, 2013 and 2012:

	Years Ended December 31,		
	2014	2013	2012
	(in millions)		
Proceeds from Investment Sales	$ —	$ —	$ —
Purchases of Investments	2	17	2
Gross Realized Gains on Investment Sales	—	—	—
Gross Realized Losses on Investment Sales	—	—	—

As of December 31, 2014 and 2013, we had no Other Temporary Investments with an unrealized loss position. As of December 31, 2014, fixed income securities were primarily debt based mutual funds with short and intermediate maturities. Mutual funds may be sold and do not contain maturity dates.

For details of the reasons for changes in securities available for sale included in Accumulated Other Comprehensive Income (Loss) for the years ended December 31, 2014 and 2013, see Note 3.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. See "Nuclear Trust Funds" section of Note 1.

The following is a summary of nuclear trust fund investments as of December 31, 2014 and 2013:

	December 31,					
	2014			2013		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 20	$ —	$ —	$ 19	$ —	$ —
Fixed Income Securities:						
United States Government	697	45	(5)	609	26	(4)
Corporate Debt	48	4	(1)	37	2	(1)
State and Local Government	208	1	—	255	1	—
Subtotal Fixed Income Securities	953	50	(6)	901	29	(5)
Equity Securities – Domestic	1,123	599	(79)	1,012	506	(82)
Spent Nuclear Fuel and Decommissioning Trusts	$ 2,096	$ 649	$ (85)	$ 1,932	$ 535	$ (87)

The following table provides the securities activity within the decommissioning and SNF trusts for the years ended December 31, 2014, 2013 and 2012:

	Years Ended December 31,		
	2014	2013	2012
	(in millions)		
Proceeds from Investment Sales	$ 1,032	$ 858	$ 988
Purchases of Investments	1,086	910	1,045
Gross Realized Gains on Investment Sales	32	18	25
Gross Realized Losses on Investment Sales	15	8	9

The adjusted cost of fixed income securities was $903 million and $872 million as of December 31, 2014 and 2013, respectively. The adjusted cost of equity securities was $524 million and $506 million as of December 31, 2014 and 2013, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2014 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 154
1 year – 5 years	376
5 years – 10 years	179
After 10 years	244
Total	$ 953

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2014 and 2013. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in our valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2014

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 17	$ 1	$ —	$ 145	$ 163
Other Temporary Investments					
Restricted Cash (a)	234	9	—	37	280
Fixed Income Securities – Mutual Funds	81	—	—	—	81
Equity Securities – Mutual Funds (b)	25	—	—	—	25
Total Other Temporary Investments	340	9	—	37	386
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	37	528	190	(302)	453
Cash Flow Hedges:					
Commodity Hedges (c)	—	32	—	(16)	16
Fair Value Hedges	—	1	—	2	3
Total Risk Management Assets	37	561	190	(316)	472
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	9	—	—	11	20
Fixed Income Securities:					
United States Government	—	697	—	—	697
Corporate Debt	—	48	—	—	48
State and Local Government	—	208	—	—	208
Subtotal Fixed Income Securities	—	953	—	—	953
Equity Securities – Domestic (b)	1,123	—	—	—	1,123
Total Spent Nuclear Fuel and Decommissioning Trusts	1,132	953	—	11	2,096
Total Assets	$ 1,526	$ 1,524	$ 190	$ (123)	$ 3,117
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 65	$ 432	$ 36	$ (334)	$ 199
Cash Flow Hedges:					
Commodity Hedges (c)	—	27	3	(16)	14
Interest Rate/Foreign Currency Hedges	—	1	—	—	1
Fair Value Hedges	—	7	—	2	9
Total Risk Management Liabilities	$ 65	$ 467	$ 39	$ (348)	$ 223

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2013

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 16	$ 1	$ —	$ 101	$ 118
Other Temporary Investments					
Restricted Cash (a)	231	8	—	11	250
Fixed Income Securities – Mutual Funds	80	—	—	—	80
Equity Securities – Mutual Funds (b)	23	—	—	—	23
Total Other Temporary Investments	334	8	—	11	353
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	22	549	142	(273)	440
Cash Flow Hedges:					
Commodity Hedges (c)	—	15	—	(8)	7
Fair Value Hedges	—	1	—	3	4
De-designated Risk Management Contracts (e)	—	—	—	6	6
Total Risk Management Assets	22	565	142	(272)	457
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	8	—	—	11	19
Fixed Income Securities:					
United States Government	—	609	—	—	609
Corporate Debt	—	37	—	—	37
State and Local Government	—	255	—	—	255
Subtotal Fixed Income Securities	—	901	—	—	901
Equity Securities – Domestic (b)	1,012	—	—	—	1,012
Total Spent Nuclear Fuel and Decommissioning Trusts	1,020	901	—	11	1,932
Total Assets	$ 1,392	$ 1,475	$ 142	$ (149)	$ 2,860
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ 30	$ 475	$ 22	$ (282)	$ 245
Cash Flow Hedges:					
Commodity Hedges (c)	—	11	3	(8)	6
Interest Rate/Foreign Currency Hedges	—	2	—	—	2
Fair Value Hedges	—	11	—	3	14
Total Risk Management Liabilities	$ 30	$ 499	$ 25	$ (287)	$ 267

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.

(b) Amounts represent publicly traded equity securities and equity-based mutual funds.

(c) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."

(d) The December 31, 2014 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $(18) million in 2015 and $(10) million in periods 2016-2018; Level 2 matures $31 million in 2015, $52 million in periods 2016-2018, $12 million in periods 2019-2020 and $1 million in periods 2021-2030; Level 3 matures $50 million in 2015, $29 million in periods 2016-2018, $9 million in periods 2019-2020 and $66 million in periods 2021-2030. Risk management commodity contracts are substantially comprised of power contracts.

(e) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.

(f) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 1 amounts primarily represent investments in money market funds.

(g) The December 31, 2013 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $4 million in 2014, $(11) million in periods 2015-2017 and $(1) million in periods 2018-2019; Level 2 matures $25 million in 2014, $37 million in periods 2015-2017, $7 million in periods 2018-2019 and $5 million in periods 2020-2030; Level 3 matures $27 million in 2014, $60 million in periods 2015-2017, $14 million in periods 2018-2019 and $19 million in periods 2020-2030. Risk management commodity contracts are substantially comprised of power contracts.

There have been no transfers between Level 1 and Level 2 during the years ended December 31, 2014, 2013 and 2012.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives and other investments classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 2014	Net Risk Management Assets (Liabilities)
	(in millions)
Balance as of December 31, 2013	$ 117
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	90
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	6
Purchases, Issuances and Settlements (c)	(108)
Transfers into Level 3 (d) (e)	(8)
Transfers out of Level 3 (e) (f)	(21)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	75
Balance as of December 31, 2014	$ 151

Year Ended December 31, 2013	Net Risk Management Assets (Liabilities)
	(in millions)
Balance as of December 31, 2012	$ 86
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(9)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	37
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(3)
Purchases, Issuances and Settlements (c)	(16)
Transfers into Level 3 (d) (e)	19
Transfers out of Level 3 (e) (f)	(4)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	7
Balance as of December 31, 2013	$ 117

Year Ended December 31, 2012	Net Risk Management Assets (Liabilities)
	(in millions)
Balance as of December 31, 2011	$ 69
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(15)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	29
Purchases, Issuances and Settlements (c)	32
Transfers into Level 3 (d) (e)	1
Transfers out of Level 3 (e) (f)	(35)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	5
Balance as of December 31, 2012	$ 86

(a) Included in revenues on the statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Represents existing assets or liabilities that were previously categorized as Level 3.
(g) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

The following tables quantify the significant unobservable inputs used in developing the fair value of our Level 3 positions as of December 31, 2014 and 2013:

Significant Unobservable Inputs
December 31, 2014

	Fair Value		Valuation Technique	Significant Unobservable Input	Input/Range		
	Assets	Liabilities			Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 157	$ 37	Discounted Cash Flow	Forward Market Price (a)	$ 11.37	$ 159.92	$ 57.18
				Counterparty Credit Risk (b)		303	
FTRs	33	2	Discounted Cash Flow	Forward Market Price (a)	(14.63)	20.02	0.96
Total	$ 190	$ 39					

