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 r 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.
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- 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 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 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.

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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.

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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	Three Months Ended March 31, 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	Three Months Ended March 31, 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.

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

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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 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.

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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.

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

	Three Months Ended March 31,			
	2014		2013	
Net Income	$	561	$	364
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $3 and $13 in 2014 and 2013, Respectively		5		24
Securities Available for Sale, Net of Tax of $- and $1 in 2014 and 2013, Respectively		-		1
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $- and $3 in 2014 and 2013, Respectively		1		6
TOTAL OTHER COMPREHENSIVE INCOME		6		31
TOTAL COMPREHENSIVE INCOME		567		395
Total Comprehensive Income Attributable to Noncontrolling Interests		1		1
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$	566	$	394

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

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Three Months Ended March 31, 2014 and 2013
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2012	506	$ 3,289	$ 6,049	$ 6,236	$ (337)	$ -	$ 15,237
Issuance of Common Stock		2	13				15
Common Stock Dividends				(229)		(1)	(230)
Other Changes in Equity			4				4
Net Income				363		1	364
Other Comprehensive Income					31		31
TOTAL EQUITY – MARCH 31, 2013	506	$ 3,291	$ 6,066	$ 6,370	$ (306)	$ -	$ 15,421
TOTAL EQUITY – DECEMBER 31, 2013	508	$ 3,303	$ 6,131	$ 6,766	$ (115)	$ 1	$ 16,086
Issuance of Common Stock		2	13				15
Common Stock Dividends				(244)		(1)	(245)
Other Changes in Equity				(6)		2	(4)
Net Income				560		1	561
Other Comprehensive Income					6		6
TOTAL EQUITY – MARCH 31, 2014	508	$ 3,305	$ 6,144	$ 7,076	$ (109)	$ 3	$ 16,419

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

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

	March 31, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$ 292	$ 118
Other Temporary Investments (March 31, 2014 and December 31, 2013 Amounts Include $293 and $335, Respectively, Related to Transition Funding, Phase-in-Recovery Funding, Consumer Rate Relief Funding and EIS)	310	353
Accounts Receivable:		
Customers	785	746
Accrued Unbilled Revenues	143	157
Pledged Accounts Receivable - AEP Credit	1,015	945
Miscellaneous	66	72
Allowance for Uncollectible Accounts	(66)	(60)
Total Accounts Receivable	1,943	1,860
Fuel	490	701
Materials and Supplies	724	722
Risk Management Assets	125	160
Regulatory Asset for Under-Recovered Fuel Costs	175	80
Margin Deposits	117	70
Prepayments and Other Current Assets	159	246
TOTAL CURRENT ASSETS	4,335	4,310
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	25,174	25,074
Transmission	11,014	10,893
Distribution	16,518	16,377
Other Property, Plant and Equipment (Including Plant to be Retired, Coal Mining and Nuclear Fuel)	5,552	5,470
Construction Work in Progress	2,836	2,471
Total Property, Plant and Equipment	61,094	60,285
Accumulated Depreciation and Amortization	19,564	19,288
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	41,530	40,997
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,384	4,376
Securitized Assets	2,308	2,373
Spent Nuclear Fuel and Decommissioning Trusts	1,962	1,932

Goodwill		91		91
Long-term Risk Management Assets		266		297
Deferred Charges and Other Noncurrent Assets		2,162		2,038
TOTAL OTHER NONCURRENT ASSETS		11,173		11,107
TOTAL ASSETS	$	57,038	$	56,414

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

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

	March 31, 2014	December 31, 2013
CURRENT LIABILITIES		
Accounts Payable	$ 1,213	$ 1,266
Short-term Debt:		
Securitized Debt for Receivables - AEP Credit	700	700
Other Short-term Debt	632	57
Total Short-term Debt	1,332	757
Long-term Debt Due Within One Year (March 31, 2014 and December 31, 2013 Amounts Include $449 and $416, Respectively, Related to Transition Funding, DCC Fuel, Phase-in-Recovery Funding, Consumer Rate Relief Funding and Sabine)	1,612	1,549
Risk Management Liabilities	60	90
Customer Deposits	302	299
Accrued Taxes	803	822
Accrued Interest	220	245
Regulatory Liability for Over-Recovered Fuel Costs	60	119
Other Current Liabilities	917	965
TOTAL CURRENT LIABILITIES	6,519	6,112
NONCURRENT LIABILITIES		
Long-term Debt (March 31, 2014 and December 31, 2013 Amounts Include $2,388 and $2,532, Respectively, Related to Transition Funding, DCC Fuel, Phase-in-Recovery Funding, Consumer Rate Relief Funding, Transource Energy and Sabine)	16,475	16,828
Long-term Risk Management Liabilities	137	177
Deferred Income Taxes	10,446	10,300
Regulatory Liabilities and Deferred Investment Tax Credits	3,765	3,694
Asset Retirement Obligations	1,853	1,835
Employee Benefits and Pension Obligations	456	415
Deferred Credits and Other Noncurrent Liabilities	968	967
TOTAL NONCURRENT LIABILITIES	34,100	34,216
TOTAL LIABILITIES	40,619	40,328
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		
2014 2013		

Shares Authorized	600,000,000	600,000,000		
Shares Issued	508,397,086	508,113,964		
(20,336,592 Shares were Held in Treasury as of March 31, 2014 and December 31, 2013)			3,305	3,303
Paid-in Capital			6,144	6,131
Retained Earnings			7,076	6,766
Accumulated Other Comprehensive Income (Loss)			(109)	(115)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			16,416	16,085
Noncontrolling Interests			3	1
TOTAL EQUITY			16,419	16,086
TOTAL LIABILITIES AND EQUITY			$ 57,038	$ 56,414

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

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2014 and 2013
(in millions)
(Unaudited)

	Three Months Ended March 31, 2014	2013
OPERATING ACTIVITIES		
Net Income	$ 561	$ 364
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	491	420
Deferred Income Taxes	299	246
Carrying Costs Income	(6)	(4)
Allowance for Equity Funds Used During Construction	(22)	(15)
Mark-to-Market of Risk Management Contracts	6	34
Amortization of Nuclear Fuel	38	34
Property Taxes	(54)	(51)
Fuel Over/Under-Recovery, Net	(137)	(4)
Deferral of Ohio Capacity Costs, Net	(56)	(49)
Change in Other Noncurrent Assets	(25)	36
Change in Other Noncurrent Liabilities	77	17
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(83)	(4)
Fuel, Materials and Supplies	209	(1)
Accounts Payable	33	(3)
Accrued Taxes, Net	(16)	(69)
Other Current Assets	(51)	(16)
Other Current Liabilities	(131)	(179)
Net Cash Flows from Operating Activities	1,133	756
INVESTING ACTIVITIES		
Construction Expenditures	(907)	(843)
Change in Other Temporary Investments, Net	44	75
Purchases of Investment Securities	(165)	(196)
Sales of Investment Securities	148	168
Acquisitions of Nuclear Fuel	(49)	(47)
Acquisitions of Assets/Businesses	(43)	(2)
Insurance Proceeds Related to Cook Plant Fire	-	72
Other Investing Activities	(9)	1
Net Cash Flows Used for Investing Activities	(981)	(772)
FINANCING ACTIVITIES		
Issuance of Common Stock, Net	15	15
Issuance of Long-term Debt	76	671
Commercial Paper and Credit Facility Borrowings	-	17
Change in Short-term Debt, Net	575	329

Retirement of Long-term Debt		(370)		(858)
Commercial Paper and Credit Facility Repayments		-		(20)
Principal Payments for Capital Lease Obligations		(33)		(16)
Dividends Paid on Common Stock		(245)		(230)
Other Financing Activities		4		8
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 Beginning of Period		118		279
Cash and Cash Equivalents at End of Period	$	292	$	179
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	234	$	253
Net Cash Paid (Received) for Income Taxes		(6)		(19)
Noncash Acquisitions Under Capital Leases		20		24
Construction Expenditures Included in Current Liabilities as of March 31,		387		300

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

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

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed consolidated financial statements and footnotes were prepared in accordance with GAAP for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed consolidated interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of our net income, financial position and cash flows for the interim periods. Net income for the three months ended March 31, 2014 is not necessarily indicative of results that may be expected for the year ending December 31, 2014. The condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2013 consolidated financial statements and notes thereto, which are included in our Form 10-K as filed with the SEC on February 25, 2014.

Revenue Recognition

Electricity Supply and Delivery Activities – Transactions with PJM

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. For regulated and nonregulated operations, we recognize the revenues on the statements of income upon delivery of the energy to the customer and include unbilled as well as billed amounts.

APCo, I&M and KPCo sell power produced at their generation plants to PJM and purchase power from PJM to supply their retail load. These power sales and purchases for each subsidiary's retail load are netted hourly for financial reporting purposes. On an hourly net basis, each subsidiary records sales of power to PJM in excess of purchases of power from PJM as revenue on the statements of income. Also, on an hourly net basis, each subsidiary records purchases of power from PJM to serve retail load in excess of sales of power to PJM as Purchased Electricity for Resale on the statements of income. Upon termination of the Interconnection Agreement, each subsidiary manages and accounts for its purchases and sales with PJM individually based on market prices.

AEP's nonregulated subsidiaries also purchase power from PJM and sell power to PJM. With the exception of certain dedicated load bilateral power supply contracts, these transactions are reported as gross purchases and sales.

Earnings Per Share (EPS)

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

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

	Three Months Ended March 31,	
	2014	2013

	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 560		$ 363	
Weighted Average Number of Basic Shares Outstanding	487.9	$ 1.15	485.8	$ 0.75
Weighted Average Dilutive Effect of:				
Restricted Stock Units	0.4	-	0.5	-
Weighted Average Number of Diluted Shares Outstanding	488.3	$ 1.15	486.3	$ 0.75

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

2. NEW ACCOUNTING PRONOUNCEMENT

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

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

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

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014. If applicable, this standard will change the presentation of our financial statements but will not affect the calculation of net income, comprehensive income or earnings per share. We plan to adopt ASU 2014-08 effective January 1, 2015.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

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

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2014

	Cash Flow Hedges				
	Commodity	Interest Rate and Foreign Currency	Securities Available for Sale	Pension and OPEB	Total
			(in millions)		
Balance in AOCI as of December 31, 2013	$ -	$ (23)	$ 7	$ (99)	$ (115)
Change in Fair Value Recognized in AOCI	(14)	-	-	-	(14)
Amounts Reclassified from AOCI	18	1	-	1	20
Net Current Period Other Comprehensive Income	4	1	-	1	6
Balance in AOCI as of March 31, 2014	$ 4	$ (22)	$ 7	$ (98)	$ (109)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2013

Cash Flow Hedges

	Commodity	Interest Rate and Foreign Currency	Securities Available for Sale (in millions)	Pension and OPEB	Total
Balance in AOCI as of December 31, 2012	$ (8)	$ (30)	$ 4	$ (303)	$ (337)
Change in Fair Value Recognized in AOCI	18	3	1	-	22
Amounts Reclassified from AOCI	2	1	-	6	9
Net Current Period Other Comprehensive Income	20	4	1	6	31
Balance in AOCI as of March 31, 2013	$ 12	$ (26)	$ 5	$ (297)	$ (306)

Reclassifications from Accumulated Other Comprehensive Income

The following table provides details of reclassifications from AOCI for the three months ended March 31, 2014 and 2013. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 6 for additional details.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended March 31, 2014 and 2013

		Amount of (Gain) Loss Reclassified from AOCI	
		Three Months Ended March 31,	
		2014	2013
Gains and Losses on Cash Flow Hedges		(in millions)	
Commodity:			
	Vertically Integrated Utilities Revenues	$ -	$ -
	Generation & Marketing Revenues	-	(3)
	Purchased Electricity for Resale	31	6
	Property, Plant and Equipment	-	-
	Regulatory Assets/(Liabilities), Net (a)	(3)	-
Subtotal - Commodity		28	3
Interest Rate and Foreign Currency:			
	Interest Expense	2	2
Subtotal - Interest Rate and Foreign Currency		2	2
Reclassifications from AOCI, before Income Tax (Expense) Credit		30	5
Income Tax (Expense) Credit		11	2
Reclassifications from AOCI, Net of Income Tax (Expense) Credit		19	3
Gains and Losses on Securities Available for Sale			
Interest Income		-	-
Interest Expense		-	-
Reclassifications from AOCI, before Income Tax (Expense) Credit		-	-
Income Tax (Expense) Credit		-	-
Reclassifications from AOCI, Net of Income Tax (Expense) Credit		-	-
Pension and OPEB			
Amortization of Prior Service Cost (Credit)		(5)	(5)
Amortization of Actuarial (Gains)/Losses		7	14
Reclassifications from AOCI, before Income Tax (Expense) Credit		2	9

Income Tax (Expense) Credit		1		3
Reclassifications from AOCI, Net of Income Tax (Expense) Credit		1		6
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$	20	$	9

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

4. RATE MATTERS

As discussed in the 2013 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2013 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2014 and updates the 2013 Annual Report.

Regulatory Assets Not Yet Being Recovered

Noncurrent Regulatory Assets	March 31, 2014	December 31, 2013
	(in millions)	
Regulatory assets not yet being recovered pending future proceedings:		
Regulatory Assets Currently Earning a Return		
Storm Related Costs	$ 21	$ 22
Ohio Economic Development Rider	-	14
Other Regulatory Assets Not Yet Being Recovered	-	4
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	104	161
Indiana Under-Recovered Capacity Costs	28	22
IGCC Pre-Construction Costs	21	-
Expanded Net Energy Charge - Coal Inventory	19	21
Mountaineer Carbon Capture and Storage Product Validation Facility	13	13
Ormet Special Rate Recovery Mechanism	10	36
Other Regulatory Assets Not Yet Being Recovered	34	37
Total Regulatory Assets Not Yet Being Recovered	$ 250	$ 330

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

OPCo Rate Matters

Ohio Electric Security Plan Filings

2009 – 2011 ESP

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

In October 2011, the PUCO issued an order in the remand proceeding. As a result, OPCo ceased collection of POLR billings in November 2011 and recorded a write-off in 2011 related to POLR collections for the period June 2011 through October 2011. In February 2012, the Ohio Consumers' Counsel and the IEU filed appeals of that order with the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge, which, if ordered, could reduce OPCo's net deferred fuel costs up to the total balance. As of March

31, 2014, OPCo's net deferred fuel balance was $426 million, excluding unrecognized equity carrying costs. In February 2014, the Supreme Court of Ohio affirmed the PUCO's decision and rejected all appeals filed by the OCC and the IEU. In February 2014, the IEU filed for reconsideration of the Supreme Court of Ohio decision.

