AMERICAN ELECTRIC POWER CO INC
Form 10-Q
April 25, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended March 31, 2014
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ____ to ____

Commission File Number	Registrants; States of Incorporation; Address and Telephone Number	I.R.S. Employer Identification Nos.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
	1 Riverside Plaza, Columbus, Ohio 43215-2373	
	Telephone (614) 716-1000	

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Yes X No

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate websites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).

Yes X No

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

X Accelerated filer

Large accelerated filer			
Non-accelerated filer		Smaller reporting company	

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

Large accelerated filer		Accelerated filer	
Non-accelerated filer	X	Smaller reporting company	

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act).

Yes		No	X

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

	Number of shares of common stock outstanding of the registrants as of April 23, 2014
American Electric Power Company, Inc.	488,083,018
	($6.50 par value)
Appalachian Power Company	13,499,500
	(no par value)
Indiana Michigan Power Company	1,400,000
	(no par value)
Ohio Power Company	27,952,473
	(no par value)
Public Service Company of Oklahoma	9,013,000
	($15 par value)
Southwestern Electric Power Company	7,536,640
	($18 par value)

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF QUARTERLY REPORTS ON FORM 10-Q
March 31, 2014

Part II. OTHER INFORMATION

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

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. BlueStar began doing business as AEP Energy, Inc. in June 2012.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AGR	AEP Generation Resources Inc., a nonregulated AEP subsidiary in the Generation & Marketing segment.
AFUDC	Allowance for Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
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.
CO2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CRES provider	Competitive Retail Electric Service providers under Ohio law that target retail customers by offering alternative generation service.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.

CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, DCC Fuel IV LLC, DCC Fuel V LLC and DCC Fuel VI LLC, 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.
ERCOT	Electric Reliability Council of Texas regional transmission organization.

Term	Meaning
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP and MidAmerican Energy Holdings Company Texas Transco, LLC formed to own and operate electric transmission facilities in ERCOT.
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.
KWh	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NOx	Nitrogen oxide.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NSR	New Source Review.
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.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
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.

Term	Meaning
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, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SNF	Spent Nuclear Fuel.
SO2	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.
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" of the 2013 Annual Report, 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 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 retail competition, particularly in Ohio.
- 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.
- Changes in utility regulation and the allocation of costs within regional transmission organizations, including PJM and SPP.

- The transition to market for generation in Ohio, including the implementation of ESPs.
- 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 the 2013 Annual Report and in Part II of this report.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Ohio Electric Security Plan Filing

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. As of March 31, 2014, OPCo's net deferred fuel balance was $426 million, excluding unrecognized equity carrying costs. Decisions from the Supreme Court of Ohio are pending related to various appeals which, if ordered, could reduce OPCo's net deferred fuel costs balance.

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, which includes reserve margins, is approximately $33/MW day through May 2014 and $148/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 is being collected from customers at $3.50/MWh through May 2014 and will be 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 March 31, 2014, OPCo's incurred deferred capacity costs balance was $348 million, including debt carrying costs.

In November 2013, the PUCO issued an order approving OPCo's competitive bid process with modifications. The modifications include the delay of the energy auctions that were originally ordered in the ESP order. In February 2014, OPCo conducted an energy-only auction for 10% of the SSO load with delivery beginning April 2014 through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 50% of the SSO load with delivery beginning November 2014 through May 2015 and for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. OPCo will conduct energy and capacity auctions for its entire SSO load for delivery starting in June 2015. 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.

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. This filing is consistent with the PUCO's objective for a full transition from FAC and base generation rates to market. The proposal includes a recommended auction schedule, 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 and energy auction-based generation through OPCo. Additionally, the

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application identifies OPCo's intention to submit a separate application to continue the RSR established in the June 2012 – May 2015 ESP in which the unrecovered portion of the deferred capacity costs will continue to be collected at the rate of $4.00/MWh until the balance of the capacity deferrals has been collected. Management intends to file this application in the second quarter of 2014. A hearing at the PUCO in the ESP case is scheduled for June 2014.

If OPCo is ultimately not permitted to fully collect its ESP rates, including the RSR, its deferred fuel balance and its deferred capacity cost, it could reduce future net income and cash flows and impact financial condition. See "Ohio Electric Security Plan Filing" section of Note 4.

Ohio Customer Choice

In our Ohio service territory, various CRES providers are targeting retail customers by offering alternative generation service. The reduction in gross margin as a result of customer switching in Ohio is partially offset by (a) collection of capacity revenues from CRES providers, (b) wholesale sales, (c) deferral of unrecovered capacity costs, (d) RSR collections and (e) revenues from AEP Energy. AEP Energy is our CRES provider and part of our Generation & Marketing segment which targets retail customers, both within and outside of our retail service territory.

Customer Demand

In comparison to 2013, heating degree days in 2014 were up 40% in our western region and 24% in our eastern region. Our weather-normalized retail sales volumes for the first quarter of 2014 increased by 1.5% from their levels for the first quarter of 2013. First quarter 2014 weather-adjusted residential and commercial customer sales were up 4.4% and 2.9%, respectively, from their levels for the first quarter of 2013. Residential and commercial customer counts grew 0.4% and 0.8% in the first quarter of 2014, respectively, from the first quarter of 2013.