Significant Unobservable Inputs
December 31, 2013

	Fair Value		Valuation Technique	Significant Unobservable Input	Input/Range	
	Assets	Liabilities			Low	High
	(in millions)					
Energy Contracts	$ 132	$ 22	Discounted Cash Flow	Forward Market Price (a)	$ 11.42	$ 120.72
				Counterparty Credit Risk (b)	316	
FTRs	10	3	Discounted Cash Flow	Forward Market Price (a)	(5.10)	10.44
Total	$ 142	$ 25				

(a) Represents market prices in dollars per MWh.
(b) Represents average price of credit default swaps used to calculate counterparty credit risk, reported in basis points.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs as of December 31, 2014:

Sensitivity of Fair Value Measurements
December 31, 2014

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)
Counterparty Credit Risk	Loss	Increase (Decrease)	Higher (Lower)
Counterparty Credit Risk	Gain	Increase (Decrease)	Lower (Higher)

12. INCOME TAXES

The details of our consolidated income taxes as reported are as follows:

	Years Ended December 31,		
	2014	2013	2012
		(in millions)	
Federal:			
Current	$ 51	$ (45)	$ (52)
Deferred	796	676	698
Total Federal	847	631	646
State and Local:			
Current	25	29	35
Deferred	70	24	(77)
Total State and Local	95	53	(42)
Income Tax Expense	$ 942	$ 684	$ 604

The following is a reconciliation of our consolidated difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory tax rate and the amount of income taxes reported:

	Years Ended December 31,		
	2014	2013	2012
		(in millions)	
Net Income	$ 1,638	$ 1,484	$ 1,262
Income Tax Expense	942	684	604
Pretax Income	$ 2,580	$ 2,168	$ 1,866
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 903	$ 759	$ 653
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	54	47	39
Investment Tax Credits, Net	(13)	(14)	(14)
State and Local Income Taxes, Net	64	29	(33)
Removal Costs	(24)	(21)	(18)
AFUDC	(42)	(31)	(39)
Valuation Allowance	(2)	5	6
U.K. Windfall Tax	—	(80)	15
Other	2	(10)	(5)
Income Tax Expense	$ 942	$ 684	$ 604
Effective Income Tax Rate	36.5 %	31.5 %	32.4 %

The following table shows elements of the net deferred tax liability and significant temporary differences:

	December 31, 2014	2013
	(in millions)	
Deferred Tax Assets	$ 2,653	$ 2,900
Deferred Tax Liabilities	(13,599)	(13,088)
Net Deferred Tax Liabilities	$ (10,946)	$ (10,188)
Property Related Temporary Differences	$ (7,968)	$ (7,508)
Amounts Due from Customers for Future Federal Income Taxes	(255)	(273)
Deferred State Income Taxes	(811)	(765)
Securitized Assets	(753)	(870)
Regulatory Assets	(694)	(609)
Deferred Income Taxes on Other Comprehensive Loss	60	66
Accrued Nuclear Decommissioning	(611)	(554)
Net Operating Loss Carryforward	47	233
Tax Credit Carryforward	144	109
Valuation Allowance	(56)	(97)
All Other, Net	(49)	80
Net Deferred Tax Liabilities	$ (10,946)	$ (10,188)

AEP System Tax Allocation Agreement

We, along with our subsidiaries, file a consolidated federal income tax return. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to our subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

Federal and State Income Tax Audit Status

We are no longer subject to U.S. federal examination for years before 2011. The IRS examination of years 2011, 2012 and 2013 started in April 2014. Although the outcome of tax audits is uncertain, in our opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, we accrue interest on these uncertain tax positions. We are not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

We, along with our subsidiaries, file income tax returns in various state, local and foreign jurisdictions. These taxing authorities routinely examine our tax returns and we are currently under examination in several state and local jurisdictions. However, it is possible that we have filed tax returns with positions that may be challenged by these tax authorities. We believe that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and the ultimate resolution of these audits will not materially impact net income. We are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2009.

Net Income Tax Operating Loss Carryforward

In 2012 and 2011, we recognized federal net income tax operating losses of $366 million and $226 million, respectively, driven primarily by bonus depreciation, pension plan contributions and other book-versus-tax temporary differences. As of December 31, 2013, we had $156 million of unrealized federal net operating loss carryforward tax benefits. Federal taxable income was sufficient enough in 2014 that these remaining federal net income tax operating loss tax benefits were realized in full. We recognized deferred state and local income tax benefits in 2012 and 2011. The state net income tax operating loss carryforwards as of December 31, 2014 are indicated in the table below:

State	State Net Income Tax Operating Loss Carryforward	Year of Expiration
	(in millions)	
Louisiana	$ 431	2029
Missouri	9	2034
Oklahoma	322	2034
Tennessee	3	2026
West Virginia	286	2032

We anticipate future taxable income will be sufficient to realize the remaining state net income tax operating loss tax benefits before the state carryforward expires for each state.

As of December 31, 2013 we had $121 million of uncertain tax positions netted against the federal net income tax operating loss carryforward tax benefits. Due to the utilization of the net operating loss carryforward in 2014, $69 million is presented as a non-current uncertain tax position. As of December 31, 2014, we have $52 million of uncertain tax positions netted against tax credit and alternative minimum tax carryforward tax benefits.

Tax Credit Carryforward

Federal and state net income tax operating losses sustained in 2012, 2011 and 2009, along with lower federal and state taxable income in 2010, resulted in unused federal and state income tax credits. As of December 31, 2014, we have total federal tax credit carryforwards of $144 million and total state tax credit carryforwards of $22 million, not all of which are subject to an expiration date. If these credits are not utilized, the federal general business tax credits of $74 million will expire in the years 2028 through 2033.

We anticipate future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused.

In November 2014, APCo received an order from the Virginia SCC for its 2014 Virginia Biennial Base Rate Case (see Note 4). As a result of the final determination pertaining to the ability to realize future tax benefits for certain state net income tax operating loss and credit carryforwards, we determined that APCo is subject to the Virginia Minimum Tax on electric suppliers and the Virginia State Income Tax is no longer applicable. As a result, we derecognized the related state income tax benefits, which had been subject to valuation allowances.

Valuation Allowance

We assess past results and future operations to estimate and evaluate available positive and negative evidence to evaluate whether sufficient future taxable income will be generated to use existing deferred tax assets. The positive evidence we considered is the history of positive pretax income and the fact that the tax losses resulted from temporary differences that will reverse in future periods. On the basis of the evaluation of all available positive and negative evidence, as of December 31, 2014, a valuation allowance of $56 million for an unrealized capital loss has been recorded in order to recognize only the portion of the deferred tax assets that, more likely than not, will be realized. The amount of the deferred tax assets realizable, however, could be adjusted if estimates of future taxable income during the carryforward period are materially impacted.

Uncertain Tax Positions

In May 2013, the U.S. Supreme Court decided that the U.K. Windfall Tax imposed upon U.K. electric companies privatized between 1984 and 1996 is a creditable tax for U.S. federal income tax purposes. We filed protective claims asserting the creditability of the tax, dependent upon the outcome of the case. As a result of the favorable U.S. Supreme Court decision, we recognized a tax benefit of $80 million, plus $43 million of pretax interest income in the second quarter of 2013. The tax benefit and interest income resulted in an increase in net income of $108 million, but did not result in the receipt of cash as of December 31, 2014. Due to the timing of the IRS audit cycle, receipt of cash is not expected within the next 12 months.

We recognize interest accruals related to uncertain tax positions in interest income or expense, as applicable, and penalties in Other Operation expense in accordance with the accounting guidance for "Income Taxes."