In August 2012, the PUCO issued an order in a separate proceeding which implemented a PIRR to recover deferred fuel costs in rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. In November 2012, OPCo filed an appeal at the Supreme Court of Ohio related to the PUCO decision in the PIRR proceeding claiming a long-term debt rate modified the previously adjudicated 2009 – 2011 ESP order, which granted a weighted average cost of capital rate. In November 2012, the IEU and the OCC filed appeals regarding the PUCO decision in the PIRR proceeding. These appeals principally argued that the PUCO should have reduced the deferred fuel balance to reflect the prior "improper" collection of POLR revenues which could reduce OPCo's net deferred fuel balance up to the total balance. These intervenors' appeals also argued that carrying costs should be reduced due to an accumulated deferred income tax credit which, as of March 31, 2014, could reduce carrying costs by $30 million including $16 million of unrecognized equity carrying costs. A decision from the Supreme Court of Ohio is pending.

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

June 2012 – May 2015 ESP Including Capacity Charge

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

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the RPM price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The OPCo RPM price, 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. As of March 31, 2014, OPCo's incurred deferred capacity costs balance of $348 million, including debt carrying costs, was recorded in Regulatory Assets on the balance sheet.

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

In November 2013, the PUCO issued an order approving OPCo's CBP with modifications. The modifications include the delay of the energy auctions that were originally ordered in the ESP order. As ordered, 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, including the Distribution Investment Rider, 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 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.

Significantly Excessive Earnings Test (SEET) Filings

In January 2011, the PUCO issued an order on the 2009 SEET filing. The order gave consideration for a future commitment to invest $20 million to support the development of a large solar farm. In January 2013, the PUCO found there was not a need for the large solar farm. The PUCO noted that OPCo remains obligated to spend $20 million on this solar project or another project. In September 2013, a proposed second phase of OPCo's gridSMART® program was filed with the PUCO which included a proposed project to satisfy this PUCO directive. A decision from the PUCO is pending. In November 2013, OPCo filed its 2011 SEET filing with the PUCO. OPCo was required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. In March 2014, the PUCO approved a stipulation agreement between OPCo and the PUCO staff in which both parties agree that there were no significantly excessive earnings in 2011 for CSPCo or OPCo.

In November 2013, OPCo filed its 2012 SEET filing with the PUCO. In April 2014, OPCo entered into a stipulation agreement with the PUCO staff in which both parties agree that there were no significantly excessive earnings in 2012 for OPCo. A hearing at the PUCO related to the 2012 SEET filing is scheduled for April 2014. Management does not believe that there were significantly excessive earnings in 2013 for OPCo.

Corporate Separation

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

Storm Damage Recovery Rider (SDRR)

In December 2012, OPCo submitted an application with the PUCO to establish initial SDRR rates to recover 2012 incremental storm distribution expenses over twelve months starting with the effective date as approved by the PUCO. In December 2013, a stipulation agreement was reached between OPCo, the PUCO staff and all intervenors except the OCC. The stipulation agreement recommended approval to recover $55 million related to 2012 storm costs over a 12-month period which included a $6 million reduction in the amount of 2012 storm expenses to be recovered. The agreement also provided that carrying charges using a long-term debt rate will be assessed from April 2013 until recovery begins, but no additional carrying charges will accrue during the actual recovery period. In April 2014, the PUCO approved the settlement agreement. Compliance tariffs were filed with the PUCO and new rates were implemented in April 2014.

2009 Fuel Adjustment Clause Audit

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

In August 2012, intervenors filed an appeal with the Supreme Court of Ohio claiming the settlement credit ordered by the PUCO should have reflected the remaining gain not already flowed through the FAC with carrying charges, which, if ordered, would be $35 million plus carrying charges. If the Supreme Court of Ohio ultimately determines that additional amounts should benefit ratepayers, it could reduce future net income and cash flows and impact financial condition.

2010 and 2011 Fuel Adjustment Clause Audits

The PUCO-selected outside consultant issued its 2010 and 2011 FAC audit reports which included a recommendation that the PUCO reexamine the carrying costs on the deferred FAC balance and determine whether the carrying costs on the balance should be net of accumulated income taxes with the use of a weighted average cost of capital (WACC). The PUCO subsequently ruled in the PIRR proceeding that the fuel clause for these years was approved with a WACC carrying cost and that the carrying costs on the balance should not be net of accumulated income taxes. Hearings at the PUCO were held in November 2013. If the PUCO orders result in a reduction to the FAC deferral, it could reduce future net income and cash flows and impact financial condition. See the 2009 – 2011 ESP section of the "Ohio Electric Security Plan Filing" related to the PUCO order in the PIRR proceeding.

2012 – 2013 Fuel Adjustment Clause Audits

In April 2014, the PUCO-selected outside consultant provided its preliminary draft report related to their 2012 and 2013 FAC audit which included certain unfavorable recommendations related to the FAC recovery for 2012 and 2013. If the PUCO orders a reduction to the FAC deferral, it could reduce future net income and cash flows and impact financial condition.

Ormet

Ormet, a large aluminum company, had a contract to purchase power from OPCo through 2018. In February 2013, Ormet filed Chapter 11 bankruptcy proceedings in the state of Delaware. In October 2013, Ormet announced that it was unable to emerge from bankruptcy and shut down operations effective immediately. Based upon previous PUCO rulings providing rate assistance to Ormet, the PUCO is expected to permit OPCo to recover unpaid Ormet amounts through the Economic Development Rider (EDR), except where recovery from ratepayers is limited to $20 million related to previously deferred payments from Ormet's October and November 2012 power bills. OPCo expects that any additional unpaid generation usage by Ormet will be recoverable as a regulatory asset through the EDR. In February 2014, a stipulation agreement between OPCo and Ormet was filed with the PUCO. The stipulation recommends approval of OPCo's right to fully recover approximately $49 million of foregone revenues through the EDR which, as of March 31, 2014, is recorded in regulatory assets on the balance sheet. Also in February 2014, intervenor comments were filed objecting to full recovery of these foregone revenues. In March 2014, the PUCO issued an order in OPCo's EDR filing allowing OPCo to include $39 million of Ormet-related foregone revenues in the EDR effective April 2014. The order stated that if the stipulation agreement between OPCo and Ormet is subsequently adopted by the PUCO, OPCo could file an application to modify the EDR rate for the remainder of the period requesting recovery of the remaining $10 million of Ormet deferrals. In April 2014, an intervenor filed testimony objecting to $5 million of the remaining foregone revenues. A hearing at the PUCO related to the stipulation agreement is scheduled for May 2014.

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

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

Ohio IGCC Plant

In March 2005, OPCo filed an application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. As of March 31, 2014, OPCo has collected $24 million in pre-construction costs authorized in a June 2006 PUCO order. Intervenors have filed motions with the PUCO requesting that OPCo refund all collected pre-construction costs to Ohio ratepayers with interest.

Management cannot predict the outcome of this proceeding concerning the Ohio IGCC plant or what effect, if any, this proceeding could have on future net income and cash flows. However, if OPCo is required to refund pre-construction costs collected, it could reduce future net income and cash flows and impact financial condition.

SWEPCo Rate Matters

2012 Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In October 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determined that the Turk Plant's Texas jurisdictional capital cost cap established in a previous Certificate of Convenience and Necessity case also limited SWEPCo's recovery of AFUDC in addition to limits on its recovery of cash construction costs. Additionally, the PUCT deferred consideration of the requested increase in depreciation expense related to the change in the 2016 retirement date of the Welsh Plant, Unit 2. As of March 31, 2014, the net book value of Welsh Plant, Unit 2 was $86 million, before cost of removal, including materials and supplies inventory and CWIP.

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

If any part of the PUCT order is overturned or if SWEPCo cannot ultimately recover its Texas jurisdictional share of the Turk Plant investment, including AFUDC, or its retirement-related costs of Welsh Plant, Unit 2, it could reduce future net income and cash flows and impact financial condition.

2013 Texas Transmission Cost Recovery Factor Filing

In December 2013, SWEPCo filed an application to implement its initial transmission cost recovery factor (TCRF) requesting additional annual revenue of $10 million. The TCRF is designed to recover increases from the amounts included in SWEPCo's Texas retail base rates for transmission infrastructure improvement costs and wholesale transmission charges under a tariff approved by the FERC. SWEPCo's application included Turk Plant transmission-related costs. In March 2014, the Administrative Law Judge (ALJ) dismissed this case without prejudice. The ALJ concluded that SWEPCo's application was premature as the PUCT had not completed its ruling on the motions for rehearing of the order in the SWEPCo Texas Base Rate Case in which the baseline values to be used in the TCRF calculation would be established.

2012 Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share (approximately 29%) of the Turk Plant. In February 2013, a settlement was filed and approved by the LPSC. The settlement increased Louisiana total rates by approximately $2 million annually, effective March 2013, which consisted of an increase in base rates of approximately $85 million annually offset by a decrease in fuel and other rates of approximately $83 million annually. The March 2013 base rates are based on a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit. The rates are subject to refund based on the staff review of the cost of service and the prudency review of the Turk Plant. The settlement also provided that the LPSC 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.

2014 Louisiana Formula Rate Filing

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

APCo and WPCo Rate Matters

Plant Transfer

In March 2014, APCo and WPCo filed a request with the WVPSC for approval to transfer at net book value to WPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity presently owned by AGR. In April 2014, APCo and WPCo filed testimony that supported their request and proposed a base rate surcharge of $113 million, to be offset by an equal reduction in the ENEC revenues, to be effective upon the transfer of the Mitchell Plant to WPCo. In April 2014, APCo and WPCo also filed a request with the FERC for approval to transfer AGR's one-half interest in the Mitchell Plant to WPCo. Upon transfer of the Mitchell Plant to WPCo, WPCo will no longer purchase power from AGR.

APCo IGCC Plant

As of March 31, 2014, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to its West Virginia jurisdiction, approximately $2 million applicable to its FERC jurisdiction and approximately $10 million applicable to its Virginia jurisdiction. In March 2014, APCo submitted a request to the Virginia SCC as part of the 2014 Virginia Biennial Base Rate Case to amortize the Virginia jurisdictional share of these costs over two years. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2013 Virginia Transmission Rate Adjustment Clause (transmission RAC)

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

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 a change 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 changes in the expected service lives of various generating units and the extended recovery through 2040 of the net book value of certain planned 2015 plant retirements. Additionally, the filing included a request to amortize $7 million annually for two years, beginning February 2015, related to certain deferred costs. A hearing at the Virginia SCC is scheduled for September 2014. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

PSO Rate Matters

2014 Oklahoma Base Rate Case

In January 2014, PSO filed a request with the OCC to increase annual base rates by $38 million, based upon a 10.5% return on common equity. This revenue increase includes a proposed increase in depreciation rates of $29 million. In addition, the filing proposed recovery of advanced metering costs through a separate rider over a three-year deployment period requesting $7 million of revenues in year one, increasing to $28 million in year three. The filing also proposed expansion of an existing transmission rider currently recovered in base rates to include additional transmission-related costs that are expected to increase over the next several years.

In April 2014, OCC Staff and intervenors filed testimony with recommendations that included adjustments to annual base rates ranging from an increase of $16 million to a reduction of $22 million, primarily based upon the determination of depreciation rates and a return on common equity between 9.18% and 9.5%. Additionally, the recommendations did not support the advanced metering rider or the expansion of the transmission rider. A hearing at the OCC is scheduled for June 2014. If the OCC were to disallow any portion of this base rate request, it could reduce future net income and cash flows and impact financial condition.

I&M Rate Matters

2011 Indiana Base Rate Case

In February 2013, the IURC issued an order that granted an $85 million annual increase in base rates based upon a return on common equity of 10.2% and adjusted the authorized annual increase in base rates to $92 million in March 2013. In March 2013, the Indiana Office of Utility Consumer Counselor (OUCC) filed an appeal of the order with the Indiana Court of Appeals. In March 2014, the Indiana Court of Appeals upheld the February 2013 IURC order. In April 2014, the OUCC filed an appeal to the Indiana Supreme Court related to the inclusion of a prepaid pension asset in rate base. If any part of the IURC order is overturned by the Indiana Supreme Court, it could reduce future net income and cash flows.

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 that might accommodate a future potential power uprate which the IURC stated I&M could seek recovery of in a subsequent base rate case. I&M will recover approved costs through an LCM rider which will be determined in semi-annual proceedings. The IURC authorized deferral accounting for costs incurred related to certain projects effective January 2012 to the extent such costs are not reflected in rates. In 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.

Tanners Creek Plant, Units 1 - 4

In 2011, I&M announced that it would retire Tanners Creek Plant, Units 1-3 by June 2015 to comply with proposed environmental regulations. In September 2013, I&M announced that Tanners Creek Plant, Unit 4 would also be retired in mid-2015 rather than being converted from coal to natural gas. I&M is currently recovering depreciation and a return on the net book value of the Tanners Creek Plant in base rates and plans to seek recovery of all of the plant's retirement related costs in its next Indiana and Michigan base rate cases.

In December 2013, I&M filed an application with the MPSC seeking approval of revised depreciation rates for Rockport Plant, Unit 1 and Tanners Creek Plant due to the retirement of the Tanners Creek Plant in 2015. Upon the retirement of the Tanners Creek Plant, I&M proposes that the net book value of the Tanners Creek Plant will be recovered over the remaining life of the Rockport Plant. I&M requested to have the impact of these new depreciation rates incorporated into the rates set in its next rate case. The new depreciation rates are expected to result in a decrease in I&M's Michigan jurisdictional electric depreciation expense which I&M proposes to implement in the month following a MPSC order in the revised depreciation case. A hearing at the MPSC is scheduled for September 2014.