Our industrial sales volumes in the first quarter 2014 decreased 2.9% from the first quarter of 2013 due mainly to the closure of Ormet, a large aluminum company. Ormet had a contract to purchase power from OPCo through 2018. In October 2013, Ormet announced that it was unable to emerge from bankruptcy and shut down its operations effective immediately. Excluding Ormet, our first quarter 2014 industrial sales volumes increased 2.2% over the first quarter of 2013. The loss of Ormet's load will not have a material impact on future gross margin because power previously sold to Ormet will be available for sale into generally higher priced wholesale markets.

PJM Capacity Market

Through May 2015, AGR will provide generation capacity to OPCo for both switched and non-switched OPCo generation customers. AGR is required to offer all of its remaining generation capacity in the PJM RPM auction, which is conducted three years in advance of the actual delivery year. AGR generation assets are subject to PJM capacity prices for periods after May 2015. For switched customers, OPCo pays AGR $188.88/MW day. For non-switched OPCo generation customers, OPCo pays AGR for capacity. AGR's non-OPCo load is subject to the PJM RPM auction. 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		125.99

2015	
June 2015 through May 2016	136.00
June 2016 through May 2017	59.37

Due to the volatility and uncertainty in prices, we formed a coalition with other utility companies to address mutual concerns related to the PJM capacity auction process, including: (a) import limits for power without firm transmission, (b) placing bidding caps on available demand response resources in comparison to base generation capacity, (c) modification and enforcement of the timing of demand response requirements to better reflect real-time capacity requirements and (d) tightened rules for incremental auctions in which speculative bidders currently can sell resources in the base auction and buy back that capacity in an incremental auction, resulting in no additional capacity and lower auction prices. PJM has made four FERC filings related to those issues. In January 2014, FERC

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accepted without modification PJM's filed recommendations on placing bidding caps on certain demand response products that are available only during the summer period. We expect to receive FERC decisions on the other filings prior to the next RPM auction in May 2014.

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 May 2013, SWEPCo filed testimony in the prudence review of the Turk Plant. If the LPSC orders refunds based upon the pending staff review of the cost of service or the prudence review of the Turk Plant, it could reduce future net income and cash flows and impact financial condition. See the “2012 Louisiana Formula Rate Filing” section of Note 4.

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 March 31, 2014, SWEPCo has incurred $48 million in costs related to these projects. SWEPCo will seek to recover these project costs from its state commissions and FERC customers.

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 2014, the OCC Staff and intervenors filed testimony with various recommendations. A hearing at the OCC is scheduled for June 2014. See the "2014 Oklahoma Base Rate Case" section of Note 4.

2014 Virginia Biennial Base Rate Case

In March 2014, APCo filed a generation and distribution base rate biennial review 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 is 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 certain deferred costs. If any of these costs 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.

Cook Plant Life Cycle Management Project (LCM Project)

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, 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 March 31, 2014, I&M has incurred costs of $405 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 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 December 2013, the IURC issued an interim order authorizing the implementation of LCM rider rates effective January 2014, subject to reconciliation upon the issuance of a final order by the IURC.

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.

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. See "Cook Plant Life Cycle Management Project (LCM Project)" section of Note 4.

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, Note 6 – Commitments, Guarantees and Contingencies and the "Litigation" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2013 Annual Report. Additionally, see Note 4 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies included herein. 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 granted our motion to transfer this case to the U.S. District Court for the Southern District of Ohio. Our motion to dismiss the case, filed in October 2013, 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.

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 SO2, NOx, PM and hazardous air pollutants (HAPs) from fossil fuel-fired power plants, proposals governing the beneficial use and disposal of coal combustion products and proposed clean water rules.

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 possible 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.

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See a complete discussion of these matters in the "Environmental Issues" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2013 Annual Report. 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 March 31, 2014, the AEP System had a total generating capacity of 37,600 MWs, of which 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, investment to meet these proposed requirements ranges from approximately $3 billion to $3.5 billion through 2020. These amounts include investments to convert some of our coal generation to natural gas. If natural gas conversion is not completed, the 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 or federal implementation plans 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)
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
APCo/AGR	Sporn Plant, Units 1-4	600
I&M	Tanners Creek Plant, Units 1-4	995
KPCo	Big Sandy Plant, Unit 2	800
AGR	Kammer Plant	630
AGR	Muskingum River Plant, Units 1-5	1,440
AGR	Picway Plant	100
PSO	Northeastern Station, Unit 4	470
SWEPCo	Welsh Plant, Unit 2	528
Total		6,533

As of March 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 $974 million.

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In addition, we are in the process of obtaining permits and other necessary regulatory approvals for either the conversion of some of our coal units to natural gas or installing emission control equipment on certain units. The following table lists the unit that is either awaiting regulatory approval or are still being evaluated by management based on changes in emission requirements and demand for power:

Company	Plant Name and Unit	Generating Capacity (in MWs)
KPCo	Big Sandy Plant, Unit 1	278

As of March 31, 2014, the net book value before cost of removal, including related material and supplies inventory and CWIP balances, of the unit in the table above was $88 million.

PSO received Federal EPA approval of the Oklahoma SIP, in February 2014, related to the environmental compliance plan for Northeastern Station, Unit 3.