The following table shows amounts reported for interest expense, interest income and reversal of prior period interest expense:

	Years Ended December 31,		
	2014	2013	2012
	(in millions)		
Interest Expense	$ 3	$ 1	$ 11
Interest Income	1	51	—
Reversal of Prior Period Interest Expense	2	—	1

The following table shows balances for amounts accrued for the receipt of interest and the payment of interest and penalties:

	December 31,	
	2014	2013
	(in millions)	
Accrual for Receipt of Interest	$ 44	$ 43
Accrual for Payment of Interest and Penalties	6	5

The reconciliations of the beginning and ending amounts of unrecognized tax benefits are as follows:

	2014	2013	2012
		(in millions)	
Balance as of January 1,	$ 175	$ 267	$ 168
Increase – Tax Positions Taken During a Prior Period	18	—	23
Decrease – Tax Positions Taken During a Prior Period	(1)	(94)	(16)
Increase – Tax Positions Taken During the Current Year	—	2	121
Decrease – Tax Positions Taken During the Current Year	—	—	—
Decrease – Settlements with Taxing Authorities	(1)	—	(25)
Decrease – Lapse of the Applicable Statute of Limitations	(9)	—	(4)
Balance as of December 31,	$ 182	$ 175	$ 267

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $97 million, $87 million and $149 million for 2014, 2013 and 2012, respectively. We believe there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

The American Taxpayer Relief Act of 2012 (the 2012 Act) was enacted in January 2013. Included in the 2012 Act was a one-year extension of 50% bonus depreciation. The 2012 Act also retroactively extended the life of research and development, employment and several energy tax credits, which expired at the end of 2011. The enacted provisions did not materially impact net income or financial condition but did have a favorable impact on cash flows in 2013.

The Tax Increase Prevention Act of 2014 (the 2014 Act) was enacted in December 2014. Included in the 2014 Act was a one-year extension of the 50% bonus depreciation. The 2014 Act also retroactively extended the life of research and development, employment and several energy tax credits, which expired at the end of 2013. The enacted provisions did not materially impact net income or financial condition but will have a favorable impact on future cash flows.

Federal Tax Regulations

In 2013, the U.S. Treasury Department issued final and re-proposed regulations regarding the deduction and capitalization of expenditures related to tangible property, effective for the tax years beginning in 2014. In addition, the IRS issued Revenue Procedures under the Industry Issue Resolutions program that provides specific guidance for the implementation of the regulations for the electric utility industry. These final regulations did not materially impact net income, cash flows or financial condition.

State Tax Legislation

Legislation was passed by the state of Indiana in May 2011 enacting a phased reduction in corporate income tax rate from 8.5% to 6.5%. The 8.5% Indiana corporate income tax rate will be reduced 0.5% each year beginning after June 30, 2012 with the final reduction occurring in years beginning after June 30, 2015.

In May 2011, Michigan repealed its Business Tax regime and replaced it with a traditional corporate net income tax rate of 6%, effective January 1, 2012.

During the third quarter of 2013, it was determined that the state of West Virginia had achieved certain minimum levels of shortfall reserve funds. As a result, the West Virginia corporate income tax rate was reduced from 7% to 6.5% in 2014.

The enacted provisions did not materially impact net income, cash flows or financial condition.

13. LEASES

Leases of property, plant and equipment are for remaining periods up to 35 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Additionally, for regulated operations with capital leases, a capital lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

	Years Ended December 31,		
Lease Rental Costs	**2014**	**2013**	**2012**
		(in millions)	
Net Lease Expense on Operating Leases	$ 304	$ 327	$ 346
Amortization of Capital Leases	109	74	73
Interest on Capital Leases	26	28	29
Total Lease Rental Costs	$ 439	$ 429	$ 448

The following table shows the property, plant and equipment under capital leases and related obligations recorded on the balance sheets. Capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on the balance sheets.

	December 31,	
Property, Plant and Equipment Under Capital Leases	**2014**	**2013**
	(in millions)	
Generation	$ 104	$ 103
Other Property, Plant and Equipment	683	627
Total Property, Plant and Equipment Under Capital Leases	787	730
Accumulated Amortization	240	197
Net Property, Plant and Equipment Under Capital Leases	$ 547	$ 533
Obligations Under Capital Leases		
Noncurrent Liability	$ 441	$ 428
Liability Due Within One Year	111	110
Total Obligations Under Capital Leases	$ 552	$ 538

Future minimum lease payments consisted of the following as of December 31, 2014:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2015	$ 134	$ 293
2016	120	267
2017	98	253
2018	63	239
2019	46	223
Later Years	239	693
Total Future Minimum Lease Payments	700	$ 1,968
Less Estimated Interest Element	148	
Estimated Present Value of Future Minimum Lease Payments	$ 552	

Master Lease Agreements

We lease certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, we are committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term, the fair value has been in excess of the unamortized balance. As of December 31, 2014, the maximum potential loss for these lease agreements was approximately $26 million assuming the fair value of the equipment is zero at the end of the lease term.

Rockport Lease

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant, Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it equally to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. AEP, AEGCo and I&M have no ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2014 are as follows:

Future Minimum Lease Payments	AEGCo	I&M
	(in millions)	
2015	$ 74	$ 74
2016	74	74
2017	74	74
2018	74	74
2019	74	74
Later Years	222	222
Total Future Minimum Lease Payments	$ 592	$ 592

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $11 million and $13 million for I&M and SWEPCo, respectively, for the remaining railcars as of December 31, 2014. These obligations are included in the future minimum lease payments schedule earlier in this note.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 83% of the projected fair value of the equipment under the current five-year lease term to 77% at the end of the 20-year term. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. The maximum potential losses related to the guarantee are approximately $9 million and $10 million for I&M and SWEPCo, respectively, assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair value would produce a sufficient sales price to avoid any loss.

Sabine Dragline Lease

During 2009, Sabine entered into capital lease arrangements with a nonaffiliated company to finance the purchase of two electric draglines to be used for Sabine's mining operations totaling $47 million. The amounts included in the lease represented the aggregate fair value of the existing equipment and a sale-and-leaseback transaction for additional dragline rebuild costs required to keep the dragline operational. These capital lease assets are included in Other Property, Plant and Equipment on our December 31, 2014 and 2013 balance sheets. The short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on our December 31, 2014 and 2013 balance sheets. The future payment obligations are included in our future minimum lease payments schedule earlier in this note.

I&M Nuclear Fuel Lease

In November 2013, I&M entered into a sale-and-leaseback transaction with IMP 11-2013, a nonaffiliated Ohio Trust, to lease nuclear fuel for I&M's Cook Plant. In November 2013, I&M sold a portion of its unamortized nuclear fuel inventory to the trust for $110 million. The lease has a variable rate based on one month LIBOR and is accounted for as a capital lease with lease terms up to 54 months. The future payment obligations of $67 million are included in our future minimum lease payments schedule earlier in this note. The net capital lease asset is included in Other Property, Plant and Equipment and the short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities, respectively, on our December 31, 2014 balance sheet. The future minimum lease payments for the sale-and-leaseback transaction as of December 31, 2014 are as follows, based on estimated fuel burn:

Future Minimum Lease Payments	I&M
	(in millions)
2015	$ 32
2016	27
2017	6
2018	2
Total Future Minimum Lease Payments	$ 67

14. FINANCING ACTIVITIES

AEP Common Stock

Listed below is a reconciliation of common stock share activity for the years ended December 31, 2014, 2013 and 2012:

Shares of AEP Common Stock	Issued	Held in Treasury
Balance, December 31, 2011	503,759,460	20,336,592
Issued	2,245,502	—
Balance, December 31, 2012	506,004,962	20,336,592
Issued	2,109,002	—
Balance, December 31, 2013	508,113,964	20,336,592
Issued	1,625,195	—
Balance, December 31, 2014	509,739,159	20,336,592

Long-term Debt

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

Type of Debt and Maturity	Weighted Average Interest Rate as of December 31, 2014	Interest Rate Ranges as of December 31, 2014	Interest Rate Ranges as of December 31, 2013	Outstanding as of December 31, 2014	Outstanding as of December 31, 2013
				(in millions)	
Senior Unsecured Notes					
2014-2044	5.34%	1.65%-8.13%	1.65%-8.13%	$ 12,647	$ 11,799
Pollution Control Bonds (a)					
2014-2038 (b)	2.66%	0.04%-6.30%	0.02%-6.30%	1,963	1,932
Notes Payable (c)					
2014-2032	3.84%	0.983%-8.03%	1.164%-8.03%	357	369
Securitization Bonds					
2015-2031	3.69%	0.88%-6.25%	0.88%-6.25%	2,380	2,686
Spent Nuclear Fuel Obligation (d)				266	265
Other Long-term Debt					
2015-2059	1.67%	1.15%-13.718%	1.15%-13.718%	1,101	1,360
Fair Value of Interest Rate Hedges				(6)	(9)
Unamortized Discount, Net				(24)	(25)
Total Long-term Debt Outstanding				18,684	18,377
Long-term Debt Due Within One Year				2,503	1,549
Long-term Debt				$ 16,181	$ 16,828

(a) For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and insurance policies support certain series.