As of March 31, 2014, the net book value of the Tanners Creek Plant was $334 million, before cost of removal, including materials and supplies inventory and CWIP. If I&M is ultimately not permitted to fully recover its net book value of the Tanners Creek Plant and its retirement-related costs, it could reduce future net income and cash flows and impact financial condition.

KPCo Rate Matters

Plant Transfer

In October 2012, the AEP East Companies submitted several filings with the FERC. In December 2012, KPCo filed a request with the KPSC for approval to transfer at net book value to KPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity. KPCo also requested that costs related to the Big Sandy Plant, Unit 2 FGD project be established as a regulatory asset. As of March 31, 2014, the net book value of Big Sandy Plant, Unit 2 was $247 million, before cost of removal, including materials and supplies inventory and CWIP.

In October 2013, the KPSC issued an order approving a modified settlement agreement between KPCo, Kentucky Industrial Utility Customers, Inc. and the Sierra Club. The modified settlement approved the transfer of a one-half interest in the Mitchell Plant to KPCo at net book value on December 31, 2013 with the limitation that the net book value of the Mitchell Plant transfer not exceed the amount to be determined by a WVPSC order. The WVPSC order was subsequently issued in December 2013, but the WVPSC deferred a decision on the transfer of the one-half interest in the Mitchell Plant to APCo. The settlement also included the implementation of an Asset Transfer Rider to collect $44 million annually effective January 2014, subject to true-up, and allowed KPCo to retain any off-system sales margins above the $15.3 million annual level in base rates. Additionally, the settlement allows for KPCo to file a Certificate of Public Convenience and Necessity to convert Big Sandy Plant, Unit 1 to natural gas, provided the cost is approximately $60 million, and addressed potential greenhouse gas initiatives on the Mitchell Plant. The settlement also approved recovery, including a return, of coal-related retirement costs related to Big Sandy Plant over 25 years when base rates are set in the next base rate case (no earlier than June 2015), but rejected KPCo’s request to defer FGD project costs for Big Sandy Plant, Unit 2. As a result of this order, in 2013, KPCo recorded a pretax regulatory disallowance of $33 million in Asset Impairments and Other Related Charges on the statement of income. In December 2013, the Attorney General filed an appeal with the Franklin County Circuit Court. In December 2013, KPCo filed motions with the Franklin County Circuit Court to dismiss the appeal. A hearing on the motions to dismiss was held in January 2014. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed. If any part of the KPSC order is overturned, it could reduce future net income and cash flows and impact financial condition.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on our financial statements. The Commitments, Guarantees and Contingencies note within our 2013 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letters of Credit

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

We have two revolving credit facilities totaling $3.5 billion, under which we may issue up to $1.2 billion as letters

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of credit. As of March 31, 2014, the maximum future payments for letters of credit issued under the revolving credit facilities were $130 million with maturities ranging from June 2014 to April 2015.

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.

We have $352 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $356 million. The letters of credit have maturities ranging from July 2014 to March 2017.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $115 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study completed in 2010, we estimate the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately $58 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of March 31, 2014, SWEPCo has collected approximately $62 million through a rider for final mine closure and reclamation costs, of which $16 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $46 million is recorded in Asset Retirement Obligations on our condensed balance sheets.

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

Indemnifications and Other Guarantees

Contracts

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

Master Lease Agreements

We lease certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, we are committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of March 31, 2014, the maximum potential loss for these lease agreements was approximately $21 million assuming the fair value of the equipment is zero at the end of the lease term.

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $13 million and $15 million for

I&M and SWEPCo, respectively, for the remaining railcars as of March 31, 2014.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 83% under the current five year lease term to 77% at the end of the 20-year term of the projected fair value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. The maximum potential losses related to the guarantee are approximately $9 million and $10 million for I&M and SWEPCo, respectively, assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair value would produce a sufficient sales price to avoid any loss.

ENVIRONMENTAL CONTINGENCIES

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

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

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ. I&M’s reserve is approximately $8 million. As the remediation work is completed, I&M’s cost may change as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation required by the MDEQ. We cannot predict the amount of additional cost, if any.

NUCLEAR CONTINGENCIES

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

OPERATIONAL CONTINGENCIES

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.

Natural Gas Markets Lawsuits

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

Wage and Hours Lawsuit

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

In March 2014, the federal court granted plaintiffs’ motion to conditionally certify the action as a class action. We will continue to defend the case. We are unable to determine a range of potential losses that are reasonably possible of occurring.

6. BENEFIT PLANS

Components of Net Periodic Benefit Cost

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

	Pension Plans Three Months Ended March 31,		Other Postretirement Benefit Plans Three Months Ended March 31,	
	2014	2013	2014	2013
	(in millions)			
Service Cost	$ 18	$ 17	$ 4	$ 6
Interest Cost	55	50	17	18
Expected Return on Plan Assets	(66)	(69)	(28)	(27)
Amortization of Prior Service Cost (Credit)	1	1	(17)	(17)
Amortization of Net Actuarial Loss	31	46	5	16
Net Periodic Benefit Cost (Credit)	$ 39	$ 45	$ (19)	$ (4)

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7. BUSINESS SEGMENTS

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

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 remainder of our activities is presented as Corporate and Other. 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.

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

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)				
Three Months Ended March 31, 2014								
Revenues from:								
External Customers	$ 2,549 (b)	$ 1,161	$ 12	$ 821 (b)	$ 146	$ 10	$ (51)(c)	$ 4,648
Other Operating Segments	37 (b)	54	16	430 (b)	19	16	(572)	-
Total Revenues	$ 2,586	$ 1,215	$ 28	$ 1,251	$ 165	$ 26	$ (623)	$ 4,648
Net Income (Loss)	$ 279	$ 97	$ 24	$ 163	$ 3	$ (5)	$ -	$ 561

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)				
Three Months Ended March 31, 2013								
Revenues from:								
External Customers	$ 2,356	$ 1,090	$ 3	$ 258	$ 128	$ 5	$ (14)(c)	$ 3,826
Other Operating Segments	159	44	5	662	5	13	(888)	-
Total Revenues	$ 2,515	$ 1,134	$ 8	$ 920	$ 133	$ 18	$ (902)	$ 3,826
Net Income (Loss)	$ 181	$ 87	$ 12	$ 85	$ (2)	$ 1	$ -	$ 364

	Vertically	Transmission and	AEP	Generation		Corporate	Reconciling

	Integrated Utilities	Distribution Utilities	Transmission Holdco	& Marketing	AEP River Operations	and Other (a)	Adjustments (d)	Consolidated
	(in millions)							
March 31, 2014								
Total Property, Plant and Equipment	$ 37,923	$ 12,339	$ 1,842	$ 8,302	$ 639	$ 321	$ (272)	$ 61,094
Accumulated Depreciation and Amortization	12,424	3,382	13	3,460	197	176	(88)	19,564
Total Property, Plant and Equipment - Net	$ 25,499	$ 8,957	$ 1,829	$ 4,842	$ 442	$ 145	$ (184)	$ 41,530
Total Assets	$ 32,997	$ 13,899	$ 2,460	$ 6,354	$ 659	$ 20,275	$ (19,606)(e)	$ 57,038

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments (d)	Consolidated
	(in millions)							
December 31, 2013								
Total Property, Plant and Equipment	$ 37,545	$ 12,143	$ 1,636	$ 8,277	$ 638	$ 315	$ (269)	$ 60,285
Accumulated Depreciation and Amortization	12,250	3,342	10	3,409	189	173	(85)	19,288
Total Property, Plant and Equipment - Net	$ 25,295	$ 8,801	$ 1,626	$ 4,868	$ 449	$ 142	$ (184)	$ 40,997
Total Assets	$ 32,791	$ 14,165	$ 2,245	$ 6,426	$ 673	$ 19,645	$ (19,531)(e)	$ 56,414

(a) 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.

(b) Includes the impact of the corporate separation of OPCo’s generation assets and liabilities that took effect December 31, 2013, as well as the impact of the termination of the Interconnection Agreement effective January 1, 2014.
(c) Reconciling Adjustments for External Customers primarily include eliminations as a result of corporate separation.
(d) Includes eliminations due to an intercompany capital lease.
(e) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP’s investments in subsidiary companies.

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

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

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

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume March 31, 2014 (in millions)	Volume December 31, 2013 (in millions)	Unit of Measure
Commodity:			
Power	320	406	MWhs
Coal	4	4	Tons
Natural Gas	123	127	MMBtus
Heating Oil and Gasoline	4	6	Gallons
Interest Rate	$ 192	$ 191	USD
Interest Rate and Foreign Currency	$ 819	$ 820	USD

Fair Value Hedging Strategies

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

Cash Flow Hedging Strategies

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

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

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

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

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON OUR FINANCIAL STATEMENTS

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

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

According to the accounting guidance for "Derivatives and Hedging," we reflect the fair values of our derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, we are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the March 31, 2014 and December 31, 2013 condensed balance sheets, we netted $19 million and $4 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $17 million and $13 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

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

Fair Value of Derivative Instruments
March 31, 2014

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)					
Current Risk Management Assets	$ 442	$ 23	$ 4	$ 469	$ (344)	$ 125
Long-term Risk Management Assets	342	5	-	347	(81)	266
Total Assets	784	28	4	816	(425)	391
Current Risk Management Liabilities	384	16	1	401	(341)	60
Long-term Risk Management Liabilities	205	4	13	222	(85)	137
Total Liabilities	589	20	14	623	(426)	197
Total MTM Derivative Contract Net Assets (Liabilities)	$ 195	$ 8	$ (10)	$ 193	$ 1	$ 194

Fair Value of Derivative Instruments
December 31, 2013

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)

			(in millions)			
Current Risk Management Assets	$ 347	$ 12	$ 4	$ 363	$ (203)	$ 160
Long-term Risk Management Assets	368	3	-	371	(74)	297
Total Assets	715	15	4	734	(277)	457
Current Risk Management Liabilities	292	11	1	304	(214)	90
Long-term Risk Management Liabilities	237	3	15	255	(78)	177
Total Liabilities	529	14	16	559	(292)	267
Total MTM Derivative Contract Net Assets (Liabilities)	$ 186	$ 1	$ (12)	$ 175	$ 15	$ 190

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the condensed balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts primarily include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging." Amounts also include de-designated risk management contracts.
(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The table below presents our activity of derivative risk management contracts for the three months ended March 31, 2014 and 2013:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended March 31, 2014 and 2013

Location of Gain (Loss)	2014	2013
	(in millions)	
Vertically Integrated Utilities Revenues	$ 18	$ 6
Generation & Marketing Revenues	32	16
Regulatory Assets (a)	-	2
Regulatory Liabilities (a)	89	(6)
Total Gain on Risk Management Contracts	$ 139	$ 18

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

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

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

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

Accounting for Fair Value Hedging Strategies

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

We record realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on our condensed statements of income. During the three months ended March 31, 2014, we recognized gains of $2 million on our hedging instruments and offsetting losses of $2 million on our long-term debt. During the three months ended March 31, 2013, we recognized losses of $1 million on our hedging instruments and offsetting gains of $1 million on our long-term debt. During the three months ended March 31, 2014 and 2013, hedge ineffectiveness was immaterial.

Accounting for Cash Flow Hedging Strategies

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

Realized gains and losses on derivative contracts for the purchase and sale of power, coal and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on our condensed statements of income, or in Regulatory Assets or Regulatory Liabilities on our condensed balance sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2014 and 2013, we designated power, coal and natural gas derivatives as cash flow hedges.

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

We reclassify gains and losses on interest rate derivative hedges related to our debt financings from Accumulated Other Comprehensive Income (Loss) on our condensed balance sheets into Interest Expense on our condensed statements of income in those periods in which hedged interest payments occur. During the three months ended March 31, 2014 and 2013, we designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to our foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on our condensed balance sheets into Depreciation and Amortization expense on our condensed statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three months ended March 31, 2014 and 2013, we did not designate any foreign currency derivatives as cash flow hedges.

During the three months ended March 31, 2014 and 2013, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

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

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

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

	Commodity	Interest Rate and Foreign Currency (in millions)	Total
Hedging Assets (a)	$ 13	$ -	$ 13
Hedging Liabilities (a)	5	2	7
AOCI Gain (Loss) Net of Tax	4	(22)	(18)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	3	(4)	(1)

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

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

(a)

Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the condensed balance sheets.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of March 31, 2014, the maximum length of time that we are hedging (with contracts subject to the accounting guidance for “Derivatives and Hedging”) our exposure to variability in future cash flows related to forecasted transactions was 41 months.

Credit Risk

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

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

Collateral Triggering Events

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

	March 31, 2014	December 31, 2013
	(in millions)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 2	$ 3
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post	144	33
Amount Attributable to RTO and ISO Activities	38	28

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

	March 31, 2014	December 31, 2013
	(in millions)	

Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$	225	$	293
Amount of Cash Collateral Posted		-		1
Additional Settlement Liability if Cross Default Provision is Triggered		177		235

9. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

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

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

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

Assets in the nuclear trusts, Cash and Cash Equivalents and Other Temporary Investments are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities and cash equivalents funds. Fixed income securities do not trade on an exchange and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

Fair Value Measurements of Long-term Debt

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

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

	March 31, 2014		December 31, 2013	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 18,087	$ 19,738	$ 18,377	$ 19,672

Fair Value Measurements of Other Temporary Investments

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

The following is a summary of Other Temporary Investments:

	March 31, 2014			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)			
Restricted Cash (a)	$ 206	$ -	$ -	$ 206
Fixed Income Securities:				
Mutual Funds	80	-	-	80
Equity Securities - Mutual Funds	13	11	-	24
Total Other Temporary Investments	$ 299	$ 11	$ -	$ 310

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

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

The following table provides the activity for our fixed income and equity securities within Other Temporary Investments for the three months ended March 31, 2014 and 2013:

	Three Months Ended March 31, 2014	2013
	(in millions)	
Proceeds from Investment Sales	$ -	$ -
Purchases of Investments	1	11
Gross Realized Gains on Investment Sales	-	-
Gross Realized Losses on Investment Sales	-	-

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

For details of the reasons for changes in Securities Available for Sale included in Accumulated Other Comprehensive Income (Loss) for the three months ended March 31, 2014 and 2013, see Note 3.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

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

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

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

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments for investments in both fixed income and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the equity and fixed income investments held in these trusts and generally intends to sell fixed income securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. I&M records unrealized gains and other-than-temporary impairments from securities in the trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. The trust assets are recorded by jurisdiction and may not be used for another jurisdiction’s liabilities. Regulatory approval is required to withdraw decommissioning funds.