Volatility in natural gas 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 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.

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 SO2 and NOx emissions from power plants. In 2008, the District of Columbia Circuit Court of Appeals issued a decision remanding CAIR to the Federal EPA. The Federal EPA issued the Cross-State Air Pollution Rule (CSAPR) (discussed in detail below) in August 2011 to replace CAIR. The CSAPR was challenged in the courts. The U.S. Court of Appeals for the District of Columbia Circuit issued an order in 2011 staying the effective date of the rule pending judicial review. 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 has been appealed to the U.S. Supreme Court. Nearly all of the states in which our power plants are located are covered by CAIR.

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 individual state implementation plans (SIPs) or, if SIPs are not adequate or are not developed on schedule, through federal implementation plans (FIPs). The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas. The Arkansas SIP was disapproved and the state 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 SO2 and NOx 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 and its fate is uncertain given developments in the CSAPR litigation.

In 2009, the Federal EPA issued a final mandatory reporting rule for CO2 and other greenhouse gases covering a broad range of facilities emitting in excess of 25,000 tons of CO2 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 CO2 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 CO2 emissions in standards that apply to new electric utility units and will consider whether such standards are appropriate for other source categories in the future.

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for PM, SO2, NOx and lead, and is currently reviewing the 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 SO2 and NOx 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 NOx program in the rule. Texas is subject to the annual programs for SO2 and NOx in addition to the seasonal NOx program. The annual SO2 allowance budgets in Indiana, Ohio and West Virginia were reduced significantly in the rule. A supplemental rule includes Oklahoma in the seasonal NOx program. The supplemental rule was finalized in December 2011 with an increased NOx 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. Several of the petitioners filed motions to stay the implementation of the rule pending judicial review. In 2011, the court granted the motions for stay. 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 Federal EPA and other respondents filed petitions for rehearing but in January 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied all petitions for rehearing. The petition for further review filed by the Federal EPA and other parties in the U.S. Supreme Court was granted in June 2013. Separate appeals of the supplemental rule, the Error Corrections Rule and the further revisions have been filed, but are being held in abeyance.

The time frames and stringency of the required emission reductions, coupled with the lack of robust interstate trading and the elimination of historic allowance banks, pose significant concerns for the AEP System and our electric utility customers. 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 metal) 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. We are participating through various organizations in the petitions for administrative reconsideration and judicial review that have been 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.

The final rule contains a slightly less stringent PM limit for existing sources than the original proposal and allows operators to exclude periods of startup and shutdown from the emissions averaging periods. The compliance time frame remains a serious concern. A one-year administrative extension may be available if the extension is necessary for 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 are concerned about the availability of compliance extensions and the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines. We participated in petitions for review filed in the U.S. Court of Appeals for the District of Columbia Circuit by several organizations of which we are members. Certain issues related to the standards for new coal-fired units have been severed from the main case and are being held in abeyance pending completion of the Federal EPA's reconsideration proceeding. In April 2014, the appellate court issued a decision denying all of the petitions for review of the April 2012 final rule.

CO2 Regulation

In June 2013, 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 in September 2013. The new proposal was issued in September 2013 and requires new large natural gas units to meet 1,000 pounds of CO2 per MWh of electricity generated and small natural gas units to meet 1,100 pounds of CO2 per MWh. New coal-fired units are required to meet the 1,100 pounds of CO2 per MWh limit, with the option to meet the tighter limits if they choose to average emissions over multiple years. This proposal was published in the Federal Register in January 2014.

The Federal EPA was also directed to develop and issue a separate proposal regulating carbon emissions from existing, modified and reconstructed electric generating units 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 President directed the Federal EPA, in developing this proposal, to directly engage states, leaders in the power sector, labor leaders and other stakeholders, to tailor the regulations to reduce costs, to develop market-based instruments and allow regulatory flexibilities and "assure that the standards are developed and implemented in a manner consistent with the continued provision of reliable and affordable electric power." 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 June 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 CO2 emissions from new motor vehicles and its plan to phase in regulation of CO2 emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. A petition for rehearing was filed which the court denied in December 2012. The U.S. Supreme Court granted several petitions for review and will determine whether the Federal EPA made a reasonable determination that adoption of the motor vehicle standards trigger PSD and Title V permitting obligations for stationary sources. A decision is expected by June 2014.

The Federal EPA also finalized a rule in June 2012 that retains the current emission thresholds for permitting stationary sources under the PSD and Title V operating permit programs at 100,000 tons per year for new sources and 75,000 tons per year for modified sources. The Federal EPA also confirmed that it will re-evaluate these thresholds during its five-year review in 2016. Our generating units are large sources of CO_2 emissions and we will continue to evaluate the permitting obligations in light of these thresholds.

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, including fly ash and bottom ash generated at coal-fired electric generating units and also FGD gypsum generated at some coal fired plants. The rule contains 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 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 would require existing unlined surface impoundments to upgrade to the new standards or stop receiving coal ash and initiate closure within five years of the issuance of a final rule. In 2011, the Federal EPA issued a notice of data availability requesting comments on a number of technical reports and other data received during the comment period for the original proposal and requesting comments on potential modeling analyses to update its risk assessment. In 2013, the Federal EPA also issued a notice of data availability requesting comments on a narrow set of issues.

Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. The Federal EPA opposed the petition and sought additional time to coordinate the issuance of a final rule with the issuance of new effluent limitations under the Clean Water Act (CWA) for utility facilities. In October 2013, the U.S. District Court for the District of Columbia issued a final order partially ruling in favor of the Federal EPA for dismissal of two counts, ruling in favor of the environmental organizations on one count and directing the Federal EPA to provide the court with a proposed schedule for completion of the rulemaking. In January 2014, the parties filed a motion with the court to establish December 2014 as the Federal EPA's deadline for publication of the rule. The court will establish a deadline for the final rule following a comment period for interested parties.

In February 2014, the Federal EPA completed a risk evaluation of the beneficial uses of coal fly ash in concrete and flue gas desulfurization 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. Certain of these uses would no longer be available and others are likely to significantly decline if coal ash and related materials are classified as hazardous wastes. In addition, we currently use surface impoundments and landfills to manage these materials at our generating facilities. We will incur significant costs to upgrade or close and replace these existing facilities under the proposed solid waste management alternative. Regulation of these materials as hazardous wastes would significantly increase these costs. As the rule is not final, we are unable to determine a range of potential costs that are reasonably possible of occurring but expect the costs to be significant.

Clean Water Act Regulations

In 2011, the Federal EPA issued a proposed rule setting forth standards for existing power plants that will reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. Entrainment is when small fish, eggs or larvae are drawn into the cooling water system and affected by heat, chemicals or physical stress. The proposed standards affect all plants withdrawing more than two million gallons of cooling water per day and establish specific intake design and intake velocity standards meant to allow fish to avoid or escape impingement. Compliance with this standard is required within eight years of the effective date of the final rule. The proposed standard for entrainment for existing facilities requires a site-specific evaluation of the available measures for reducing entrainment. The proposed entrainment standard for new units at existing facilities requires either intake flows commensurate with closed cycle cooling or achieving entrainment reductions equivalent to 90% or greater of the reductions that could be achieved with closed cycle cooling. Plants withdrawing more than 125 million gallons of cooling water per day must submit a detailed technology study to be reviewed by the state permitting authority. We are evaluating the proposal and engaged in the collection of additional information regarding the feasibility of implementing this proposal at our facilities. In June 2012, the Federal EPA issued additional Notices of Data Availability and requested public comments. We submitted comments in July 2012. Issuance of a final rule is expected in 2014. We are preparing to begin activities to implement the rule following its issuance and an analysis of the final requirements.

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 March 2014, the Federal EPA and the U.S. Army Corps of Engineers jointly announced that they will be issuing 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 released a pre-publication version of the proposed rule. 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 will continue to evaluate the rule and its financial impact on the AEP System. We plan to submit comments and also participate in the preparation of comments to be filed by various organizations of which we are members.

Climate Change

National public policy makers and regulators in the 11 states we serve have diverse views on climate change. We are currently focused on responding to these emerging views with prudent actions, such as improving energy efficiency, investing in developing cost-effective and less carbon-intensive technologies and evaluating our assets across a range of plausible scenarios and outcomes. We are also active participants in a variety of public policy discussions at state and federal levels to assure that proposed new requirements are feasible and the economies of the states we serve are not placed at a competitive disadvantage.

While comprehensive economy-wide regulation of CO2 emissions might be achieved through future legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO2 emissions under the existing requirements of the CAA.

Several states have adopted programs that directly regulate CO2 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. We are taking steps to comply with these requirements.

Future federal and state legislation or regulations that mandate limits on the emission of CO2 would 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. As a result, mandatory limits could reduce future net income and cash flows and impact financial condition.

For additional information on climate change, other environmental issues and the actions we are taking to address potential impacts, see Part I of the 2013 Form 10-K under the headings entitled “Environmental and Other Matters” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

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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.

During the fourth quarter of 2013, we changed the structure of our internal organization which resulted in a change in the composition of our reportable segments. In accordance with authoritative accounting guidance for segment reporting, prior period financial information has been recast in the financial statements and footnotes to be comparable to the current year presentation of reportable segments.

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by OPCo, TCC and TNC.
- OPCo purchases energy to serve standard service offer 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 operation that transports liquids, coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers.

The table below presents Net Income (Loss) by segment for the three months ended March 31, 2014 and 2013.

	Three Months Ended March 31,	
	2014	2013
	(in millions)	

Vertically Integrated Utilities	$	279	$	181
Transmission and Distribution Utilities		97		87
AEP Transmission Holdco		24		12
Generation & Marketing		163		85
AEP River Operations		3		(2)
Corporate and Other (a)		(5)		1
Net Income	$	561	$	364

(a) While not considered a reportable segment, Corporate and Other primarily includes management and professional services to AEP provided at cost to AEP subsidiaries and 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

First Quarter of 2014 Compared to First Quarter of 2013

Net Income increased from $364 million in 2013 to $561 million in 2014 primarily due to:

- Successful rate proceedings in our various jurisdictions.
- An increase in weather-related usage.
- Higher market prices and increased sales volumes.

Our results of operations are discussed below by operating segment.