(b) Certain pollution control bonds are subject to redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year on the balance sheets.

(c) Notes payable represent outstanding promissory notes issued under term loan agreements and credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.

(d) Spent nuclear fuel obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see "SNF Disposal" section of Note 6).

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

	2015	2016	2017	2018	2019	After 2019	Total
				(in millions)			
Principal Amount	$ 2,503	$ 1,306	$ 1,871	$ 1,417	$ 1,673	$ 9,938	$ 18,708
Unamortized Discount, Net							(24)
Total Long-term Debt Outstanding							$ 18,684

In January 2015 and February 2015, I&M retired $15 million and $8 million, respectively, of Notes Payable related to DCC Fuel.

In January 2015, OPCo retired $22 million of Securitization Bonds.

In January 2015, PSO issued $87.5 million of 3.17% and $87.5 million of 4.09% Senior Unsecured Notes due in 2025 and 2045, respectively.

In January 2015, SWEPCo remarketed $54 million of 1.6% Pollution Control Bonds due in 2019.

In January 2015, TCC retired $120 million of Securitization Bonds.

In February 2015, APCo retired $11 million of Securitization Bonds.

As of December 31, 2014, trustees held, on our behalf, $385 million of our reacquired Pollution Control Bonds.

Dividend Restrictions

Parent Restrictions

The holders of our common stock are entitled to receive the dividends declared by our Board of Directors provided funds are legally available for such dividends. Our income derives from our common stock equity in the earnings of our utility subsidiaries.

Pursuant to the leverage restrictions in our credit agreements, we must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization of the company distributing the dividend. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements. None of AEP's retained earnings were restricted for the purpose of the payment of dividends.

Utility Subsidiaries' Restrictions

Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends. Specifically, several of our public utility subsidiaries have credit agreements that contain a covenant that limits their debt to capitalization ratio to 67.5%. As of December 31, 2014, the amount of restricted net assets of AEP's subsidiaries that may not be distributed to Parent in the form of a loan, advance or dividend was approximately $7 billion.

The Federal Power Act prohibits the utility subsidiaries from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." The term "capital account" is not defined in the Federal Power Act or its regulations. Management understands "capital account" to mean the book value of the common stock. This restriction does not limit the ability of the utility subsidiaries to pay dividends out of retained earnings.

Lines of Credit and Short-term Debt

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of December 31, 2014, we had credit facilities totaling $3.5 billion to support our commercial paper program. The maximum amount of commercial paper outstanding during 2014 was $877 million and the weighted average interest rate of commercial paper outstanding during 2014 was 0.29%. Our outstanding short-term debt was as follows:

	December 31,			
	2014		2013	
Type of Debt	Outstanding Amount	Interest Rate (a)	Outstanding Amount	Interest Rate (a)
	(in millions)		(in millions)	
Securitized Debt for Receivables (b)	$ 744	0.22%	$ 700	0.23%
Commercial Paper	602	0.59%	57	0.29%
Total Short-term Debt	$ 1,346		$ 757	

(a) Weighted average rate.

(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.

Credit Facilities

For a discussion of credit facilities, see “Letters of Credit” section of Note 6.

Securitized Accounts Receivable – AEP Credit

AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the receivables AEP Credit acquires from affiliated utility subsidiaries. AEP Credit continues to service the receivables. These securitized transactions allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies’ receivables and accelerate AEP Credit’s cash collections.

Our receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement was increased in June 2014 from $700 million and expires in June 2016.

Accounts receivable information for AEP Credit is as follows:

	Years Ended December 31,		
	2014	2013	2012
	(dollars in millions)		
Effective Interest Rates on Securitization of Accounts Receivable	0.22%	0.23%	0.26%
Net Uncollectible Accounts Receivable Written Off	$ 40	$ 35	$ 29

	December 31, 2014	2013
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 975	$ 929
Total Principal Outstanding	744	700
Delinquent Securitized Accounts Receivable	44	45
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	13	16
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	335	331

Customer accounts receivable retained and securitized for our operating companies are managed by AEP Credit. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

15. STOCK-BASED COMPENSATION

As approved by shareholder vote, the Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP) authorizes the use of 20 million shares of AEP common stock for various types of stock-based compensation awards to employees. A maximum of 10 million shares may be used under this plan for full value share awards, which includes performance units, restricted shares and restricted stock units. As of December 31, 2014, 15,825,643 shares remained available for issuance under the LTIP plan. The AEP Board of Directors and shareholders last approved the LTIP in 2010. The following sections provide further information regarding each type of stock-based compensation award granted by the Human Resources Committee of our Board of Directors (HR Committee).

Stock Options

We did not grant stock options in 2014, 2013 or 2012. We did have outstanding stock options from grants in earlier periods that were exercised in 2013 and 2012. As of December 31, 2014, we have no outstanding stock options. We recorded compensation cost for stock options over the vesting period based on the fair value on the grant date. The LTIP does not specify a maximum contractual term for stock options.

The total intrinsic value of options exercised is as follows:

Stock Options	Years Ended December 31, 2014	2013	2012
		(in thousands)	
Intrinsic Value of Options Exercised (a)	$ —	$ 3,105	$ 1,699

(a) Intrinsic value is calculated as market price at exercise dates less the option exercise price.

A summary of AEP stock option transactions during the years ended December 31, 2014, 2013 and 2012 is as follows:

	2014		2013		2012	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
	(in thousands)		(in thousands)		(in thousands)	
Outstanding as of January 1,	—	NA	188	$ 30.17	321	$ 29.35
Granted	—	NA	—	NA	—	NA
Exercised/Converted	—	NA	(187)	30.18	(128)	28.21
Forfeited/Expired	—	NA	(1)	27.95	(5)	27.26
Outstanding as of December 31,	—	NA	—	NA	188	30.17
Options Exercisable as of December 31,	—	NA	—	NA	188	$ 30.17

NA Not applicable.

We include the proceeds received from exercised stock options in common stock and paid-in capital.

Performance Units

Our performance units have a fair value upon vesting equal to the average closing market price of AEP common stock for the last 20 trading days of the performance period. The number of performance units held is multiplied by the performance score to determine the actual number of performance units realized. The performance score can range from 0% to 200% and is determined at the end of the performance period based on performance measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the HR Committee. Performance units are paid in cash, unless they are needed to satisfy a participant's stock ownership requirement. In that case, the number of units needed to satisfy the participant's largest stock ownership requirement is mandatorily deferred as AEP Career Shares until after the end of the participant's AEP career. AEP

Career Shares are a form of non-qualified deferred compensation that has a value equivalent to shares of AEP common stock. AEP Career Shares are paid in cash after the participant's termination of employment. Amounts equivalent to cash dividends on both performance units and AEP Career Shares accrue as additional units. We record compensation cost for performance units over a three-year vesting period. The liability for both the performance units and AEP Career Shares, recorded in Employee Benefits and Pension Obligations on the balance sheets, is adjusted for changes in value. The fair value of performance unit awards is based on the estimated performance score and the current 20-day average closing price of AEP common stock at the date of valuation.

The HR Committee awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the years ended December 31, 2014, 2013 and 2012 as follows:

	Years Ended December 31,		
Performance Units	**2014**	**2013**	**2012**
Awarded Units (in thousands)	17	1,284	546
Weighted Average Unit Fair Value at Grant Date	$ 49.73	$ 46.23	$ 41.38
Vesting Period (in years)	3	3	3

	Years Ended December 31,		
Performance Units and AEP Career Shares (Reinvested Dividends Portion)	**2014**	**2013**	**2012**
Awarded Units (in thousands)	99	101	138
Weighted Average Fair Value at Grant Date	$ 53.35	$ 45.42	$ 40.97
Vesting Period (in years)	(a)	(a)	(a)

(a) The vesting period for the reinvested dividends on performance units is equal to the remaining life of the related performance units. Dividends on AEP Career Shares vest immediately upon grant but are not paid in cash until after the participant's termination of employment.