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

	March 31, 2014			December 31, 2013		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 12	$ -	$ -	$ 19	$ -	$ -
Fixed Income Securities:						
United States Government	606	31	(4)	609	26	(4)
Corporate Debt	43	4	(1)	37	2	(1)
State and Local Government	281	1	-	255	1	-
Subtotal Fixed Income Securities	930	36	(5)	901	29	(5)
Equity Securities - Domestic	1,020	514	(80)	1,012	506	(82)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,962	$ 550	$ (85)	$ 1,932	$ 535	$ (87)

The following table provides the securities activity within the decommissioning and SNF trusts for the three months ended March 31, 2014 and 2013:

	Three Months Ended March 31,	
	2014	2013
	(in millions)	
Proceeds from Investment Sales	$ 148	$ 168
Purchases of Investments	164	185
Gross Realized Gains on Investment Sales	8	3
Gross Realized Losses on Investment Sales	1	2

The adjusted cost of fixed income securities was $894 million and $872 million as of March 31, 2014 and December 31, 2013, respectively. The adjusted cost of equity securities was $506 million and $506 million as of March 31, 2014 and December 31, 2013, respectively.

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

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 82
1 year – 5 years	386

5 years – 10 years		193
After 10 years		269
Total	$	930

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Fair Value Measurements of Financial Assets and Liabilities

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

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 16	$ 1	$ -	$ 275	$ 292
Other Temporary Investments					
Restricted Cash (a)	187	7	-	12	206
Fixed Income Securities:					
Mutual Funds	80	-	-	-	80
Equity Securities - Mutual Funds (b)	24	-	-	-	24
Total Other Temporary Investments	291	7	-	12	310
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	20	586	128	(364)	370
Cash Flow Hedges:					
Commodity Hedges (c)	-	21	2	(10)	13
Fair Value Hedges	-	2	-	2	4
De-designated Risk Management Contracts (e)	-	-	-	4	4
Total Risk Management Assets	20	609	130	(368)	391
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	3	-	-	9	12
Fixed Income Securities:					
United States Government	-	606	-	-	606
Corporate Debt	-	43	-	-	43
State and Local Government	-	281	-	-	281
Subtotal Fixed Income Securities	-	930	-	-	930
Equity Securities - Domestic (b)	1,020	-	-	-	1,020
Total Spent Nuclear Fuel and Decommissioning Trusts	1,023	930	-	9	1,962
Total Assets	$ 1,350	$ 1,547	$ 130	$ (72)	$ 2,955

Liabilities:

Risk Management Liabilities										
Risk Management Commodity Contracts (c) (d)	$	30	$	485	$	25	$	(362)	$	178
Cash Flow Hedges:										
Commodity Hedges (c)		-		15		-		(10)		5
Interest Rate/Foreign Currency Hedges		-		2		-		-		2
Fair Value Hedges		-		10		-		2		12
Total Risk Management Liabilities	$	30	$	512	$	25	$	(370)	$	197

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

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

Fair Value Hedges		-		11		-		3		14
Total Risk Management Liabilities	$	30	$	499	$	25	$	(287)	$	267

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.
(b) Amounts represent publicly traded equity securities and equity-based mutual funds.
(c) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(d) The March 31, 2014 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $2 million in 2014, $(11) million in periods 2015-2017 and $(1) million in periods 2018-2019; Level 2 matures $32 million in 2014, $56 million in periods 2015-2017, $8 million in periods 2018-2019 and $5 million in periods 2020-2030; Level 3 matures $15 million in 2014, $49 million in periods 2015-2017, $16 million in periods 2018-2019 and $23 million in periods 2020-2030. Risk management commodity contracts are substantially comprised of power contracts.
(e) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.
(f) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 1 amounts primarily represent investments in money market funds.
(g) The December 31, 2013 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $4 million in 2014, $(11) million in periods 2015-2017 and $(1) million in periods 2018-2019; Level 2 matures $25 million in 2014, $37 million in periods 2015-2017, $7 million in periods 2018-2019 and $5 million in periods 2020-2030; Level 3 matures $27 million in 2014, $60 million in periods 2015-2017, $14 million in periods 2018-2019 and $19 million in periods 2020-2030. Risk management commodity contracts are substantially comprised of power contracts.

There were no transfers between Level 1 and Level 2 during the three months ended March 31, 2014 and 2013.

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

Three Months Ended March 31, 2014		Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2013	$	117
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		84
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		(10)
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		9
Purchases, Issuances and Settlements (c)		(100)
Transfers into Level 3 (d) (e)		(4)
Transfers out of Level 3 (e) (f)		(2)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		11
Balance as of March 31, 2014	$	105

Three Months Ended March 31, 2013		Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2012	$	86
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		(4)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		(5)
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		1
Purchases, Issuances and Settlements (c)		(6)
Transfers into Level 3 (d) (e)		6
Transfers out of Level 3 (e) (f)		-
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		(2)
Balance as of March 31, 2013	$	76

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

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

Significant Unobservable Inputs
March 31, 2014

	Fair Value				Valuation	Significant	Input/Range			
	Assets (in millions)		Liabilities		Technique	Significant Unobservable Input	Low		High	
Energy Contracts	$	116	$	23	Discounted Cash Flow	Forward Market Price (a)	$	1.45	$	131.46
						Counterparty Credit Risk (b)	315			
FTRs		14		2	Discounted Cash Flow	Forward Market Price (a)		(5.05)		9.17
Total	$	130	$	25						

Significant Unobservable Inputs
December 31, 2013

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

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

10. INCOME TAXES

AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

The IRS examination of years 2009 and 2010 started in October 2011 and was completed in the second quarter of 2013. The IRS examination of years 2011 and 2012 started in April 2014. Although the outcome of tax audits is uncertain, in our opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, we accrue interest on these uncertain tax positions. We are not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

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

11. FINANCING ACTIVITIES

Long-term Debt

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

Type of Debt	March 31, 2014	December 31, 2013
	(in millions)	
Senior Unsecured Notes	$ 11,571	$ 11,799
Pollution Control Bonds	1,932	1,932
Notes Payable	342	369
Securitization Bonds	2,574	2,686
Spent Nuclear Fuel Obligation (a)	265	265
Other Long-term Debt	1,434	1,360
Fair Value of Interest Rate Hedges	(7)	(9)
Unamortized Discount, Net	(24)	(25)
Total Long-term Debt Outstanding	18,087	18,377
Long-term Debt Due Within One Year	1,612	1,549
Long-term Debt	$ 16,475	$ 16,828

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M, a nuclear licensee, has an obligation to the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets related to this obligation were $309 million and $309 million as of March 31, 2014 and December 31, 2013, respectively, and are included in Spent Nuclear Fuel and Decommissioning Trusts on our condensed balance sheets.

Long-term debt and other securities issued, retired and principal payments made during the first three months of 2014 are shown in the tables below:

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
Issuances:		(in millions)	(%)	
PSO	Other Long-term Debt	$ 50	Variable	2016
Non-Registrant:				
Transource Missouri	Other Long-term Debt	27	Variable	2018
Total Issuances		$ 77 (a)		

Company	Type of Debt	Principal Amount Paid	Interest Rate	Due Date
Retirements and Principal Payments:		(in millions)	(%)	
I&M	Notes Payable	$ 5	Variable	2016
I&M	Notes Payable	4	2.12	2016

I&M	Notes Payable		5	Variable	2016
I&M	Notes Payable		10	Variable	2017
I&M	Other Long-term Debt		2	Variable	2015
OPCo	Senior Unsecured Notes		225	4.85	2014
SWEPCo	Notes Payable		2	4.58	2032
Non-Registrant:					
AEGCo	Senior Unsecured Notes		4	6.33	2037
AEP Subsidiaries	Notes Payable		1	Variable	2017
TCC	Securitization Bonds		72	5.09	2015
TCC	Securitization Bonds		40	6.25	2016
Total Retirements and Principal Payments		$	370		

(a) Amount indicated on the statement of cash flows is net of issuance costs and premium or discount and will not tie to the total issuances.

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

As of March 31, 2014, trustees held on our behalf, $500 million of our reacquired Pollution Control Bonds.

Dividend Restrictions

Parent Restrictions

The holders of our common stock are entitled to receive the dividends declared by our Board of Directors provided funds are legally available for such dividends. Our income primarily derives from our common stock equity in the earnings of our utility subsidiaries.

Pursuant to the leverage restrictions in our credit agreements, we must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization of the company distributing the dividend. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements. None of AEP’s retained earnings were restricted for the purpose of the payment of dividends.

Utility Subsidiaries’ Restrictions

Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends. Specifically, several of our public utility subsidiaries have credit agreements that contain a covenant that limits their debt to capitalization ratio to 67.5%.

The Federal Power Act prohibits the utility subsidiaries from participating “in the making or paying of any dividends of such public utility from any funds properly included in capital account.” The term “capital account” is not defined in the Federal Power Act or its regulations. Management understands “capital account” to mean the book value of the common stock. This restriction does not limit the ability of the utility subsidiaries to pay dividends out of retained earnings.

Short-term Debt

Our outstanding short-term debt was as follows:

	March 31, 2014		December 31, 2013	
Type of Debt	Outstanding Amount (in millions)	Interest Rate (a)	Outstanding Amount (in millions)	Interest Rate (a)
Securitized Debt for Receivables (b)	$ 700	0.24 %	$ 700	0.23 %
Commercial Paper	632	0.31 %	57	0.29 %
Total Short-term Debt	$ 1,332		$ 757	

(a) Weighted average rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.

Credit Facilities

For an additional discussion of credit facilities, see “Letters of Credit” section of Note 5.

Securitized Accounts Receivable – AEP Credit

AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the receivables AEP Credit acquires from affiliated utility subsidiaries. AEP Credit continues to service the receivables. These securitized transactions allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables and accelerate AEP Credit's cash collections.

Our receivables securitization agreement provides a commitment of $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.

Accounts receivable information for AEP Credit is as follows:

	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013
	(dollars in millions)	
Effective Interest Rates on Securitization of Accounts Receivable	0.24 %	0.23 %
Net Uncollectible Accounts Receivable Written Off	$ 8	$ 7

	March 31, 2014	December 31, 2013
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 997	$ 929
Total Principal Outstanding	700	700
Delinquent Securitized Accounts Receivable	55	45
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	17	16
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	278	331

Customer accounts receivable retained and securitized for our operating companies are managed by AEP Credit. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

12. VARIABLE INTEREST ENTITIES

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether we are the primary beneficiary of a VIE, we consider factors such as equity at risk, the amount of the VIE's variability we absorb, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. We believe that significant assumptions and judgments were applied consistently.

We are the primary beneficiary of Sabine, DCC Fuel, AEP Credit, Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, a protected cell of EIS and Transource Energy. In addition, we have not provided material financial or other support to Sabine, DCC Fuel, AEP Credit, Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, our protected cell of EIS and Transource Energy that was not previously contractually required. We hold a significant variable interest in DHLC and Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series).

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the three months ended March 31, 2014 and 2013 were $39 million and $44 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on the condensed balance sheets.

I&M has nuclear fuel lease agreements with DCC Fuel II LLC, DCC Fuel IV LLC, DCC Fuel V LLC and DCC Fuel VI LLC (collectively DCC Fuel). DCC Fuel was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the three months ended March 31, 2014 and 2013 were $25 million and $26 million, respectively. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the respective lease terms, which do not exceed 54 months. Based on our control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. In October 2013, the lease agreements ended for DCC Fuel LLC and DCC Fuel III LLC. See the tables below for the classification of DCC Fuel's assets and liabilities on the condensed balance sheets.

AEP Credit is a wholly-owned subsidiary of AEP. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides a minimum of 5% equity and up to 20% of AEP Credit's short-term borrowing needs in excess of third party financings. Any third party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on our control of AEP Credit, management concluded that we are the primary beneficiary and are required to consolidate AEP Credit. See the tables below for the classification of AEP Credit's assets and liabilities on the condensed balance sheets. See "Securitized Accounts Receivables – AEP Credit" section of Note 11.

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. Management has concluded that TCC is the primary beneficiary of Transition Funding because TCC has the power to direct the most significant activities of the VIE and TCC's equity interest could potentially be significant. Therefore, TCC is required to consolidate Transition Funding. The securitized bonds totaled $2 billion and $2 billion as of March 31, 2014 and December 31, 2013, respectively. Transition Funding has securitized transition assets of $1.8 billion and $1.9 billion as of March 31, 2014 and December 31, 2013, respectively. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from TCC under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to TCC or any other AEP entity. TCC acts as the servicer for Transition Funding's securitized transition assets and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Transition Funding's assets and liabilities on the condensed balance sheets.

Ohio Phase-in-Recovery Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Phase-in recovery property. Management has concluded that OPCo is the primary beneficiary of Ohio Phase-in-Recovery Funding because OPCo has the power to direct the most significant activities of the VIE and OPCo's equity interest could potentially be significant. Therefore, OPCo is required to consolidate Ohio Phase-in-Recovery Funding. The securitized bonds totaled $267 million and $267 million as of March 31, 2014 and December 31, 2013, respectively. Ohio Phase-in-Recovery Funding has securitized assets of $127 million and $132 million as of March 31, 2014 and December 31, 2013, respectively. The phase-in recovery property represents the right to impose and collect Ohio deferred distribution charges from customers receiving electric transmission and distribution service from OPCo under a recovery mechanism approved by the PUCO. In August 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to OPCo or any other AEP entity. OPCo acts as the servicer for Ohio Phase-in-Recovery Funding's securitized assets and remits all related amounts collected from customers to Ohio Phase-in-Recovery Funding for interest and principal payments on the securitization bonds and related costs. See the table below for the classification of Ohio Phase-in-Recovery Funding's assets and liabilities on the condensed balance sheets.