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended March 31, 2014	2013
	(in millions)	
Revenues	$ 2,586	$ 2,515
Fuel and Purchased Electricity	1,094	1,201
Gross Margin	1,492	1,314
Other Operation and Maintenance	576	578
Depreciation and Amortization	263	235
Taxes Other Than Income Taxes	96	91
Operating Income	557	410
Interest and Investment Income	1	3
Carrying Costs Income (Expense)	(1)	1
Allowance for Equity Funds Used During Construction	10	9
Interest Expense	(131)	(136)
Income Before Income Tax Expense	436	287
Income Tax Expense	157	106
Net Income	$ 279	$ 181

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended March 31, 2014	2013
	(in millions of KWhs)	
Retail:		
Residential	10,905	9,789
Commercial	6,115	5,845
Industrial	8,332	8,261
Miscellaneous	555	549
Total Retail	25,907	24,444
Wholesale (a)	10,184	NM (b)

(a) Includes Off-system Sales, Municipalities and Cooperatives, Unit Power and Other Wholesale Customers.

(b)	2014 is not comparable to 2013 due to the 2013 asset transfers related to corporate separation as well as the termination of the pool agreement on December 31, 2013.
NM	Not meaningful.

Heating degree days and cooling 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

	Three Months Ended March 31,	
	2014	2013
	(in degree days)	
Eastern Region		
Actual - Heating (a)	2,128	1,705
Normal - Heating (b)	1,593	1,595
Actual - Cooling (c)	-	-
Normal - Cooling (b)	5	5
Western Region		
Actual - Heating (a)	1,186	915
Normal - Heating (b)	887	890
Actual - Cooling (c)	6	10
Normal - Cooling (b)	24	24

(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.

First Quarter of 2014 Compared to First Quarter of 2013

Reconciliation of First Quarter of 2013 to First Quarter of 2014
Net Income from Vertically Integrated Utilities
(in millions)

First Quarter of 2013	$	181
Changes in Gross Margin:		
Retail Margins		90
Off-system Sales		85
Transmission Revenues		10
Other Revenues		(7)
Total Change in Gross Margin		178
Changes in Expenses and Other:		
Other Operation and Maintenance		2
Depreciation and Amortization		(28)
Taxes Other Than Income Taxes		(5)
Interest and Investment Income		(2)
Carrying Costs Income		(2)
Allowance for Equity Funds Used During Construction		1
Interest Expense		5
Total Change in Expenses and Other		(29)
Income Tax Expense		(51)
First Quarter of 2014	$	279

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 $90 million primarily due to the following:
  - Successful rate proceedings in our service territories which include:
    - A $26 million increase primarily due to changes in rates in West Virginia.
    - A $24 million rate increase for SWEPCo.
    - A $22 million rate increase for I&M.
    - A $13 million rate increase for KPCo.

    For the rate increases described above, $26 million relates to riders/trackers which have corresponding increases in other expense items below.
  - A $55 million increase in weather-related usage in our eastern and western regions primarily due to increases of 25% and 30%, respectively, in heating degree days.

  These increases were partially offset by:
  - A $42 million increase in PJM expenses net of recovery or offsets.
- Margins from Off-system Sales increased $85 million primarily due to higher market prices.
- Transmission Revenues increased $10 million primarily due to increased investment in the PJM and SPP regions. These increased revenues are partially offset in Other Operation and Maintenance expenses below.

- Other Revenues decreased $7 million primarily due to a decrease in barging. This decrease in barging is a result of the River Transportation Division (RTD) no longer serving Ohio plants transferred to AGR as a result of corporate separation. The decrease in RTD revenue was offset by a decrease in Other Operation and Maintenance expenses for barging.

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

- Other Operation and Maintenance expenses decreased $2 million primarily due to the following:
  - A $30 million write-off in 2013 of previously deferred Virginia storm costs resulting from the 2013 enactment of a Virginia law.
  - A $12 million decrease in storm-related expenses primarily in APCo's service territory.

  These decreases were partially offset by:
  - A $25 million increase due to a favorable settlement of an insurance claim in the first quarter of 2013.
  - A $17 million increase in PJM and other transmission expenses.
- Depreciation and Amortization expenses increased $28 million primarily due to overall higher depreciable property balances.
- Interest Expense decreased $5 million primarily due to a decrease in interest on long-term debt.
- Income Tax Expense increased $51 million primarily due to an increase in pretax book income.

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Three Months Ended March 31, 2014	2013
	(in millions)	
Revenues	$ 1,215	$ 1,134
Fuel and Purchased Electricity	403	449
Amortization of Generation Deferrals	31	-
Gross Margin	781	685
Other Operation and Maintenance	293	244
Depreciation and Amortization	161	133
Taxes Other Than Income Taxes	119	104
Operating Income	208	204
Interest and Investment Income	3	1
Carrying Costs Income	7	3
Allowance for Equity Funds Used During Construction	3	2
Interest Expense	(70)	(75)
Income Before Income Tax Expense	151	135
Income Tax Expense	54	48
Net Income	$ 97	$ 87

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended March 31, 2014	2013
Retail:		
Residential	7,527	6,466
Commercial	5,902	5,706
Industrial	5,143	5,500
Miscellaneous	171	160
Total Retail (a)	18,743	17,832
Wholesale (b)	700	NM (c)

(a)	Represents energy delivered to distribution customers.
(b)	Includes Off-system Sales, Municipalities and Cooperatives, Unit Power and Other Wholesale Customers.
(c)	2014 is not comparable to 2013 due to the 2013 asset transfers related to corporate separation as well as the termination of the pool agreement on December 31, 2013.
NM	Not meaningful.