Performance scores and final awards are determined and certified by the HR Committee in accordance with the pre-established performance measures within approximately a month after the end of the performance period. The HR Committee has discretion to reduce or eliminate the number of performance units earned but may not increase the number earned. The performance scores for all open performance periods are dependent on two equally-weighted performance measures: (a) three-year total shareholder return measured relative to the Electric Utilities Industry Standard and Poor's 500 Index and (b) three-year cumulative earnings per share measured relative to an AEP Board of Directors approved target.

The certified performance scores and units earned for the three-year periods ended December 31, 2014, 2013 and 2012 were as follows:

	Years Ended December 31,		
Performance Units	**2014**	**2013**	**2012**
Certified Performance Score	147.8%	118.8%	99.7%
Performance Units Earned	889,697	749,219	1,096,572
Performance Units Mandatorily Deferred as AEP Career Shares	40,831	72,883	51,056
Performance Units Voluntarily Deferred into the Incentive Compensation Deferral Program	39,526	39,691	26,337
Performance Units to be Paid in Cash	809,340	636,645	1,019,179

The cash payouts for the years ended December 31, 2014, 2013 and 2012 were as follows:

	Years Ended December 31,		
Performance Units and AEP Career Shares	**2014**	**2013**	**2012**
		(in thousands)	
Cash Payouts for Performance Units	$ 29,263	$ 43,925	$ 44,968
Cash Payouts for AEP Career Share Distributions	4,324	3,675	11,027

Restricted Stock Units

The HR Committee grants restricted stock units (RSUs), which generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments. Additional RSUs granted as dividends vest on the same date as the underlying RSUs on which the dividends were awarded. Upon vesting, RSUs are converted into a share of AEP common stock, with the exception of participants subject to the disclosure requirements set forth in Section 16 of the Securities Exchange Act of 1934, who are paid in cash. In 2014, there were no RSUs granted to Section 16 participants as AEP deferred granting these and other awards until February 2015. For awards that are settled with shares, compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of units granted by the grant date market closing price. For awards that are paid in cash, compensation cost is recorded over the vesting period and adjusted for changes in fair value until vested. The fair value at vesting is determined by multiplying the number of units vested by the 20-day average closing price of AEP common stock. The maximum contractual term of outstanding RSUs is six years from the grant date.

In 2010, the HR Committee granted a total of 165,520 RSUs to four Chief Executive Officer succession candidates as a retention incentive for these candidates. These grants vest, subject to the candidates' continuous employment, in three approximately equal installments on August 3, 2013, August 3, 2014 and August 3, 2015. Of these RSUs, 55,172 vested on August 3, 2013, 55,172 vested on August 3, 2014 and 55,176 remain outstanding, excluding dividends.

The HR Committee awarded RSUs, including units awarded for dividends, for the years ended December 31, 2014, 2013 and 2012 as follows:

	Years Ended December 31,		
Restricted Stock Units	**2014**	**2013**	**2012**
Awarded Units (in thousands)	64	644	497
Weighted Average Grant Date Fair Value	$ 50.36	$ 46.24	$ 40.69

The total fair value and total intrinsic value of restricted stock units vested during the years ended December 31, 2014, 2013 and 2012 were as follows:

	Years Ended December 31,		
Restricted Stock Units	**2014**	**2013**	**2012**
		(in thousands)	
Fair Value of Restricted Stock Units Vested	$ 18,654	$ 15,325	$ 10,608
Intrinsic Value of Restricted Stock Units Vested (a)	24,894	20,378	12,157

(a) Intrinsic value is calculated as market price at exercise date.

A summary of the status of our nonvested RSUs as of December 31, 2014 and changes during the year ended December 31, 2014 are as follows:

Nonvested Restricted Stock Units	**Shares/Units**	**Weighted Average Grant Date Fair Value**
	(in thousands)	
Nonvested as of January 1, 2014	1,205	$ 42.64
Granted	64	50.36
Vested	(467)	39.97
Forfeited	(19)	44.57
Nonvested as of December 31, 2014	783	44.59

The total aggregate intrinsic value of nonvested RSUs as of December 31, 2014 was $48 million and the weighted average remaining contractual life was 1.61 years.

Other Stock-Based Plans

We also have a Stock Unit Accumulation Plan for Non-employee Directors providing each non-employee director with AEP stock units as a substantial portion of their quarterly compensation for their services as a director. The number of stock units provided is based on the closing price of AEP common stock on the last trading day of the quarter for which the stock units were earned. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The stock units granted to Non-employee Directors are fully vested upon grant date. Stock units are paid in cash upon termination of board service or up to 10 years later if the participant so elects. Cash payments for stock units are calculated based on the average closing price of AEP common stock for the last 20 trading days prior to the distribution date.

We record compensation cost for stock units when the units are awarded and adjust the liability for changes in value based on the current 20-day average closing price of AEP common stock on the valuation date.

The cash payout for stock unit distributions was $5 million for the year ended December 31, 2014. We had no material cash payouts for stock unit distributions for the years ended December 31, 2013 and 2012.

The Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2014, 2013 and 2012 as follows:

	Years Ended December 31,		
Stock Unit Accumulation Plan for Non-Employee Directors	**2014**	**2013**	**2012**
Awarded Units (in thousands)	25	33	52
Weighted Average Grant Date Fair Value	$ 54.08	$ 45.81	$ 41.20

Share-based Compensation Plans

Compensation cost and the actual tax benefit realized for the tax deductions from compensation cost for share-based payment arrangements recognized in income and total compensation cost capitalized in relation to the cost of an asset for the years ended December 31, 2014, 2013 and 2012 were as follows:

	Years Ended December 31,		
Share-based Compensation Plans	**2014**	**2013**	**2012**
		(in thousands)	
Compensation Cost for Share-based Payment Arrangements (a)	$ 85,414	$ 56,352	$ 51,767
Actual Tax Benefit Realized	29,895	19,723	18,119
Total Compensation Cost Capitalized	23,063	13,165	10,707

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance expenses on the statements of income.

During the years ended December 31, 2014, 2013 and 2012, there were no significant modifications affecting any of our share-based payment arrangements.

As of December 31, 2014, there was $79 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the LTIP. Unrecognized compensation cost related to the performance units and AEP Career Shares will change as the fair value is adjusted each period and forfeitures for all award types are realized. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.35 years.

Cash received from stock options exercised and actual tax benefit realized for the tax deductions from stock options exercised during the years ended December 31, 2014, 2013 and 2012 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2014	2013	2012
		(in thousands)	
Cash Received from Stock Options Exercised	$ —	$ 5,659	$ 3,598
Actual Tax Benefit Realized for the Tax Deductions from Stock Options Exercised	—	1,040	618

Our practice is to use authorized but unissued shares to fulfill share commitments for stock option exercises and RSU vesting. Although we do not currently anticipate any changes to this practice, we are permitted to use treasury shares, shares acquired in the open market specifically for distribution under the LTIP or any combination thereof for this purpose. The number of new shares issued to fulfill vesting RSUs is generally reduced to offset our tax withholding obligation.

16. VARIABLE INTEREST ENTITIES

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether we are the primary beneficiary of a VIE, we consider factors such as equity at risk, the amount of the VIE's variability we absorb, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. We believe that significant assumptions and judgments were applied consistently.

We are the primary beneficiary of Sabine, DCC Fuel, AEP Credit, Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, a protected cell of EIS and Transource Energy. In addition, we have not provided material financial or other support to any of these entities that was not previously contractually required. We hold a significant variable interest in DHLC and Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series).

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the years ended December 31, 2014, 2013 and 2012 were $151 million, $155 million and $147 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on the balance sheets.