Appalachian Consumer Rate Relief Funding was formed for the sole purpose of issuing and servicing securitization bonds related to APCo's under-recovered ENEC deferral balance. Management has concluded that APCo is the primary beneficiary of Appalachian Consumer Rate Relief Funding because APCo has the power to direct the most significant activities of the VIE and APCo's equity interest could potentially be significant. Therefore, APCo is required to consolidate Appalachian Consumer Rate Relief Funding. The securitized bonds totaled $380 million and

$380 million as of March 31, 2014 and December 31, 2013, respectively. Appalachian Consumer Rate Relief Funding has securitized assets of $365 million and $369 million as of March 31, 2014 and December 31, 2013, respectively. The phase-in recovery property represents the right to impose and collect West Virginia deferred generation charges from customers receiving electric transmission, distribution and generation service from APCo under a recovery mechanism approved by the WVPSC. In November 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to APCo or any other AEP entity. APCo acts as the servicer for Appalachian Consumer Rate Relief Funding's securitized assets and remits all related amounts collected from customers to Appalachian Consumer Rate Relief Funding for interest and principal payments on the securitization bonds and related costs. See the table below for the classification of Appalachian Consumer Rate Relief Funding's assets and liabilities on the condensed balance sheets.

The securitized bonds of Transition Funding, Ohio Phase-in-Recovery Funding and Appalachian Consumer Rate Relief Funding are included in current and long-term debt on the condensed balance sheets. The securitized assets of Transition Funding, Ohio Phase-in-Recovery Funding and Appalachian Consumer Rate Relief Funding are included in securitized assets on the condensed balance sheets.

Our subsidiaries participate in one protected cell of EIS for approximately ten lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell’s only participant, but allows certain third parties access to this insurance. Our subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on our control and the structure of the protected cell and EIS, management concluded that we are the primary beneficiary of the protected cell and are required to consolidate EIS. Our insurance premium expense to the protected cell for the three months ended March 31, 2014 and 2013 was $16 million and $15 million, respectively. See the tables below for the classification of the protected cell’s assets and liabilities on the condensed balance sheets. The amount reported as equity is the protected cell’s policy holders’ surplus.

Transource Energy was formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates. AEP has equity and voting ownership of 86.5% with the other owner having 13.5% interest. Management has concluded that Transource Energy is a VIE and that AEP is the primary beneficiary because AEP has the power to direct the most significant activities of the entity. AEP's equity interest could potentially be significant. Therefore, AEP is required to consolidate Transource Energy. In January 2014, Transource Missouri acquired transmission assets from the non-controlling owner and issued debt and received capital contributions to fund the acquisition. The majority of Transource Energy’s activity resulted from the asset acquisition, debt issuance and capital contribution. See the table below for the classification of Transource Energy’s assets and liabilities on the condensed balance sheets.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
March 31, 2014
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	AEP Credit	TCC Transition Funding	OPCo Ohio Phase-in-Recovery Funding	APCo Appalachian Consumer Rate Relief Funding	Protected Cell of EIS	Transource Energy
ASSETS								
Current Assets	$ 62	$ 109	$ 1,004	$ 166	$ 36	$ 16	$ 152	$ 4
Net Property, Plant and Equipment	154	129	-	-	-	-	-	57
Other Noncurrent Assets	50	45	-	1,861 (a)	242 (b)	374 (c)	3	5
Total Assets	$ 266	$ 283	$ 1,004	$ 2,027	$ 278	$ 390	$ 155	$ 66
LIABILITIES AND EQUITY								
Current Liabilities	$ 29	$ 100	$ 894	$ 304	$ 60	$ 28	$ 48	$ 18
Noncurrent Liabilities	236	183	1	1,705	217	360	67	28
Equity	1	-	109	18	1	2	40	20
Total Liabilities and Equity	$ 266	$ 283	$ 1,004	$ 2,027	$ 278	$ 390	$ 155	$ 66

(a) Includes an intercompany item eliminated in consolidation of $81 million.
(b) Includes an intercompany item eliminated in consolidation of $112 million.
(c) Includes an intercompany item eliminated in consolidation of $4 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2013
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	AEP Credit	TCC Transition Funding	OPCo Ohio Phase-in-Recovery Funding	APCo Appalachian Consumer Rate Relief Funding	Protected Cell of EIS

ASSETS																
Current Assets	$	67	$	118	$	935	$	232		$	23		$	6	$	143
Net Property, Plant and Equipment		157		157		-		-			-			-		-
Other Noncurrent Assets		51		60		1		1,918	(a)		252	(b)		378	(c)	3
Total Assets	$	275	$	335	$	936	$	2,150		$	275		$	384	$	146
LIABILITIES AND EQUITY																
Current Liabilities	$	33	$	108	$	827	$	312		$	37		$	14	$	39
Noncurrent Liabilities		242		227		1		1,820			237			368		66
Equity		-		-		108		18			1			2		41
Total Liabilities and Equity	$	275	$	335	$	936	$	2,150		$	275		$	384	$	146

(a) Includes an intercompany item eliminated in consolidation of $82 million.
(b) Includes an intercompany item eliminated in consolidation of $116 million.
(c) Includes an intercompany item eliminated in consolidation of $4 million.

DHLC is a mining operator that sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and voting rights equally. Each entity guarantees 50% of DHLC's debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. SWEPCo's total billings from DHLC for the three months ended March 31, 2014 and 2013 were $2 million and $18 million, respectively. We are not required to consolidate DHLC as we are not the primary beneficiary, although we hold a significant variable interest in DHLC. Our equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on the condensed balance sheets.

Our investment in DHLC was:

	March 31, 2014		December 31, 2013	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from SWEPCo	$ 8	$ 8	$ 8	$ 8
Retained Earnings	2	2	1	1
SWEPCo's Guarantee of Debt	-	85	-	61
Total Investment in DHLC	$ 10	$ 95	$ 9	$ 70

We and FirstEnergy Corp. (FirstEnergy) have a joint venture in Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct, through its operating companies, a high-voltage transmission line project in the PJM region. PATH consists of the "West Virginia Series (PATH-WV)," owned equally by subsidiaries of FirstEnergy and AEP, and the "Allegheny Series" which is 100% owned by a subsidiary of FirstEnergy. Provisions exist within the PATH-WV agreement that make it a VIE. The "Allegheny Series" is not considered a VIE. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant variable interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on our condensed balance sheets. We and FirstEnergy share the returns and losses equally in PATH-WV. Our subsidiaries and FirstEnergy's subsidiaries provide services to the PATH companies through service agreements. The entities recover costs through regulated rates.

In August 2012, the PJM board cancelled the PATH Project, our transmission joint venture with FirstEnergy, and removed it from the 2012 Regional Transmission Expansion Plan. In September 2012, the PATH Project companies submitted an application to the FERC requesting authority to recover prudently-incurred costs associated with the PATH Project. In November 2012, the FERC issued an order accepting the PATH Project's abandonment cost recovery application, subject to settlement procedures and hearing. The parties to the case have been unable to reach a settlement agreement. In March 2014, the settlement judge recommended termination of the settlement proceedings and this case is expected to proceed to a hearing.

Our investment in PATH-WV was:

	March 31, 2014		December 31, 2013	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			

Capital Contribution from AEP	$	19	$	19	$	19	$	19
Retained Earnings		6		6		6		6
Total Investment in PATH-WV	$	25	$	25	$	25	$	25

As of March 31, 2014, our $25 million investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the condensed balance sheet. If we cannot ultimately recover our investment related to PATH-WV, it could reduce future net income and cash flows.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

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APPALACHIAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Regulatory Activity

Plant Transfer

In March 2014, APCo and WPCo filed a request with the WVPSC for approval to transfer at net book value to WPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity presently owned by AGR. In April 2014, APCo and WPCo filed testimony that supported their request and proposed a base rate surcharge of $113 million, to be offset by an equal reduction in the ENEC revenues, to be effective upon the transfer of the Mitchell Plant to WPCo. Management anticipates an order related to the proposed plant transfer will be issued in the fourth quarter of 2014. In April 2014, APCo and WPCo also filed a request with the FERC for approval to transfer AGR's one-half interest in the Mitchell Plant to WPCo. Upon transfer of the Mitchell Plant to WPCo, WPCo will no longer purchase power from AGR.

WPCo Merger with APCo

In December 2011, APCo and WPCo filed an application with the WVPSC requesting authority to merge WPCo into APCo. In December 2012, APCo and WPCo filed merger applications with the Virginia SCC and the FERC. In April 2013, the FERC approved the merger. Also in December 2012, APCo and WPCo filed requests with the Virginia SCC and the WVPSC for approval to transfer at net book value to APCo a two-thirds interest in Amos Plant, Unit 3 and a one-half interest in the Mitchell Plant. In July 2013, the Virginia SCC approved the merger of WPCo into APCo and the transfer of the two-thirds interest in the Amos Plant, Unit 3 to APCo but denied the proposed transfer of the one-half interest in the Mitchell Plant to APCo. In December 2013, the WVPSC issued an order that deferred ruling on the merger of WPCo into APCo. The feasibility of the merger remains under review. See the "WPCo Merger with APCo" section of APCo Rate Matters in 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.

Litigation and Environmental Issues

In the ordinary course of business, APCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 3 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies in the 2013 Annual Report. Also, see Note 4 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 132. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 186 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2014	2013
	(in millions of KWhs)	
Retail:		
Residential	4,362	4,001
Commercial	1,780	1,742
Industrial	2,492	2,588
Miscellaneous	222	217
Total Retail	8,856	8,548
Wholesale	1,071	2,281
Total KWhs	9,927	10,829

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.

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31, 2014	2013
	(in degree days)	
Actual - Heating (a)	1,715	1,404
Normal - Heating (b)	1,311	1,312
Actual - Cooling (c)	-	-
Normal - Cooling (b)	7	7

(a) Eastern 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 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
(in millions)

First Quarter of 2013	$	71
Changes in Gross Margin:		
Retail Margins		35
Off-system Sales		1
Transmission Revenues		4
Other Revenues		11
Total Change in Gross Margin		51
Changes in Expenses and Other:		
Other Operation and Maintenance		25
Depreciation and Amortization		(17)
Taxes Other Than Income Taxes		(4)
Carrying Costs Income		(2)
Other Income		1
Interest Expense		(4)
Total Change in Expenses and Other		(1)
Income Tax Expense		(19)
First Quarter of 2014	$	102

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 $35 million primarily due to the following:
  · A $27 million increase primarily due to a 22% increase in heating degree days.
  · A $26 million increase primarily due to changes in rates in West Virginia. Of these increases, $10 million relate to riders/trackers which have corresponding increases in other expense items below.
  · A $19 million decrease in capacity settlement due to the termination of the Interconnection Agreement.
  · A $6 million decrease in other variable electric generation expenses.

  These increases were partially offset by:
  · A $13 million increase in PJM expenses.
  · A $10 million decrease due to increased sales of renewable energy credits in 2014. This decrease is offset in Other Revenues.
  · A $7 million increase in expense due to the timing of fuel recovery.
  · A $4 million decrease primarily due to lower industrial usage.

· Transmission Revenues increased $4 million primarily due to increased investments in the PJM region. These increased revenues are offset in Other Operation and Maintenance expenses below.

·

Other Revenues increased $11 million primarily due to increased sales of renewable energy credits. This increase in revenues is mainly offset in Retail Margins in fuel recovery.

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

- Other Operation and Maintenance expenses decreased $25 million primarily due to the following:
  - A $30 million write-off in the first quarter of 2013 of previously deferred Virginia storm costs resulting from the 2013 enactment of a Virginia law.
  - A $15 million decrease in distribution maintenance expense primarily due to the January 2013 snow storm.

  These decreases were partially offset by:
  - A $6 million increase in transmission expenses due to increased investment in the PJM region. These expenses are partially offset in Transmission Revenues.
  - A $5 million increase in steam operation and maintenance expenses.
  - A $2 million increase in employee-related expenses.
- Depreciation and Amortization expenses increased $17 million primarily due to:
  - An $11 million increase primarily due to higher depreciable base.
  - A $3 million increase due to over-recovery of revenues for securitization.
- Taxes Other Than Income Taxes expenses increased $4 million primarily due to:
  - A $2 million increase in state business occupation tax and state minimum tax accruals.
  - A $1 million increase in real and personal property taxes amortization.
- Interest Expense increased $4 million primarily due to the issuance of securitization bonds and the assumption of debt related to corporate separation.
- Income Tax Expense increased $19 million primarily due to an increase in pretax book income.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” 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 and pension and other postretirement benefits.