Heating degree days and cooling 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

	Three Months Ended March 31,	
	2014	2013
	(in degree days)	
Eastern Region		
Actual - Heating (a)	2,409	1,971
Normal - Heating (b)	1,880	1,885
Actual - Cooling (c)	-	-
Normal - Cooling (b)	3	3
Western Region		
Actual - Heating (a)	300	135
Normal - Heating (b)	196	201
Actual - Cooling (d)	70	137
Normal - Cooling (b)	108	105

(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.

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First Quarter of 2014 Compared to First Quarter of 2013

Reconciliation of First Quarter of 2013 to First Quarter of 2014
Net Income from Transmission and Distribution Utilities
(in millions)

First Quarter of 2013	$	87
Changes in Gross Margin:		
Retail Margins		73
Transmission Revenues		14
Other Revenues		9
Total Change in Gross Margin		96
Changes in Expenses and Other:		
Other Operation and Maintenance		(49)
Depreciation and Amortization		(28)
Taxes Other Than Income Taxes		(15)
Interest and Investment Income		2
Carrying Costs Income		4
Allowance for Equity Funds Used During Construction		1
Interest Expense		5
Total Change in Expenses and Other		(80)
Income Tax Expense		(6)
First Quarter of 2014	$	97

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 $73 million primarily due to the following:
  - A $29 million increase for TCC and TNC primarily due to a 325% and 39% increase in heating degree days, respectively.
  - An $17 million increase primarily due to increased connected load for OPCo and corporate separation of OPCo’s generation assets and liabilities that took effect December 31, 2013.
  - A $15 million increase in revenues associated with the Distribution Investment Recovery Rider and Universal Service Fund (USF) surcharge. Of these increases, $10 million relate to riders/trackers which have corresponding increases in other expense items below.
- Transmission Revenues increased $14 million primarily due to increased transmission revenues from Ohio customers who switched to alternative CRES providers and rate increases for customers in the PJM region.
- Other Revenues increased $9 million primarily due to increased Texas securitization revenues.

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

- Other Operation and Maintenance expenses increased $49 million primarily due to the following:

  - A $27 million increase primarily due to PJM and ERCOT expenses. This increase is offset by an increase in Retail Margins above.
  - An $8 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 is offset by an increase in Retail Margins above.
  - An $8 million increase in distribution expenses.
  - A $5 million increase in storm-related expenses primarily in OPCo's service territory.
- Depreciation and Amortization expenses increased $28 million primarily related to the following:
  - A $19 million increase in amortization related to TCC and OPCo securitizations.
  - A $4 million increase for OPCo due to carrying charge adjustments as a result of expensing certain gridSMART® capital projects.
  - A $3 million increase due to an increase in depreciable base of transmission and distribution assets.
- Taxes Other Than Income Taxes increased $15 million primarily due to increased property taxes.
- Income Tax Expense increased $6 million primarily due to an increase in pretax book income.

AEP TRANSMISSION HOLDCO

First Quarter of 2014 Compared to First Quarter of 2013

Net Income from our AEP Transmission Holdco segment increased from $12 million in 2013 to $24 million in 2014 primarily due to an increase in investments by our wholly-owned transmission subsidiaries and ETT.

GENERATION & MARKETING

Generation & Marketing	Three Months Ended March 31, 2014	2013
	(in millions)	
Revenues	$ 1,251	$ 920
Fuel, Purchased Electricity and Other	805	568
Gross Margin	446	352
Other Operation and Maintenance	116	124
Depreciation and Amortization	57	62
Taxes Other Than Income Taxes	12	16
Operating Income	261	150
Interest and Investment Income	1	-
Interest Expense	(12)	(19)
Income Before Income Tax Expense	250	131
Income Tax Expense	87	46
Net Income	$ 163	$ 85

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended March 31, 2014	2013
	(in millions of MWhs)	
Fuel Type:		
Coal	12	10
Natural Gas	2	2
Total MWhs	14	12

First Quarter of 2014 Compared to First Quarter of 2013

Reconciliation of First Quarter of 2013 to First Quarter of 2014
Net Income from Generation & Marketing
(in millions)

First Quarter of 2013	$	85
Changes in Gross Margin:		
Generation		97
Retail, Trading and Marketing		(3)
Total Change in Gross Margin		94
Changes in Expenses and Other:		
Other Operation and Maintenance		8
Depreciation and Amortization		5
Taxes Other Than Income Taxes		4
Interest and Investment Income		1
Interest Expense		7
Total Change in Expenses and Other		25
Income Tax Expense		(41)
First Quarter of 2014	$	163

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 costs of service for retail operations were as follows:

· Generation increased $94 million primarily due to increases in demand and market prices driven by cold temperatures in 2014.

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

· Other Operation and Maintenance expenses decreased $8 million primarily due to a reduction in employee related expenses.
· Depreciation and Amortization expenses decreased $5 million primarily due to the cessation of depreciation on Muskingum River Plant, Unit 5.
· Interest Expense decreased $7 million primarily due to lower outstanding long-term debt balances and lower long-term interest rates.
· Income Tax Expense increased $41 million primarily due to an increase in pretax book income.