I&M has nuclear fuel lease agreements with DCC Fuel IV LLC, DCC Fuel V LLC, DCC Fuel VI LLC and DCC Fuel VII (collectively DCC Fuel). DCC Fuel was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the years ended December 31, 2014, 2013 and 2012 were $109 million, $153 million and $127 million, respectively. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the respective lease terms, which do not exceed 54 months. Based on our control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. The lease agreements ended for DCC Fuel LLC and DCC Fuel III LLC in October 2013 and for DCC Fuel II LLC in October 2014. See the tables below for the classification of DCC Fuel's assets and liabilities on the balance sheets.

AEP Credit is a wholly-owned subsidiary of AEP. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides a minimum of 5% equity and up to 20% of AEP Credit's short-term borrowing needs in excess of third party financings. Any third party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on our control of AEP Credit, management concluded that we are the primary beneficiary and are required to consolidate AEP Credit. See the tables below for the classification of AEP Credit's assets and liabilities on the balance sheets. See "Securitized Accounts Receivables – AEP Credit" section of Note 14.

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. Management has concluded that TCC is the primary beneficiary of Transition Funding because TCC has the power to direct the most significant activities of the VIE and TCC's equity interest could potentially be significant. Therefore, TCC is required to consolidate Transition Funding. The securitized bonds totaled $1.8 billion and $2.0 billion as of December 31, 2014 and 2013, respectively. Transition Funding has securitized transition assets of $1.6 billion and $1.9 billion as of December 31, 2014 and 2013, respectively. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from TCC under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to TCC or any other AEP entity. TCC acts as the servicer for Transition Funding's securitized transition assets and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Transition Funding's assets and liabilities on the balance sheets.

Ohio Phase-in-Recovery Funding was formed for the sole purpose of issuing and servicing securitization bonds related to phase-in recovery property. Management has concluded that OPCo is the primary beneficiary of Ohio Phase-in-Recovery Funding because OPCo has the power to direct the most significant activities of the VIE and OPCo's equity interest could potentially be significant. Therefore, OPCo is required to consolidate Ohio Phase-in-Recovery Funding. The securitized bonds totaled $232 million and $267 million as of December 31, 2014 and 2013, respectively. Ohio Phase-in-Recovery Funding has securitized assets of $110 million and $132 million as of December 31, 2014 and 2013, respectively. The phase-in recovery property represents the right to impose and collect Ohio deferred distribution charges from customers receiving electric transmission and distribution service from OPCo under a recovery mechanism approved by the PUCO. In August 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to OPCo or any other AEP entity. OPCo acts as the servicer for Ohio Phase-in-Recovery Funding's securitized assets and remits all related amounts collected from customers to Ohio Phase-in-Recovery Funding for interest and principal payments on the securitization bonds and related costs. See the table below for the classification of Ohio Phase-in-Recovery Funding's assets and liabilities on the balance sheets.

Appalachian Consumer Rate Relief Funding was formed for the sole purpose of issuing and servicing securitization bonds related to APCo's under-recovered ENEC deferral balance. Management has concluded that APCo is the primary beneficiary of Appalachian Consumer Rate Relief Funding because APCo has the power to direct the most significant activities of the VIE and APCo's equity interest could potentially be significant. Therefore, APCo is required to consolidate Appalachian Consumer Rate Relief Funding. The securitized bonds totaled $368 million and $380 million as of December 31, 2014 and 2013, respectively. Appalachian Consumer Rate Relief Funding has securitized assets of $350 million and $369 million as of December 31, 2014 and 2013, respectively. The phase-in recovery property represents the right to impose and collect West Virginia deferred generation charges from customers receiving electric transmission, distribution and generation service from APCo under a recovery mechanism approved by the WVPSC. In November 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to APCo or any other AEP entity. APCo acts as the servicer for Appalachian Consumer Rate Relief Funding's securitized assets and remits all related amounts collected from customers to Appalachian Consumer Rate Relief Funding for interest and principal payments on the securitization bonds and related costs. See the table below for the classification of Appalachian Consumer Rate Relief Funding's assets and liabilities on the balance sheets.

The securitized bonds of Transition Funding, Ohio Phase-in-Recovery Funding and Appalachian Consumer Rate Relief Funding are included in current and long-term debt on the balance sheets. The securitized assets of Transition Funding, Ohio Phase-in-Recovery Funding and Appalachian Consumer Rate Relief Funding are included in securitized assets on the balance sheets.

Our subsidiaries participate in one protected cell of EIS for approximately ten lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. Our subsidiaries and any allowed

third parties share in the insurance coverage, premiums and risk of loss from claims. Based on our control and the structure of the protected cell of EIS, management concluded that we are the primary beneficiary of the protected cell and are required to consolidate the protected cell of EIS. Our insurance premium expense to the protected cell for the years ended December 31, 2014, 2013 and 2012 were $32 million, $31 million and $32 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on the balance sheets.

Transource Energy was formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates. AEP has equity and voting ownership of 86.5% with the other owner having 13.5% interest. Management has concluded that Transource Energy is a VIE and that AEP is the primary beneficiary because AEP has the power to direct the most significant activities of the entity. Therefore, AEP is required to consolidate Transource Energy. AEP's equity interest could potentially be significant. In January 2014, Transource Missouri (a wholly-owned subsidiary of Transource Energy) acquired transmission assets from the non-controlling owner and issued debt and received a capital contribution to fund the acquisition. The majority of Transource Energy's activity resulted from the asset acquisition, construction projects, debt issuance and capital contribution. AEP has provided capital contributions to Transource Energy of $23 million and $3 million, in 2014 and 2013, respectively. In the event a Transource Missouri project is abandoned by the RTO, AEP would be required to fund additional capital. See the tables below for the classification of Transource Energy's assets and liabilities on the balance sheets.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2014
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	AEP Credit	TCC Transition Funding	OPCo Ohio Phase-in-Recovery Funding	APCo Appalachian Consumer Rate Relief Funding	Protected Cell of EIS	Transource Energy
ASSETS								
Current Assets	$ 68	$ 97	$ 980	$ 239	$ 33	$ 18	$ 149	$ 2
Net Property, Plant and Equipment	145	158	—	—	—	—	—	98
Other Noncurrent Assets	52	80	—	1,654 (a)	210 (b)	358 (c)	2	4
Total Assets	$ 265	$ 335	$ 980	$ 1,893	$ 243	$ 376	$ 151	$ 104
LIABILITIES AND EQUITY								
Current Liabilities	$ 36	$ 86	$ 894	$ 322	$ 47	$ 27	$ 44	$ 21
Noncurrent Liabilities	228	249	—	1,553	195	347	62	55
Equity	1	—	86	18	1	2	45	28
Total Liabilities and Equity	$ 265	$ 335	$ 980	$ 1,893	$ 243	$ 376	$ 151	$ 104

(a) Includes an intercompany item eliminated in consolidation of $75 million.
(b) Includes an intercompany item eliminated in consolidation of $97 million.
(c) Includes an intercompany item eliminated in consolidation of $4 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2013
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	AEP Credit	TCC Transition Funding	OPCo Ohio Phase-in-Recovery Funding	APCo Appalachian Consumer Rate Relief	Protected Cell of EIS
ASSETS							
Current Assets	$ 67	$ 118	$ 935	$ 232	$ 23	$ 6	$ 143
Net Property, Plant and Equipment	157	157	—	—	—	—	—
Other Noncurrent Assets	51	60	1	1,918 (a)	252 (b)	378 (c)	3
Total Assets	$ 275	$ 335	$ 936	$ 2,150	$ 275	$ 384	$ 146
LIABILITIES AND EQUITY							
Current Liabilities	$ 33	$ 108	$ 827	$ 312	$ 37	$ 14	$ 39
Noncurrent Liabilities	242	227	1	1,820	237	368	66
Equity	—	—	108	18	1	2	41
Total Liabilities and Equity	$ 275	$ 335	$ 936	$ 2,150	$ 275	$ 384	$ 146

(a) Includes an intercompany item eliminated in consolidation of $82 million.
(b) Includes an intercompany item eliminated in consolidation of $116 million.
(c) Includes an intercompany item eliminated in consolidation of $4 million.

DHLC is a mining operator that sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and voting rights equally. Each entity guarantees 50% of DHLC's debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. SWEPCo's total billings from DHLC for the years ended December 31, 2014, 2013 and 2012 were $56 million, $60 million and $77 million, respectively. We are not required to consolidate DHLC as we are not the primary beneficiary, although we hold a significant variable interest in DHLC. Our equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on the balance sheets.