See the “Accounting Pronouncements” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” beginning on page 186 for a discussion of accounting pronouncements.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013
REVENUES		
Electric Generation, Transmission and Distribution	$ 866,457	$ 872,732
Sales to AEP Affiliates	44,914	76,860
Other Revenues	2,020	1,902
TOTAL REVENUES	913,391	951,494
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	230,737	204,939
Purchased Electricity for Resale	168,991	65,456
Purchased Electricity from AEP Affiliates	4,662	222,942
Other Operation	93,538	78,908
Maintenance	60,090	99,386
Depreciation and Amortization	104,586	87,903
Taxes Other Than Income Taxes	30,777	27,400
TOTAL EXPENSES	693,381	786,934
OPERATING INCOME	220,010	164,560
Other Income (Expense):		
Interest Income	401	331
Carrying Costs Income (Expense)	(1,875)	103
Allowance for Equity Funds Used During Construction	1,235	770
Interest Expense	(51,672)	(48,204)
INCOME BEFORE INCOME TAX EXPENSE	168,099	117,560
Income Tax Expense	66,248	47,012
NET INCOME	$ 101,851	$ 70,548

The common stock of APCo is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31,	
	2014	2013
Net Income	$ 101,851	$70,548
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES		
Cash Flow Hedges, Net of Tax of $132 and $677 in 2014 and 2013, Respectively	246	1,258
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $179 and $193 in 2014 and 2013, Respectively	(333)	358
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(87)	1,616
TOTAL COMPREHENSIVE INCOME	$ 101,764	$72,164

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2012	$ 260,458	$ 1,573,752	$ 1,248,250	$ (29,898)	$ 3,052,562
Common Stock Dividends			(50,000)		(50,000)
Net Income			70,548		70,548
Other Comprehensive Income				1,616	1,616
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2013	$ 260,458	$ 1,573,752	$ 1,268,798	$ (28,282)	$ 3,074,726
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2013	$ 260,458	$ 1,809,562	$ 1,156,461	$ 2,951	$ 3,229,432
Common Stock Dividends			(20,000)		(20,000)
Net Income			101,851		101,851
Other Comprehensive Loss				(87)	(87)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2014	$ 260,458	$ 1,809,562	$ 1,238,312	$ 2,864	$ 3,311,196

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2014 and December 31, 2013
(in thousands)
(Unaudited)

	March 31, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$ 4,758	$ 2,745
Advances to Affiliates	245,516	92,485
Accounts Receivable:		
Customers	150,954	142,010
Affiliated Companies	72,283	113,793
Accrued Unbilled Revenues	46,631	55,930
Miscellaneous	472	412
Allowance for Uncollectible Accounts	(3,517)	(2,443)
Total Accounts Receivable	266,823	309,702
Fuel	103,983	191,811
Materials and Supplies	128,614	128,843
Risk Management Assets	15,972	21,171
Regulatory Asset for Under-Recovered Fuel Costs	79,498	39,811
Prepayments and Other Current Assets	33,677	16,472
TOTAL CURRENT ASSETS	878,841	803,040
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,752,422	6,745,172
Transmission	2,173,839	2,160,660
Distribution	3,161,917	3,139,150
Other Property, Plant and Equipment	365,750	357,517
Construction Work in Progress	217,713	184,701
Total Property, Plant and Equipment	12,671,641	12,587,200
Accumulated Depreciation and Amortization	3,679,394	3,617,990
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	8,992,247	8,969,210
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,006,426	1,003,890
Securitized Assets	364,984	369,355
Long-term Risk Management Assets	14,013	16,948
Deferred Charges and Other Noncurrent Assets	157,592	148,205
TOTAL OTHER NONCURRENT ASSETS	1,543,015	1,538,398
TOTAL ASSETS	$ 11,414,103	$ 11,310,648

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

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APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2014 and December 31, 2013
(Unaudited)

	March 31, 2014	December 31, 2013
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 188,773	$ 169,184
Affiliated Companies	87,447	120,789
Long-term Debt Due Within One Year – Nonaffiliated	553,399	342,360
Risk Management Liabilities	4,636	8,892
Customer Deposits	69,180	66,040
Deferred Income Taxes	12,208	6,899
Accrued Taxes	115,557	114,699
Accrued Interest	62,397	51,899
Regulatory Liability for Over-Recovered Fuel Costs	45,144	107,048
Other Current Liabilities	76,445	97,566
TOTAL CURRENT LIABILITIES	1,215,186	1,085,376
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,555,117	3,765,997
Long-term Debt – Affiliated	86,000	86,000
Long-term Risk Management Liabilities	7,929	10,241
Deferred Income Taxes	2,297,662	2,232,441
Regulatory Liabilities and Deferred Investment Tax Credits	648,895	631,225
Employee Benefits and Pension Obligations	105,927	82,264
Deferred Credits and Other Noncurrent Liabilities	186,191	187,672
TOTAL NONCURRENT LIABILITIES	6,887,721	6,995,840
TOTAL LIABILITIES	8,102,907	8,081,216
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER’S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260,458	260,458
Paid-in Capital	1,809,562	1,809,562
Retained Earnings	1,238,312	1,156,461
Accumulated Other Comprehensive Income (Loss)	2,864	2,951
TOTAL COMMON SHAREHOLDER’S EQUITY	3,311,196	3,229,432
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 11,414,103	$ 11,310,648

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014	2013
OPERATING ACTIVITIES		
Net Income	$ 101,851	$ 70,548
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	104,586	87,903
Deferred Income Taxes	65,690	17,185
Carrying Costs Income	1,875	(103)
Allowance for Equity Funds Used During Construction	(1,235)	(770)
Mark-to-Market of Risk Management Contracts	1,625	9,404
Fuel Over/Under-Recovery, Net	(102,051)	20,135
Change in Other Noncurrent Assets	4,959	28,314
Change in Other Noncurrent Liabilities	7,799	5,634
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	41,382	7,238
Fuel, Materials and Supplies	88,057	(8,726)
Accounts Payable	(4,314)	(20,597)
Accrued Taxes, Net	929	30,197
Other Current Assets	(7,276)	642
Other Current Liabilities	(6,707)	(10,917)
Net Cash Flows from Operating Activities	297,170	236,087
INVESTING ACTIVITIES		
Construction Expenditures	(112,824)	(110,552)
Change in Advances to Affiliates, Net	(153,031)	(179)
Other Investing Activities	(8,677)	(179)
Net Cash Flows Used for Investing Activities	(274,532)	(110,910)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	(45)	(258)
Change in Advances from Affiliates, Net	-	(77,314)
Retirement of Long-term Debt – Nonaffiliated	(8)	(7)
Principal Payments for Capital Lease Obligations	(1,559)	(1,238)
Dividends Paid on Common Stock	(20,000)	(50,000)
Other Financing Activities	987	1,320
Net Cash Flows Used for Financing Activities	(20,625)	(127,497)
Net Increase (Decrease) in Cash and Cash Equivalents	2,013	(2,320)
Cash and Cash Equivalents at Beginning of Period	2,745	3,576
Cash and Cash Equivalents at End of Period	$ 4,758	$ 1,256

SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	39,431	$	31,018
Net Cash Paid (Received) for Income Taxes		-		231
Noncash Acquisitions Under Capital Leases		2,657		1,548
Construction Expenditures Included in Current Liabilities as of March 31,		38,972		35,733

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

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APPALACHIAN POWER COMPANY AND SUBSIDIARIES
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF
REGISTRANT SUBSIDIARIES

The condensed notes to APCo's condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to APCo.

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Regulatory Activity

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 and Environmental Issues

In the ordinary course of business, I&M is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 3 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies in the 2013 Annual Report. Also, see Note 4 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 132. 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 the motion to transfer this case to the U.S. District Court for the Southern District of Ohio. AEGCo's and I&M's motion to dismiss the case, filed in October 2013, remains pending. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 186 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

		Three Months Ended March 31, 2014	2013
		(in millions of KWhs)	
Retail:			
	Residential	1,905	1,726
	Commercial	1,221	1,188
	Industrial	1,805	1,813
	Miscellaneous	20	20
Total Retail		4,951	4,747
Wholesale		5,296	2,580
Total KWhs		10,247	7,327

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.

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31, 2014	2013
	(in degree days)	
Actual - Heating (a)	2,972	2,287
Normal - Heating (b)	2,149	2,155
Actual - Cooling (c)	-	-
Normal - Cooling (b)	2	2

(a) Eastern 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 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
(in millions)

First Quarter of 2013	$	43
Changes in Gross Margin:		
Retail Margins		27
FERC Municipals and Cooperatives		10
Off-system Sales		47
Transmission Revenues		2
Other Revenues		(14)
Total Change in Gross Margin		72
Changes in Expenses and Other:		
Other Operation and Maintenance		1
Depreciation and Amortization		(9)
Taxes Other Than Income Taxes		1
Other Income		(3)
Interest Expense		(1)
Total Change in Expenses and Other		(11)
Income Tax Expense		(17)
First Quarter of 2014	$	87

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 $27 million primarily due to the following:
  · A $22 million increase primarily due to a rate increase in Indiana effective March 2013.
  · A $13 million increase in weather-related usage primarily due to a 30% increase in heating degree days.

  These increases were partially offset by:
  · An $8 million decrease for industrial customers primarily due to lower margins.
· Margins from FERC Municipal and Cooperatives increased $10 million primarily due to higher formula rates effective June 2013.
· Margins from Off-system Sales increased $47 million primarily due to higher market prices and increased sales volumes.
· Other Revenues decreased $14 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 corresponding decrease in Other Operation and Maintenance expenses for barging as discussed below.

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

- Other Operation and Maintenance expenses decreased $1 million primarily due to the following:
  - A $13 million decrease in RTD expenses for barging activities. The decrease in RTD expenses was offset by a corresponding decrease in Other Revenues from barging activities discussed above.

  This decrease was partially offset by:
  - A $9 million increase in nuclear expenses primarily due to a prior year deferral of expenses, as regulatory assets, for future recovery as approved by the IURC effective March 2013.
  - A $2 million increase due to increased maintenance of overhead lines.
- Depreciation and Amortization expenses increased $9 million primarily due to higher depreciable base.
- Income Tax Expense increased $17 million primarily due to an increase in pretax book income.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” 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 and pension and other postretirement benefits.

See the “Accounting Pronouncements” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” beginning on page 186 for a discussion of accounting pronouncements.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013
REVENUES		
Electric Generation, Transmission and Distribution	$ 614,843	$ 490,603
Sales to AEP Affiliates	2,284	54,977
Other Revenues - Affiliated	24,727	35,825
Other Revenues - Nonaffiliated	-	1,988
TOTAL REVENUES	641,854	583,393
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	156,643	104,865
Purchased Electricity for Resale	5,362	41,812
Purchased Electricity from AEP Affiliates	72,056	101,376
Other Operation	141,350	145,238
Maintenance	48,565	45,514
Depreciation and Amortization	50,031	40,902
Taxes Other Than Income Taxes	21,823	22,456
TOTAL EXPENSES	495,830	502,163
OPERATING INCOME	146,024	81,230
Other Income (Expense):		
Interest Income	1,049	2,055
Allowance for Equity Funds Used During Construction	3,964	5,646
Interest Expense	(25,633)	(24,211)
INCOME BEFORE INCOME TAX EXPENSE	125,404	64,720
Income Tax Expense	38,315	21,263
NET INCOME	$ 87,089	$ 43,457

The common stock of I&M is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31,			
	2014		2013	
Net Income	$	87,089	$	43,457
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $229 and $1,682 in 2014 and 2013, Respectively		425		3,123
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $23 and $94 in 2014 and 2013, Respectively		43		176
TOTAL OTHER COMPREHENSIVE INCOME		468		3,299
TOTAL COMPREHENSIVE INCOME	$	87,557	$	46,756

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2012	$ 56,584	$ 980,896	$ 795,178	$ (28,883)	$ 1,803,775
Common Stock Dividends			(12,500)		(12,500)
Net Income			43,457		43,457
Other Comprehensive Income				3,299	3,299
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2013	$ 56,584	$ 980,896	$ 826,135	$ (25,584)	$ 1,838,031
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2013	$ 56,584	$ 980,896	$ 900,182	$ (15,509)	$ 1,922,153
Common Stock Dividends			(25,000)		(25,000)
Net Income			87,089		87,089
Other Comprehensive Income				468	468
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2014	$ 56,584	$ 980,896	$ 962,271	$ (15,041)	$ 1,984,710

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2014 and December 31, 2013
(in thousands)
(Unaudited)

	March 31, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2,288	$ 1,317
Advances to Affiliates	59,162	55,863
Accounts Receivable:		
Customers	52,471	63,011
Affiliated Companies	71,359	78,282
Accrued Unbilled Revenues	13,999	17,293
Miscellaneous	1,259	5,064
Allowance for Uncollectible Accounts	(33)	(184)
Total Accounts Receivable	139,055	163,466
Fuel	49,365	53,807
Materials and Supplies	206,820	209,718
Risk Management Assets	12,558	15,388
Accrued Tax Benefits	29,792	48,832
Prepayments and Other Current Assets	27,897	38,103
TOTAL CURRENT ASSETS	526,937	586,494
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	3,583,883	3,577,906
Transmission	1,310,169	1,304,225
Distribution	1,641,866	1,625,057
Other Property, Plant and Equipment (Including Plant to be Retired, Coal Mining and Nuclear Fuel)	1,440,408	1,421,361
Construction Work in Progress	476,734	427,164
Total Property, Plant and Equipment	8,453,060	8,355,713
Accumulated Depreciation, Depletion and Amortization	3,337,401	3,299,349
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,115,659	5,056,364
OTHER NONCURRENT ASSETS		
Regulatory Assets	505,750	524,114
Spent Nuclear Fuel and Decommissioning Trusts	1,962,151	1,931,610
Long-term Risk Management Assets	9,505	11,495
Deferred Charges and Other Noncurrent Assets	140,198	143,657
TOTAL OTHER NONCURRENT ASSETS	2,617,604	2,610,876
TOTAL ASSETS	$ 8,260,200	$ 8,253,734

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2014 and December 31, 2013
(dollars in thousands)
(Unaudited)

	March 31, 2014	December 31, 2013
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 121,516	$ 142,219
Affiliated Companies	69,635	93,773
Long-term Debt Due Within One Year – Nonaffiliated (March 31, 2014 and December 31, 2013 Amounts Include $99,439 and $107,143, Respectively, Related to DCC Fuel)	287,598	294,845
Risk Management Liabilities	4,134	7,029
Customer Deposits	31,851	31,103
Accrued Taxes	83,314	73,292
Accrued Interest	15,182	27,686
Obligations Under Capital Leases	48,407	46,210
Other Current Liabilities	146,801	139,088
TOTAL CURRENT LIABILITIES	808,438	855,245
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,725,246	1,744,171
Long-term Risk Management Liabilities	5,378	6,946
Deferred Income Taxes	1,184,213	1,183,350
Regulatory Liabilities and Deferred Investment Tax Credits	1,122,812	1,112,645
Asset Retirement Obligations	1,269,671	1,255,184
Deferred Credits and Other Noncurrent Liabilities	159,732	174,040
TOTAL NONCURRENT LIABILITIES	5,467,052	5,476,336
TOTAL LIABILITIES	6,275,490	6,331,581
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER’S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56,584	56,584
Paid-in Capital	980,896	980,896
Retained Earnings	962,271	900,182
Accumulated Other Comprehensive Income (Loss)	(15,041)	(15,509)
TOTAL COMMON SHAREHOLDER’S EQUITY	1,984,710	1,922,153
	$ 8,260,200	$ 8,253,734

TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014	2013
OPERATING ACTIVITIES		
Net Income	$ 87,089	$ 43,457
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	50,031	40,902
Deferred Income Taxes	21,017	26,791
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	14,821	(5,840)
Allowance for Equity Funds Used During Construction	(3,964)	(5,646)
Mark-to-Market of Risk Management Contracts	426	9,238
Amortization of Nuclear Fuel	38,049	34,000
Fuel Over/Under-Recovery, Net	11,683	417
Change in Other Noncurrent Assets	(16,211)	(9,217)
Change in Other Noncurrent Liabilities	11,505	8,577
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	24,411	22,531
Fuel, Materials and Supplies	7,340	(6,868)
Accounts Payable	(20,902)	(31,801)
Accrued Taxes, Net	29,583	14,198
Other Current Assets	5,933	8,487
Other Current Liabilities	(18,862)	(13,443)
Net Cash Flows from Operating Activities	241,949	135,783
INVESTING ACTIVITIES		
Construction Expenditures	(117,807)	(153,262)
Change in Advances to Affiliates, Net	(3,299)	(205,008)
Purchases of Investment Securities	(164,511)	(184,299)
Sales of Investment Securities	147,700	167,670
Acquisitions of Nuclear Fuel	(49,420)	(46,739)
Insurance Proceeds Related to Cook Plant Fire	-	72,000
Other Investing Activities	8,860	3,077
Net Cash Flows Used for Investing Activities	(178,477)	(346,561)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	-	247,771
Retirement of Long-term Debt – Nonaffiliated	(26,337)	(24,864)
Principal Payments for Capital Lease Obligations	(11,569)	(1,265)
Dividends Paid on Common Stock	(25,000)	(12,500)
Other Financing Activities	405	646

Net Cash Flows from (Used for) Financing Activities		(62,501)		209,788
Net Increase (Decrease) in Cash and Cash Equivalents		971		(990)
Cash and Cash Equivalents at Beginning of Period		1,317		1,562
Cash and Cash Equivalents at End of Period	$	2,288	$	572
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	34,592	$	30,116
Net Cash Paid (Received) for Income Taxes		-		(8,007)
Noncash Acquisitions Under Capital Leases		2,406		1,355
Construction Expenditures Included in Current Liabilities as of March 31,		56,668		42,430
Acquisition of Nuclear Fuel Included in Current Liabilities as of March 31,		116		1,485
Expected Reimbursement for Capital Costs of Spent Nuclear Fuel Dry Cask Storage		854		-

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to I&M's condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to I&M.

OHIO POWER COMPANY AND SUBSIDIARIES

OHIO POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Company Overview

As a public utility, OPCo engages in the transmission and distribution of power to 1,464,000 retail customers in the northwestern, central, eastern and southern sections of Ohio. OPCo purchases energy and capacity to serve its remaining generation service customers. Prior to January 1, 2014, OPCo also engaged in the generation of electric power and the subsequent sale of that power to customers. On December 31, 2013, based on FERC and PUCO orders which approved corporate separation of generation assets and associated liabilities, OPCo transferred its generation assets and related generation liabilities at net book value to AGR. In accordance with the PUCO's corporate separation order, OPCo remains responsible to provide power and capacity to OPCo customers who have not switched electric providers. Effective January 1, 2014, OPCo purchases power from both affiliated and nonaffiliated entities, subject to auction requirements and PUCO approval, to meet the energy and capacity needs of customers.

Ormet

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 operations effective immediately. The loss of Ormet's load will not have a material impact on future gross margin.

Regulatory Activity

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 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.

Litigation and Environmental Issues

In the ordinary course of business, OPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 3 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies in the 2013 Annual Report. Also, see Note 4 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 132. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 186 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2014	2013
	(in millions of KWhs)	
Retail:		
Residential	4,731	4,264
Commercial	3,579	3,386
Industrial	3,473	4,082
Miscellaneous	34	35
Total Retail (a)	11,817	11,767
Wholesale	700	3,044
Total KWhs	12,517	14,811

(a) Represents energy delivered to distribution customers.

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31, 2014	2013
	(in degree days)	
Actual - Heating (a)	2,409	1,971
Normal - Heating (b)	1,880	1,885
Actual - Cooling (c)	-	-
Normal - Cooling (b)	3	3

(a) Eastern 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 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
(in millions)

First Quarter of 2013	$	130
Changes in Gross Margin:		
Retail Margins		(219)
Off-system Sales		(27)
Transmission Revenues		15
Other Revenues		(14)
Total Change in Gross Margin		(245)
Changes in Expenses and Other:		
Other Operation and Maintenance		72
Depreciation and Amortization		33
Taxes Other Than Income Taxes		10
Interest and Investment Income		4
Carrying Costs Income		4
Interest Expense		17
Total Change in Expenses and Other		140
Income Tax Expense		36
First Quarter of 2014	$	61

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

- Retail Margins decreased $219 million primarily due to the following:
  - A $106 million decrease attributable to purchased power due to the AGR Power Supply Agreement related to the base generation SSO load.
  - An $87 million decrease due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013.
  - A $14 million decrease attributable to customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.

  These decreases were partially offset by:
  - 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.
- Margins from Off-system Sales decreased $27 million due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013.
-

Transmission Revenues increased $15 million primarily due to increased transmission revenues from customers who have switched to alternative CRES providers and rate increases for customers in the PJM region. The increase in transmission revenues related to CRES providers offsets lost revenues included in Retail Margins above.

- Other Revenues decreased $14 million due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013. This decrease in Other Revenues has a corresponding decrease in Other Operation and Maintenance expense below.

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

- Other Operation and Maintenance expenses decreased $72 million primarily due to the following:
  - A $114 million decrease due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013.

  This decrease was partially offset by:
  - A $15 million increase in PJM expenses.
  - 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 was offset by a corresponding increase in Retail Margins above.
  - A $4 million increase in employee-related expenses.
  - A $4 million increase in storm expense.
  - A $3 million increase in expense related to the factoring of receivables.
- Depreciation and Amortization expenses decreased $33 million primarily due to the following:
  - A $49 million decrease due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013.

  This decrease was partially offset by:
  - A $5 million increase in amortization of securitized regulatory assets and recognition of previously unrecognized equity being recovered through the Deferred Asset Phase-In Rider. This increase was offset by a corresponding increase in Retail Margins above.
  - A $4 million increase 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 decreased $10 million due to the following:
  - An $18 million decrease due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013.

  This decrease was partially offset by:
  - A $6 million increase in property taxes due to increased investment in transmission and distribution assets and increased tax rates.
  - A $2 million increase in state excise taxes due to increased metered KWh sales.
- Interest and Investment Income increased $4 million primarily due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013.
- Carrying Costs Income increased $4 million primarily due to increased capacity deferral carrying charges.
- Interest Expense decreased $17 million primarily due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013.
- Income Tax Expense decreased $36 million primarily due to a decrease in pretax book income.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" 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 and pension and other postretirement benefits.

See the "Accounting Pronouncements" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 186 for a discussion of accounting pronouncements.

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OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014	2013
REVENUES		
Electric Generation, Transmission and Distribution	$ 846,906	$ 933,681
Sales to AEP Affiliates	31,978	285,642
Other Revenues – Affiliated	-	7,840
Other Revenues – Nonaffiliated	1,308	6,627
TOTAL REVENUES	880,192	1,233,790
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	-	409,584
Purchased Electricity for Resale	79,130	43,185
Purchased Electricity from AEP Affiliates	314,124	80,381
Amortization of Generation Deferrals	31,186	-
Other Operation	151,426	184,187
Maintenance	34,651	74,295
Depreciation and Amortization	58,699	92,324
Taxes Other Than Income Taxes	95,257	105,021
TOTAL EXPENSES	764,473	988,977
OPERATING INCOME	115,719	244,813
Other Income (Expense):		
Interest Income	3,274	363
Carrying Costs Income	7,114	3,263
Allowance for Equity Funds Used During Construction	1,726	1,304
Interest Expense	(33,007)	(50,173)
INCOME BEFORE INCOME TAX EXPENSE	94,826	199,570
Income Tax Expense	34,052	69,796
NET INCOME	$ 60,774	$ 129,774

The common stock of OPCo is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014		Three Months Ended March 31, 2013	
Net Income	$	60,774	$	129,774
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $241 and $574 in 2014 and 2013, Respectively		(448)		1,066
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1,760 in 2013		-		3,269
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)		(448)		4,335
TOTAL COMPREHENSIVE INCOME	$	60,326	$	134,109

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2012	$ 321,201	$ 1,744,099	$ 2,626,134	$ (165,725)	$ 4,525,709
Common Stock Dividends			(75,000)		(75,000)
Net Income			129,774		129,774
Other Comprehensive Income				4,335	4,335
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2013	$ 321,201	$ 1,744,099	$ 2,680,908	$ (161,390)	$ 4,584,818
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2013	$ 321,201	$ 663,782	$ 633,203	$ 7,079	$ 1,625,265
Common Stock Dividends			(25,000)		(25,000)
Net Income			60,774		60,774
Other Comprehensive Loss				(448)	(448)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2014	$ 321,201	$ 663,782	$ 668,977	$ 6,631	$ 1,660,591

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2014 and December 31, 2013
(in thousands)
(Unaudited)

	March 31, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$ 4,780	$ 3,004
Restricted Cash for Securitized Funding	32,054	19,387
Advances to Affiliates	-	339,070
Accounts Receivable:		
Customers	96,218	67,054
Affiliated Companies	72,311	74,771
Accrued Unbilled Revenues	49,761	36,353
Miscellaneous	747	1,559
Allowance for Uncollectible Accounts	(39,602)	(34,984)
Total Accounts Receivable	179,435	144,753
Notes Receivable Due Within One Year – Affiliated	178,580	178,580
Materials and Supplies	55,311	53,711
Risk Management Assets	3,980	3,082
Deferred Income Tax Benefits	33,642	36,105
Accrued Tax Benefits	487	7,109
Regulatory Asset for Under-Recovered Fuel Costs	26,153	15,829
Prepayments and Other Current Assets	7,085	6,483
TOTAL CURRENT ASSETS	521,507	807,113
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	2,030,881	2,011,289
Distribution	3,907,852	3,877,532
Other Property, Plant and Equipment	379,780	364,573
Construction Work in Progress	188,636	185,428
Total Property, Plant and Equipment	6,507,149	6,438,822
Accumulated Depreciation and Amortization	1,986,318	1,973,042
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,520,831	4,465,780
OTHER NONCURRENT ASSETS		
Notes Receivable – Affiliated	118,245	118,245
Regulatory Assets	1,398,055	1,378,697
Securitized Assets	126,597	131,582
Deferred Charges and Other Noncurrent Assets	211,819	260,141
TOTAL OTHER NONCURRENT ASSETS	1,854,716	1,888,665
TOTAL ASSETS	$ 6,897,054	$ 7,161,558

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2014 and December 31, 2013
(Unaudited)

	March 31, 2014	December 31, 2013
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 27,108	$ -
Accounts Payable:		
General	128,333	146,307
Affiliated Companies	195,954	222,889
Long-term Debt Due Within One Year – Nonaffiliated (March 31, 2014 and December 31, 2013 Amounts Include $57,137 and $34,936, Respectively, Related to Ohio Phase-in-Recovery Funding)	235,785	438,595
Accrued Taxes	324,491	429,260
Accrued Interest	49,854	40,853
Other Current Liabilities	128,143	144,334
TOTAL CURRENT LIABILITIES	1,089,668	1,422,238
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (March 31, 2014 and December 31, 2013 Amounts Include $210,266 and $232,466, Respectively, Related to Ohio Phase-in-Recovery Funding)	2,274,500	2,296,580
Deferred Income Taxes	1,352,301	1,330,711
Regulatory Liabilities and Deferred Investment Tax Credits	467,433	435,499
Employee Benefits and Pension Obligations	28,789	28,329
Deferred Credits and Other Noncurrent Liabilities	23,772	22,936
TOTAL NONCURRENT LIABILITIES	4,146,795	4,114,055
TOTAL LIABILITIES	5,236,463	5,536,293
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER’S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321,201	321,201
Paid-in Capital	663,782	663,782
Retained Earnings	668,977	633,203
Accumulated Other Comprehensive Income (Loss)	6,631	7,079
TOTAL COMMON SHAREHOLDER’S EQUITY	1,660,591	1,625,265

TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$	6,897,054	$	7,161,558

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013
OPERATING ACTIVITIES		
Net Income	$ 60,774	$ 129,774
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for)		
Operating Activities:		
Depreciation and Amortization	58,699	92,324
Amortization of Generation Deferrals	31,186	-
Deferred Income Taxes	24,917	55,328
Carrying Costs Income	(7,114)	(3,263)
Allowance for Equity Funds Used During Construction	(1,726)	(1,304)
Mark-to-Market of Risk Management Contracts	(1,060)	12,901
Property Taxes	48,743	55,246
Fuel Over/Under-Recovery, Net	12,265	9,191
Deferral of Ohio Capacity Costs, Net	(56,167)	(49,056)
Change in Other Noncurrent Assets	(21,285)	14,092
Change in Other Noncurrent Liabilities	29,277	1,730
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(34,984)	58,235
Fuel, Materials and Supplies	(1,600)	(1,388)
Accounts Payable	(30,911)	(42,749)
Accrued Taxes, Net	(98,147)	(91,308)
Other Current Assets	(1,415)	(705)
Other Current Liabilities	(13,633)	(21,374)
Net Cash Flows from (Used for) Operating Activities	(2,181)	217,674
INVESTING ACTIVITIES		
Construction Expenditures	(100,220)	(131,590)
Change in Restricted Cash for Securitized Funding	(12,668)	-
Change in Advances to Affiliates, Net	339,070	106,080
Other Investing Activities	1,162	9,760
Net Cash Flows from (Used for) Investing Activities	227,344	(15,750)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Affiliated	-	200,000
Change in Advances from Affiliates, Net	27,108	172,211
Retirement of Long-term Debt – Nonaffiliated	(225,029)	(500,000)
Principal Payments for Capital Lease Obligations	(1,396)	(2,508)
Dividends Paid on Common Stock	(25,000)	(75,000)
Other Financing Activities	930	760

Net Cash Flows Used for Financing Activities		(223,387)		(204,537)
Net Increase (Decrease) in Cash and Cash Equivalents		1,776		(2,613)
Cash and Cash Equivalents at Beginning of Period		3,004		3,640
Cash and Cash Equivalents at End of Period	$	4,780	$	1,027
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	23,425	$	50,327
Net Cash Paid (Received) for Income Taxes		-		(2,390)
Noncash Acquisitions Under Capital Leases		3,324		1,811
Government Grants Included in Accounts Receivable as of March 31,		-		1,147
Construction Expenditures Included in Current Liabilities as of March 31,		46,910		69,152

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

OHIO POWER COMPANY AND SUBSIDIARIES
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF
REGISTRANT SUBSIDIARIES

The condensed notes to OPCo’s condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to OPCo.