AEP RIVER OPERATIONS

First Quarter of 2014 Compared to First Quarter of 2013

Net Income from our AEP River Operations segment increased from a loss of $2 million in 2013 to income of $3 million in 2014, due to improvements in river conditions as well as improvements in grain export demand.

CORPORATE AND OTHER

First Quarter of 2014 Compared to First Quarter of 2013

Net Income from Corporate and Other decreased from income of $1 million in 2013 to a loss of $5 million in 2014 primarily due to an increase in net interest.

AEP SYSTEM INCOME TAXES

First Quarter of 2014 Compared to First Quarter of 2013

Income Tax Expense increased $112 million primarily due to an increase in pretax book income.

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

	March 31, 2014		December 31, 2013	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 18,087	50.5 %	$ 18,377	52.2 %
Short-term Debt	1,332	3.7	757	2.1
Total Debt	19,419	54.2	19,134	54.3
AEP Common Equity	16,416	45.8	16,085	45.7
Noncontrolling Interests	3	-	1	-
Total Debt and Equity Capitalization	$ 35,838	100.0 %	$ 35,220	100.0 %

Our ratio of debt-to-total capital declined from 54.3% as of December 31, 2013 to 54.2% as of March 31, 2014 primarily due to an increase in our common equity from earnings.

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 March 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-and-leaseback or leasing agreements or common stock.

Commercial Paper Credit Facilities

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

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,750	June 2016
Revolving Credit Facility	1,750	July 2017
Total	3,500	
Cash and Cash Equivalents	292	
Total Liquidity Sources	3,792	

Less:	AEP Commercial Paper Outstanding		632
	Letters of Credit Issued		130
Net Available Liquidity		$	3,030

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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 the first three months of 2014 was $691 million. The weighted-average interest rate for our commercial paper during 2014 was 0.28%.

Other Credit Facilities

In January 2014, we issued letters of credit under an $85 million uncommitted facility signed in October 2013. As of March 31, 2014, the maximum future payment for letters of credit issued under the uncommitted facility was $75 million with a maturity in July 2014. An uncommitted facility gives the issuer of the facility the right to accept or decline each request we make under the facility.

Securitized Accounts Receivable

Our receivables securitization agreement provides a commitment of $700 million from bank conduits to purchase receivables. A commitment of $385 million expires in June 2014. The remaining commitment of $315 million expires in June 2015. We intend to extend or replace the agreement expiring in June 2014 on or before its maturity.

Debt Covenants and Borrowing Limitations

Our revolving 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 revolving credit agreements excludes securitization bonds and debt of AEP Credit. As of March 31, 2014, this contractually-defined percentage was 50.6%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of March 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 does 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. As of March 31, 2014, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.50 per share in April 2014. 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 primarily 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.

We do not believe restrictions related to our various financing arrangements and regulatory requirements 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.

	Three Months Ended March 31,			
	2014		2013	
	(in millions)			
Cash and Cash Equivalents at Beginning of Period	$	118	$	279
Net Cash Flows from Operating Activities		1,133		756
Net Cash Flows Used for Investing Activities		(981)		(772)
Net Cash Flows from (Used for) Financing Activities		22		(84)
Net Increase (Decrease) in Cash and Cash Equivalents		174		(100)
Cash and Cash Equivalents at End of Period	$	292	$	179

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

Operating Activities

	Three Months Ended March 31,			
	2014		2013	
	(in millions)			
Net Income	$	561	$	364
Depreciation and Amortization		491		420
Other		81		(28)
Net Cash Flows from Operating Activities	$	1,133	$	756

Net Cash Flows from Operating Activities were $1.1 billion in 2014 consisting primarily of Net Income of $561 million and $491 million of noncash Depreciation and Amortization partially offset by $137 million of fuel cost deferrals and $56 million of Ohio capacity deferrals as a result of the PUCO's July 2012 approval of a capacity deferral mechanism. 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/book temporary differences from operations. The reduction in Fuel, Material and Supplies balances reflects a decrease in fuel inventory due to the cold winter weather and increased generation.

Net Cash Flows from Operating Activities were $756 million in 2013 consisting primarily of Net Income of $364 million and $420 million 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. Net cash outflows for Accrued Taxes were a result of recording the estimated federal tax loss for tax/book temporary differences.

Investing Activities

	Three Months Ended March 31, 2014	2013
	(in millions)	
Construction Expenditures	$ (907)	$ (843)
Acquisitions of Nuclear Fuel	(49)	(47)
Acquisitions of Assets/Businesses	(43)	(2)
Insurance Proceeds Related to Cook Plant Fire	-	72
Other	18	48
Net Cash Flows Used for Investing Activities	$ (981)	$ (772)

Net Cash Flows Used for Investing Activities were $981 million 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 $772 million in 2013 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Financing Activities

	Three Months Ended March 31, 2014	2013
	(in millions)	
Issuance of Common Stock, Net	$ 15	$ 15
Issuance of Debt, Net	281	139
Dividends Paid on Common Stock	(245)	(230)
Other	(29)	(8)
Net Cash Flows from (Used for) Financing Activities	$ 22	$ (84)

Net Cash Flows from Financing Activities in 2014 were $22 million. Our net debt issuances were $281 million. The net issuances included issuances of $76 million of other debt notes and an increase in short-term borrowing of $575 million offset by retirements of $258 million of senior unsecured and other debt notes and $112 million of securitization bonds. We paid common stock dividends of $245 million. See Note 11 – Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows Used for Financing Activities in 2013 were $84 million. Our net debt issuances were $139 million. The net issuances included issuances of $475 million of senior unsecured notes, a $200 million draw on a $1 billion term credit facility and an increase in short-term borrowing of $326 million offset by retirements of $753 million of senior unsecured and other debt notes and $105 million of securitization bonds. We paid common stock dividends of $230 million.