Our investment in DHLC was:

	2014		2013	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from SWEPCo	$ 8	$ 8	$ 8	$ 8
Retained Earnings	4	4	1	1
Advance Due to Parent	56	56	—	—
Guarantee of Debt	—	48	—	61
Total Investment in DHLC	$ 68	$ 116	$ 9	$ 70

We and FirstEnergy Corp. (FirstEnergy) have a joint venture in Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct, through its operating companies, a high-voltage transmission line project in the PJM region. PATH consists of the "West Virginia Series (PATH-WV)," owned equally by subsidiaries of FirstEnergy and AEP, and the "Allegheny Series" which is 100% owned by a subsidiary of FirstEnergy. Provisions exist within the PATH-WV agreement that make it a VIE. The "Allegheny Series" is not considered a VIE. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant variable interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the balance sheets. We and FirstEnergy share the returns and losses equally in PATH-WV. Our subsidiaries and FirstEnergy's subsidiaries provide services to the PATH companies through service agreements. The entities recover costs through regulated rates.

In August 2012, the PJM board cancelled the PATH Project, the transmission project that PATH was intended to develop, 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 PATH 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 parties to the case have been unable to reach a settlement agreement and in March 2014, settlement judge procedures were terminated. Litigation is ongoing and a hearing at the FERC is scheduled for March 2015.

Our investment in PATH-WV was:

	December 31,			
	2014		2013	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$ 19	$ 19	$ 19	$ 19
Retained Earnings	2	2	6	6
Total Investment in PATH-WV	$ 21	$ 21	$ 25	$ 25

As of December 31, 2014, our $21 million investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the balance sheet. If we cannot ultimately recover our investment related to PATH-WV, it could reduce future net income and cash flows.

17. PROPERTY, PLANT AND EQUIPMENT

Depreciation, Depletion and Amortization

We provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following tables provide the annual property information:

2014	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(in millions)			(in years)	(in millions)			(in years)
Generation	$ 18,394	$ 7,313	1.7 - 3.5%	31 - 132	$ 7,333	$ 3,135	2.6 - 3.4%	35 - 66
Transmission	12,395	2,877	1.4 - 2.7%	15 - 87	38	17	2.3%	43 - 55
Distribution	17,157	4,145	2.4 - 3.7%	7 - 75	—	—	NA	NA
CWIP	3,088	(126)	NM	NM	130	1	NM	NM
Other	4,361	2,254	2.1 - 8.6%	5 - 75	1,409	572	17.1%	25 - 50
Total	$ 55,395	$ 16,463			$ 8,910	$ 3,725		

2013	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(in millions)			(in years)	(in millions)			(in years)
Generation	$ 17,873	$ 7,168	1.7 - 3.7%	31 - 132	$ 7,201	$ 2,969	2.6 - 3.3%	35 - 66
Transmission	10,854	2,805	1.1 - 2.7%	25 - 87	39	16	2.5%	43 - 55
Distribution	16,377	3,988	2.3 - 3.8%	11 - 75	—	—	NA	NA
CWIP	2,326	(121)	NM	NM	145	1	NM	NM
Other	4,116	1,931	2.0 - 7.9%	5 - 75	1,354	531	NM	NM
Total	$ 51,546	$ 15,771			$ 8,739	$ 3,517		

2012	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
		(in years)		(in years)
Generation	1.7 - 3.8%	31 - 132	2.6 - 3.3%	35 - 66
Transmission	1.2 - 2.8%	25 - 87	NA	NA
Distribution	2.4 - 3.9%	11 - 75	NA	NA
CWIP	NM	NM	NM	NM
Other	1.8 - 9.6%	5 - 75	NM	NM

NA Not applicable.
NM Not meaningful.

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense.

For regulated operations, the composite depreciation rate generally includes a component for non-asset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

Asset Retirement Obligations (ARO)

We record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for our legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, closure and monitoring of underground carbon storage facilities at Mountaineer Plant, wind farms and certain coal mining facilities, as well as for nuclear decommissioning of our Cook Plant. We have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. We do not estimate the retirement for such easements because we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements, which is not expected.

The following is a reconciliation of the 2014 and 2013 aggregate carrying amounts of ARO:

	Carrying Amount of ARO
	(in millions)
ARO as of December 31, 2012	$ 1,696
Accretion Expense	103
Liabilities Incurred	4
Liabilities Settled	(22)
Revisions in Cash Flow Estimates	54
ARO as of December 31, 2013	1,835
Accretion Expense	95
Liabilities Incurred	42
Liabilities Settled	(34)
Revisions in Cash Flow Estimates	81
ARO as of December 31, 2014	$ 2,019

As of December 31, 2014 and 2013, our ARO liability included $1.3 billion and $1.2 billion, respectively, for nuclear decommissioning of the Cook Plant. As of December 31, 2014 and 2013, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $1.8 billion and $1.6 billion, respectively, and are recorded in Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

Our amounts of allowance for borrowed, including interest capitalized, and equity funds used during construction is summarized in the following table:

	Years Ended December 31,		
	2014	2013	2012
		(in millions)	
Allowance for Equity Funds Used During Construction	$ 103	$ 73	$ 93
Allowance for Borrowed Funds Used During Construction	44	40	69

Jointly-owned Electric Facilities

We have electric facilities that are jointly-owned with nonaffiliated companies. Using our own financing, we are obligated to pay a share of the costs of these jointly-owned facilities in the same proportion as our ownership interest. Our proportionate share of the operating costs associated with such facilities is included on the statements of income and the investments and accumulated depreciation are reflected on the balance sheets under Property, Plant and Equipment as follows:

			Company's Share as of December 31, 2014		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station, Unit 6 (a)	Coal	12.5%	$ —	$ —	$ —
Conesville Generating Station, Unit 4 (b)	Coal	43.5%	336	2	66
J.M. Stuart Generating Station (c)	Coal	26.0%	553	12	206
Wm. H. Zimmer Generating Station (a)	Coal	25.4%	812	4	410
Dolet Hills Generating Station, Unit 1 (d)	Lignite	40.2%	330	4	201
Flint Creek Generating Station, Unit 1 (e)	Coal	50.0%	125	120	68
Pirkey Generating Station, Unit 1 (e)	Lignite	85.9%	531	36	381
Oklaunion Generating Station, Unit 1 (f)	Coal	70.3%	409	10	228
Turk Generating Plant (e)	Coal	73.33%	1,647	1	70
Transmission	NA	(g)	82	1	49
Total			$ 4,825	$ 190	$ 1,679

			Company's Share as of December 31, 2013		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station, Unit 6 (a)	Coal	12.5%	$ —	$ —	$ —
Conesville Generating Station, Unit 4 (b)	Coal	43.5%	335	2	55
J.M. Stuart Generating Station (c)	Coal	26.0%	544	11	190
Wm. H. Zimmer Generating Station (a)	Coal	25.4%	809	2	399
Dolet Hills Generating Station, Unit 1 (d)	Lignite	40.2%	262	47	198
Flint Creek Generating Station, Unit 1 (e)	Coal	50.0%	123	54	66
Pirkey Generating Station, Unit 1 (e)	Lignite	85.9%	519	29	376
Oklaunion Generating Station, Unit 1 (f)	Coal	70.3%	404	7	223
Turk Generating Plant (e)	Coal	73.33%	1,638	13	35
Transmission	NA	(g)	78	—	50
Total			$ 4,712	$ 165	$ 1,592

(a) Operated by Duke Energy Corporation, a nonaffiliated company. AEP's portion of Beckjord Plant, Unit 6 was impaired in the fourth quarter of 2012. See "Impairments" section of Note 7.
(b) Operated by AGR.
(c) Operated by The Dayton Power & Light Company, a nonaffiliated company.
(d) Operated by CLECO, a nonaffiliated company.
(e) Operated by SWEPCo.
(f) Operated by PSO and also jointly-owned (54.7%) by TNC.
(g) Varying percentages of ownership.
NA Not applicable.