PUBLIC SERVICE COMPANY OF OKLAHOMA

PUBLIC SERVICE COMPANY OF OKLAHOMA
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Regulatory Activity

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.

Litigation and Environmental Issues

In the ordinary course of business, PSO is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 3 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies in the 2013 Annual Report. Also, see Note 4 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 132. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 186 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

		Three Months Ended March 31,	
		2014	2013
		(in millions of KWhs)	
Retail:			
	Residential	1,634	1,436
	Commercial	1,139	1,079
	Industrial	1,193	1,194
	Miscellaneous	278	277
Total Retail		4,244	3,986

Wholesale	227	255
Total KWhs	4,471	4,241

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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.

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31, 2014	2013
	(in degree days)	
Actual - Heating (a)	1,369	1,089
Normal - Heating (b)	1,045	1,045
Actual - Cooling (c)	3	5
Normal - Cooling (b)	15	15

(a) 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) 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
(in millions)

First Quarter of 2013	$	14
Changes in Gross Margin:		
Transmission Revenues		1
Total Change in Gross Margin		1
Changes in Expenses and Other:		
Other Operation and Maintenance		(7)
Taxes Other Than Income Taxes		(2)
Other Income		(1)
Total Change in Expenses and Other		(10)
Income Tax Expense		3
First Quarter of 2014	$	8

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

- Other Operation and Maintenance expenses increased $7 million primarily due to the following:
  - A $6 million increase in transmission expenses primarily due to increased SPP transmission services.
  - A $2 million increase in generation plant operation and maintenance expenses.

  These increases were partially offset by:
  - A $3 million decrease in distribution expenses primarily related to the amortization of the 2007 and 2010 storm deferrals which were fully recovered in 2013.
- Income Tax Expense decreased $3 million primarily due to a decrease in pretax book income.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” 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 and pension and other postretirement benefits.

See the “Accounting Pronouncements” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” beginning on page 186 for a discussion of accounting pronouncements.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014	2013
REVENUES		
Electric Generation, Transmission and Distribution	$ 296,710	$ 259,903
Sales to AEP Affiliates	4,597	1,834
Other Revenues	78	552
TOTAL REVENUES	301,385	262,289
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	65,937	43,310
Purchased Electricity for Resale	79,691	64,655
Purchased Electricity from AEP Affiliates	11,024	10,216
Other Operation	58,711	47,807
Maintenance	24,745	28,572
Depreciation and Amortization	23,982	24,180
Taxes Other Than Income Taxes	11,969	9,997
TOTAL EXPENSES	276,059	228,737
OPERATING INCOME	25,326	33,552
Other Income (Expense):		
Other Income	1,428	2,115
Interest Expense	(13,317)	(13,340)
INCOME BEFORE INCOME TAX EXPENSE	13,437	22,327
Income Tax Expense	4,989	8,634
NET INCOME	$ 8,448	$ 13,693

The common stock of PSO is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013
Net Income	$ 8,448	$ 13,693
OTHER COMPREHENSIVE LOSS, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $132 and $90 in 2014 and 2013, Respectively	(246)	(167)
TOTAL COMPREHENSIVE INCOME	$ 8,202	$ 13,526

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2012	$ 157,230	$ 364,037	$ 388,530	$ 6,481	$ 916,278
Common Stock Dividends			(13,750)		(13,750)
Net Income			13,693		13,693
Other Comprehensive Loss				(167)	(167)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2013	$ 157,230	$ 364,037	$ 388,473	$ 6,314	$ 916,054
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2013	$ 157,230	$ 364,037	$ 415,076	$ 5,758	$ 942,101
Net Income			8,448		8,448
Other Comprehensive Loss				(246)	(246)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2014	$ 157,230	$ 364,037	$ 423,524	$ 5,512	$ 950,303

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2014 and December 31, 2013
(in thousands)
(Unaudited)

	March 31, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,756	$ 1,277
Accounts Receivable:		
Customers	29,384	32,314
Affiliated Companies	18,634	30,392
Miscellaneous	3,460	3,102
Allowance for Uncollectible Accounts	(325)	(462)
Total Accounts Receivable	51,153	65,346
Fuel	15,054	15,191
Materials and Supplies	52,695	52,707
Risk Management Assets	1,349	1,167
Deferred Income Tax Benefits	-	7,333
Accrued Tax Benefits	35,708	21,665
Regulatory Asset for Under-Recovered Fuel Costs	26,692	3,298
Prepayments and Other Current Assets	5,994	6,194
TOTAL CURRENT ASSETS	190,401	174,178
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,236,105	1,203,221
Transmission	727,512	731,312
Distribution	2,001,049	1,986,032
Other Property, Plant and Equipment (Including Plant to be Retired)	411,700	393,026
Construction Work in Progress	172,949	175,890
Total Property, Plant and Equipment	4,549,315	4,489,481
Accumulated Depreciation and Amortization	1,334,507	1,323,522
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	3,214,808	3,165,959
OTHER NONCURRENT ASSETS		
Regulatory Assets	164,929	156,690
Employee Benefits and Pension Assets	23,162	22,629
Deferred Charges and Other Noncurrent Assets	38,197	7,238
TOTAL OTHER NONCURRENT ASSETS	226,288	186,557
TOTAL ASSETS	$ 3,631,497	$ 3,526,694

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

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PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2014 and December 31, 2013
(Unaudited)

		March 31, 2014		December 31, 2013
		(in thousands)		
CURRENT LIABILITIES				
Advances from Affiliates	$	70,119	$	36,772
Accounts Payable:				
General		106,312		150,184
Affiliated Companies		45,468		45,427
Long-term Debt Due Within One Year – Nonaffiliated		34,118		34,115
Risk Management Liabilities		83		85
Customer Deposits		45,676		45,379
Accrued Taxes		44,847		23,442
Accrued Interest		15,040		12,646
Other Current Liabilities		80,931		58,992
TOTAL CURRENT LIABILITIES		442,594		407,042
NONCURRENT LIABILITIES				
Long-term Debt – Nonaffiliated		1,015,675		965,695
Deferred Income Taxes		848,101		836,556
Regulatory Liabilities and Deferred Investment Tax Credits		328,224		327,673
Employee Benefits and Pension Obligations		9,966		10,561
Deferred Credits and Other Noncurrent Liabilities		36,634		37,066
TOTAL NONCURRENT LIABILITIES		2,238,600		2,177,551
TOTAL LIABILITIES		2,681,194		2,584,593
Rate Matters (Note 4)				
Commitments and Contingencies (Note 5)				
COMMON SHAREHOLDER’S EQUITY				
Common Stock – Par Value – $15 Per Share:				
Authorized – 11,000,000 Shares				
Issued – 10,482,000 Shares				
Outstanding – 9,013,000 Shares		157,230		157,230
Paid-in Capital		364,037		364,037
Retained Earnings		423,524		415,076
Accumulated Other Comprehensive Income (Loss)		5,512		5,758
TOTAL COMMON SHAREHOLDER’S EQUITY		950,303		942,101
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$	3,631,497	$	3,526,694

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014	2013
OPERATING ACTIVITIES		
Net Income	$ 8,448	$ 13,693
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	23,982	24,180
Deferred Income Taxes	19,178	20,242
Allowance for Equity Funds Used During Construction	(1,431)	(980)
Mark-to-Market of Risk Management Contracts	(267)	(3,013)
Property Taxes	(31,260)	(28,730)
Fuel Over/Under-Recovery, Net	(23,394)	(17,812)
Change in Regulatory Assets	(8,468)	4,165
Change in Other Noncurrent Assets	(1,045)	(3,780)
Change in Other Noncurrent Liabilities	(2,204)	4,620
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	14,193	1,665
Fuel, Materials and Supplies	149	1,344
Accounts Payable	(16,891)	(5,827)
Accrued Taxes, Net	7,362	6,106
Other Current Assets	(395)	1,181
Other Current Liabilities	22,401	10,663
Net Cash Flows from Operating Activities	10,358	27,717
INVESTING ACTIVITIES		
Construction Expenditures	(93,500)	(54,298)
Change in Advances to Affiliates, Net	-	10,558
Other Investing Activities	776	5,196
Net Cash Flows Used for Investing Activities	(92,724)	(38,544)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	49,975	-
Change in Advances from Affiliates, Net	33,347	24,004
Retirement of Long-term Debt – Nonaffiliated	(102)	(99)
Principal Payments for Capital Lease Obligations	(941)	(754)
Dividends Paid on Common Stock	-	(13,750)
Other Financing Activities	566	533
Net Cash Flows from Financing Activities	82,845	9,934
Net Increase (Decrease) in Cash and Cash Equivalents	479	(893)
Cash and Cash Equivalents at Beginning of Period	1,277	1,367

Cash and Cash Equivalents at End of Period	$	1,756	$	474
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	10,487	$	10,519
Net Cash Paid for Income Taxes		67		284
Noncash Acquisitions Under Capital Leases		904		1,015
Construction Expenditures Included in Current Liabilities as of March 31,		34,199		19,868

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF
REGISTRANT SUBSIDIARIES

The condensed notes to PSO's condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to PSO.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Regulatory Activity

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.

2014 Louisiana Formula Rate Filing

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

Welsh Plant, Units 1 and 3 - Environmental Projects

To comply with pending Federal EPA regulations, SWEPCo is currently constructing environmental control projects to meet Mercury and Air Toxics Standards for Welsh Plant, Units 1 and 3 at a cost of approximately $410 million, excluding AFUDC. Management currently estimates that the total environmental projects to be completed through 2020 for Welsh Plant, Units 1 and 3 will cost approximately $600 million, excluding AFUDC. As of 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.

Litigation and Environmental Issues

In the ordinary course of business, SWEPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 3 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies in the 2013 Annual Report. Also, see Note 4 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 132. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the “Executive Overview” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” section beginning on page 186 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

		Three Months Ended March 31, 2014	2013
		(in millions of KWhs)	
Retail:			
	Residential	1,747	1,494
	Commercial	1,393	1,279
	Industrial	1,377	1,259
	Miscellaneous	20	19
Total Retail		4,537	4,051
Wholesale		2,279	2,443
Total KWhs		6,816	6,494

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.

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31, 2014	2013
	(in degree days)	
Actual - Heating (a)	994	732
Normal - Heating (b)	721	728
Actual - Cooling (c)	10	16
Normal - Cooling (b)	33	33

(a) 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) 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
(in millions)

First Quarter of 2013	$	12
Changes in Gross Margin:		
Retail Margins (a)		24
Off-system Sales		2
Transmission Revenues		2
Total Change in Gross Margin		28
Changes in Expenses and Other:		
Other Operation and Maintenance		(12)
Depreciation and Amortization		(1)
Taxes Other Than Income Taxes		(1)
Other Income		1
Interest Expense		2
Total Change in Expenses and Other		(11)
Income Tax Expense		(6)
First Quarter of 2014	$	23

(a) Includes firm wholesale sales to municipals and cooperatives.

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 $24 million primarily due to the following:
  - A $24 million increase primarily due to the Louisiana and Texas rate orders related to the Turk Plant.
  - A $6 million increase in weather-related usage primarily due to a 36% increase in heating degree days.

  These increases were partially offset by:
  - A $4 million decrease primarily due to 2013 fuel recovery adjustments.

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

- Other Operation and Maintenance expenses increased $12 million primarily due to the following:
  - A $6 million increase in transmission expenses primarily due to increased SPP transmission services.
  - A $4 million increase in generation plant operation and maintenance expenses.
- Income Tax Expense increased $6 million primarily due to an increase in pretax book income.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” 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 and pension and other postretirement benefits.

See the “Accounting Pronouncements” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” beginning on page 186 for a discussion of accounting pronouncements.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014	2013
REVENUES		
Electric Generation, Transmission and Distribution	$ 426,627	$ 381,277
Sales to AEP Affiliates	13,598	12,709
Other Revenues	365	331
TOTAL REVENUES	440,590	394,317
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	145,587	151,358
Purchased Electricity for Resale	61,165	39,760
Purchased Electricity from AEP Affiliates	3,766	1,017
Other Operation	68,537	59,448
Maintenance	30,411	27,791
Depreciation and Amortization	45,661	44,882
Taxes Other Than Income Taxes	20,737	19,422
TOTAL EXPENSES	375,864	343,678
OPERATING INCOME	64,726	50,639
Other Income (Expense):		
Other Income	1,967	1,054
Interest Expense	(31,876)	(33,990)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	34,817	17,703
Income Tax Expense	12,165	6,796
Equity Earnings of Unconsolidated Subsidiary	310	641
NET INCOME	22,962	11,548
Net Income Attributable to Noncontrolling Interest	1,102	1,090
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 21,860	$ 10,458

The common stock of SWEPCo is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014		2013	
Net Income	$	22,962	$	11,548
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $270 and $321 in 2014 and 2013, Respectively		502		596
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $126 and $34 in 2014 and 2013, Respectively		(234)		(63)
TOTAL OTHER COMPREHENSIVE INCOME		268		533
TOTAL COMPREHENSIVE INCOME		23,230		12,081
Total Comprehensive Income Attributable to Noncontrolling Interest		1,102		1,090
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$	22,128	$	10,991

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 132.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2012	$ 135,660	$ 674,606	$ 1,228,806	$ (17,860)	$ 261	$ 2,021,473