In April 2014, I&M retired $13 million of Notes Payable related to DCC Fuel.

BUDGETED CONSTRUCTION EXPENDITURES

In April 2014, we increased our forecast for construction expenditures by $250 million to approximately $4.1 billion for 2014. The increase is primarily for transmission investment in the AEP Transmission Holdco, Vertically Integrated Utilities and Transmission and Distribution Utilities segments.

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:

	March 31, 2014	December 31, 2013
	(in millions)	
Rockport Plant, Unit 2 Future Minimum Lease Payments	$ 1,330	$ 1,330
Railcars Maximum Potential Loss from Lease Agreement	19	19

For complete information on each of these off-balance sheet arrangements, see the “Off-balance Sheet Arrangements” section of “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in the 2013 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of our contractual obligations is included in our 2013 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in the “Cash Flow” section above.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

See the “Critical Accounting Policies and Estimates” section of “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in the 2013 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

ACCOUNTING PRONOUNCEMENTS

Pronouncements Effective in the Future

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. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014. We plan to adopt ASU 2014-08 effective January 1, 2015.

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 revenue recognition, financial instruments, leases, insurance, hedge accounting and consolidation policy. The ultimate pronouncements resulting from these and future projects could have an impact on 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 congestion during the June 2012 – May 2015 Ohio ESP period. Additional risk includes 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 AEP 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)
Three Months Ended March 31, 2014

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation and 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	(6)	(3)	(16)	(25)
Fair Value of New Contracts at Inception When Entered During the Period (a)	-	-	5	5
Net Option Premiums Paid for Unexercised or Unexpired Option Contracts Entered During the Period	-	-	1	1
Changes in Fair Value Due to Market Fluctuations During the Period (b)	-	-	11	11
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	10	4	-	14
Total MTM Risk Management Contract Net Assets as of March 31, 2014	$ 36	$ 4	$ 158	198
Commodity Cash Flow Hedge Contracts				8
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				(2)
Fair Value Hedge Contracts				(8)
Collateral Deposits				(2)
Total MTM Derivative Contract Net Assets as of March 31, 2014				$ 194

(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 condensed statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 8 – Derivatives and Hedging and Note 9 – 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 March 31, 2014, our credit exposure net of collateral to sub investment grade counterparties was approximately 9.2%, 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 March 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	$ 528	$ 10	$ 518	2	$ 256
Split Rating	-	-	-	-	-
Noninvestment Grade	1	1	-	-	-
No External Ratings:					
Internal Investment Grade	70	-	70	4	41
Internal Noninvestment Grade	70	11	59	3	43
Total as of March 31, 2014	$ 669	$ 22	$ 647	9	$ 340
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 March 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 table shows the end, high, average and low market risk as measured by VaR for the trading portfolio for the periods indicated:

VaR Model

Three Months Ended March 31, 2014				Twelve Months Ended December 31, 2013			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 1	$ 3	$ 1	$ -	$ -	$ 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 portfolio to understand our exposure to extreme price movements. We employ a historical-based method whereby the current 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 March 31, 2014 and December 31, 2013, the estimated EaR on our debt portfolio for the following twelve months was $33 million and $32 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2014 and 2013
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended March 31, 2014		Three Months Ended March 31, 2013	
REVENUES				
Vertically Integrated Utilities	$	2,549	$	2,356
Transmission and Distribution Utilities		1,161		1,090
Generation & Marketing		821		258
Other Revenues		117		122
TOTAL REVENUES		4,648		3,826
EXPENSES				
Fuel and Other Consumables Used for Electric Generation		1,168		1,031
Purchased Electricity for Resale		638		371
Other Operation		780		738
Maintenance		292		293
Depreciation and Amortization		491		420
Taxes Other Than Income Taxes		238		218
TOTAL EXPENSES		3,607		3,071
OPERATING INCOME		1,041		755
Other Income (Expense):				
Interest and Investment Income		1		3
Carrying Costs Income		6		4
Allowance for Equity Funds Used During Construction		22		15
Interest Expense		(220)		(232)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS		850		545
Income Tax Expense		307		195
Equity Earnings of Unconsolidated Subsidiaries		18		14
NET INCOME		561		364
Net Income Attributable to Noncontrolling Interests		1		1
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$	560	$	363
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING		487,867,089		485,823,668
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON				

SHAREHOLDERS	$	1.15	$	0.75
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING		488,271,167		486,344,036
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$	1.15	$	0.75
CASH DIVIDENDS DECLARED PER SHARE	$	0.50	$	0.47

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 35.