18. COST REDUCTION PROGRAMS

2014 Disposition Plant Severance

AEP intends to retire several generation plants or units of plants during 2015. The plant closures will result in involuntary severances. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

We recorded a charge to Other Operation expense in December 2014 primarily related to employees at the disposition plants.

	Disposition Plant Severance Activity
	(in millions)
Incurred	$ 29
Settled	—
Adjustments	—
Balance as of December 31, 2014	$ 29

These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the statements of income. Of the current period expense, approximately 32% was within the Generation & Marketing segment and 68% was within the Vertically Integrated Utilities segment. The remaining liability is included in Other Current Liabilities on the balance sheets. We do not expect additional severance costs to be incurred related to this initiative.

2012 Sustainable Cost Reductions

In April 2012, we initiated a process to identify strategic repositioning opportunities and efficiencies that will result in sustainable cost savings. We selected a consulting firm to facilitate an organizational and process evaluation and a second firm to evaluate our current employee benefit programs. The process resulted in involuntary severances and was completed by the end of the first quarter of 2013. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

We recorded charges to Other Operation expense of $7 million and $47 million for the years ended December 31, 2013 and 2012, respectively, primarily related to severance benefits as a result of the sustainable cost reductions initiative.

19. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In our opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of our results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. Our unaudited quarterly financial information is as follows:

	2014 Quarterly Periods Ended				
	March 31	June 30	September 30	December 31	
	(in millions – except per share amounts)				
Total Revenues	$ 4,648	$ 4,044	$ 4,302	$ 4,026	
Operating Income	1,041	767	925	499	(a)
Net Income	561	391	494	192	(a)
Earnings Attributable to AEP Common Shareholders	560	390	493	191	
Total Basic Earnings per Share Attributable to AEP Common Shareholders (b)	1.15	0.80	1.01	0.39	
Total Diluted Earnings per Share Attributable to AEP Common Shareholders (b)	1.15	0.80	1.01	0.39	

	2013 Quarterly Periods Ended				
	March 31	June 30	September 30	December 31	
	(in millions – except per share amounts)				
Total Revenues	$ 3,826	$ 3,582	$ 4,176	$ 3,773	
Operating Income	755	547 (c)	875 (e)	678	(f)(g)
Net Income	364	339 (c)(d)	434 (e)	347	(f)(g)
Earnings Attributable to AEP Common Shareholders	363	338 (c)(d)	433 (e)	346	(f)(g)
Total Basic Earnings per Share Attributable to AEP Common Shareholders (b)	0.75	0.69	0.89	0.71	
Total Diluted Earnings per Share Attributable to AEP Common Shareholders (b)	0.75	0.69	0.89	0.71	

(a) Includes termination of a coal contract and a KPCo regulatory disallowance (see Note 4).
(b) Quarterly Earnings per Share amounts are intended to be stand-alone calculations and are not always additive to full-year amount due to rounding.
(c) Includes an impairment for Muskingum River Plant, Unit 5 (see Note 7).
(d) Includes U.K. Windfall Tax benefit (see Note 12).
(e) Includes regulatory disallowances for the Turk Plant (see Note 4) and for Big Sandy Plant, Unit 2 (see Note 7).
(f) Includes a regulatory disallowance for Amos Plant, Unit 3 (see Note 7).
(g) Includes the reversal of regulatory disallowance for the Turk Plant (see Note 4).

20. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2014 and 2013 by operating segment are as follows:

	Vertically Integrated Utilities	AEP River Operations	Generation and Marketing	AEP Consolidated
			(in millions)	
Balance as of December 31, 2012	$ 37	$ 39	$ 15	$ 91
Impairment Losses	—	—	—	—
Balance as of December 31, 2013	37	39	15	91
Impairment Losses	—	—	—	—
Balance as of December 31, 2014	$ 37	$ 39	$ 15	$ 91

In the fourth quarters of 2014 and 2013, we performed our annual impairment tests. The fair values of the operations with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses. We do not have any accumulated impairment on existing goodwill.

Other Intangible Assets

Acquired intangible assets subject to amortization were $5 million and $10 million as of December 31, 2014 and 2013, respectively, net of accumulated amortization and are included in Deferred Charges and Other Noncurrent Assets on the balance sheets. The amortization life, gross carrying amount and accumulated amortization by major asset class are as follows:

		December 31,			
		2014		2013	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)	(in millions)			
Acquired Customer Contracts	5	$ 58	$ 53	$ 58	$ 48

Amortization of intangible assets was $5 million, $14 million and $34 million for the years ended December 31, 2014, 2013 and 2012, respectively. Our estimated total amortization is $3 million and $2 million for 2015 and 2016, respectively.

CORPORATE AND SHAREHOLDER INFORMATION

Corporate Headquarters
1 Riverside Plaza
Columbus, OH 43215-2373
614-716-1000
AEP is incorporated in the State of New York.

Stock Exchange Listing – The Company's common stock is traded principally on the New York Stock Exchange under the ticker symbol AEP.

Internet Home Page – Information about AEP, including financial documents, Securities and Exchange Commission (SEC) filings, news releases, investor presentations, shareholder information and customer service information, is available on the Company's home page on the Internet at www.AEP.com/investors.

Inquiries Regarding Your Stock Holdings – Registered shareholders (shares that you own, in your name) should contact the Company's transfer agent, listed below, if you have questions about your account, address changes, stock transfer, lost certificates, direct deposits, dividend checks and other administrative matters. You should have your Social Security number or account number ready; the transfer agent will not speak to third parties about an account without the shareholder's approval or appropriate documents.

Transfer Agent & Registrar
Computershare Trust Company, N.A.
P.O. Box 43078
Providence, RI 02940-3078
For overnight deliveries:
Computershare Trust Company, N.A.
250 Royall Street
Canton, MA 02021-1011
Telephone Response Group:1-800-328-6955
Internet address: www.computershare.com/investor
Hearing Impaired #: TDD: 1-800-952-9245

Beneficial Holders – (Stock held in a bank or brokerage account) – When you purchase stock and it is held for you by your broker, it is listed with the Company in the broker's name, and this is sometimes referred to as "street name" or a "beneficial owner." AEP does not know the identity of individual shareholders who hold their shares in this manner; we simply know that a broker holds a certain number of shares which may be for any number of customers. If you hold your stock in street name, you receive all dividend payments, annual reports and proxy materials through your broker. Therefore, questions about your account should be directed to your broker.

Dividend Reinvestment and Direct Stock Purchase Plan – A Dividend Reinvestment and Direct Stock Purchase Plan is available to all investors. It is an economical and convenient method of purchasing shares of AEP common stock, through initial cash investments, cash dividends and/or additional optional cash purchases. You may obtain the Plan prospectus and enrollment authorization form by contacting the transfer agent or by visiting www.AEP.com/investors/buyandmanagestock.

Financial Community Inquiries – Institutional investors or securities analysts who have questions about the Company should direct inquiries to Bette Jo Rozsa, 614-716-2840, bjrozsa@AEP.com; Individual shareholders should contact Kathleen Kozero, 614-716-2819, klkozero@AEP.com.

Number of Shareholders – As of February 23, 2015, there were approximately 73,000 registered shareholders and approximately 500,000 shareholders holding stock in street name through a bank or broker. There were 489,620,548 shares outstanding as of February 23, 2015.

Form 10-K – Upon request, we will provide without charge a copy of our Form 10-K for the fiscal year ended December 31, 2014. A copy can be obtained via mail with a written request to AEP Investor Relations, by telephone at 1-800-237-2667 or electronically at klkozero@AEP.com.

Executive Leadership Team

Name	Age	Office
Nicholas K. Akins	54	Chairman of the Board, President and Chief Executive Officer
Lisa M. Barton	49	Executive Vice President – Transmission
David M. Feinberg	45	Executive Vice President, General Counsel and Secretary
Lana L. Hillebrand	54	Senior Vice President and Chief Administrative Officer
Mark C. McCullough	55	Executive Vice President – Generation
Robert P. Powers	61	Executive Vice President and Chief Operating Officer
Brian X. Tierney	47	Executive Vice President and Chief Financial Officer
Dennis E. Welch	63	Executive Vice President and Chief External Officer
Charles E. Zebula	54	Executive Vice President – Energy Supply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