AMERICAN ELECTRIC POWER CO INC
Form 10-Q
July 23, 2015

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 June 30, 2015
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.

Large accelerated filer X 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 July 23, 2015
American Electric Power Company, Inc.	490,559,618 ($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
June 30, 2015

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 Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a subsidiary of AEP Transmission Holdco and an intermediate holding company that owns seven wholly-owned transmission companies.
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.
APSC	Arkansas Public Service Commission.
ASU	Accounting Standards Update.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO_2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CRES provider	Competitive Retail Electric Service providers under Ohio law that target retail customers by offering alternative generation service.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel IV LLC, DCC Fuel VI LLC, DCC Fuel VII and DCC Fuel VIII 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.
Energy Supply	AEP Energy Supply LLC, a nonregulated holding company for AEP's competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.

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Term	Meaning
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IEU	Industrial Energy Users-Ohio.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo, which defined the sharing of costs and benefits associated with their respective generation plants. This agreement was terminated January 1, 2014.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
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.
NO_x	Nitrogen oxide.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NSR	New Source Review.
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.

PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, I&M, OPCo, PSO and SWEPCo.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.

Term	Meaning
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RPM	Reliability Pricing Model.
RSR	Retail Stability Rider.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity for AEP and SWEPCo.
SEC	U.S. Securities and Exchange Commission.
SEET	Significantly Excessive Earnings Test.
SIA	System Integration Agreement, effective June 15, 2000, as amended, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant, a 534 MW natural gas unit owned by SWEPCo.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Transition Funding	AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation.
Transource Energy	Transource Energy, LLC, a consolidated variable interest entity formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Transource Missouri	A 100% wholly-owned subsidiary of Transource Energy.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
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 2014 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 ref future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, we undertake no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

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

Our ability to recover through rates or market prices any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.

Volatility and changes in markets for capacity and electricity, coal and other energy-related commodities, particularly changes in the price of natural gas and capacity auction returns.

Changes in utility regulation and the allocation of costs within regional transmission organizations, including ERCOT, PJM and SPP.

The transition to market for generation in Ohio, including the implementation of ESPs and our ability to recover investments in our Ohio generation assets.

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

The forward looking statements of AEP and its Registrant Subsidiaries speak only as of the date of this report or as of the date they are made. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information. For a more detailed discussion of these factors, see "Risk Factors" in Part I of the 2014 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

Customer Demand

Our weather-normalized retail sales volumes for the second quarter of 2015 increased by 0.9% from the second quarter of 2014. Our second quarter 2015 industrial sales increased 0.6% compared to the second quarter of 2014 primarily due to increased sales to customers in oil and gas related sectors. Weather-normalized commercial and residential sales increased 1.9% and 0.3% in the second quarter of 2015, respectively, from the second quarter of 2014.
Our weather-normalized retail sales volumes for the six months ended June 30, 2015 decreased 0.3% compared to the six months ended June 30, 2014. Industrial sales volumes increased 0.9% compared to 2014, while weather-normalized commercial sales increased by 0.7%. Weather-normalized residential sales decreased 2.2% in comparison to the first six months of 2014.

Merchant Fleet Alternatives

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

AEP River Operations Alternatives

AEP is evaluating strategic alternatives for its non-regulated AEP River Operations segment, which primarily includes commercial barging operations that transport liquids, coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi rivers. Potential alternatives may include, but are not limited to, continued ownership or a sale of the non-regulated river operations. We have not made a decision regarding the potential alternatives, nor have we set a specific time frame for a decision. We do not expect to incur a loss related to a potential sale transaction.

Merchant Portion of Turk Plant

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

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

SWEPCo’s wholesale customers under FERC-based rates.

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

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Ohio Electric Security Plan Filings

2009 - 2011 ESP

In August 2012, the PUCO issued an order in a separate proceeding which implemented a PIRR to recover OPCo's deferred fuel costs in rates beginning September 2012. In June 2015, the Supreme Court of Ohio issued a decision that reversed, as requested by OPCo, the PUCO order on the carrying cost rate issue and dismissed the appeal filed by the IEU. In June 2015, the IEU filed a motion for reconsideration with the Supreme Court of Ohio related to the accumulated deferred income tax credit. If the Supreme Court of Ohio upholds its June 2015 order, it would remand the matter back to the PUCO for reinstatement of the weighted average cost of capital rate.

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 established base generation rates through May 2015. This ruling was generally upheld in PUCO rehearing orders in January and March 2013.

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

As part of the August 2012 ESP order, the PUCO established a non-bypassable RSR, effective September 2012. The RSR was collected from customers at $3.50/MWh through May 2014 and 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. In July 2014, OPCo submitted a separate application to continue the RSR to collect the unrecovered portion of the deferred capacity costs at the rate of $4.00/MWh, until the balance of the capacity deferrals has been collected. In April 2015, the PUCO issued an order approving the application to continue the RSR, with modifications. In May 2015, the PUCO granted intervenors requests for rehearing. As of June 30, 2015, OPCo's incurred deferred capacity costs balance was $432 million, including debt carrying costs.

In November 2013, the PUCO issued an order approving OPCo's competitive bid process with modifications. As ordered, in 2014, OPCo conducted multiple energy-only auctions for a total of 100% of the SSO load with delivery beginning April 2014 through May 2015. As provided for in the June 2015 - May 2018 ESP, for delivery starting in June 2015, OPCo now conducts energy and capacity auctions for its entire SSO load. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings.

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

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

June 2015 - May 2018 ESP

In December 2013, OPCo filed an application with the PUCO to approve an ESP that included proposed rate adjustments and the continuation and modification of certain existing riders effective June 2015 through May 2018. The proposal included a return on common equity of 10.65% on capital costs for certain riders. The proposal also included a purchased power agreement (PPA) rider that would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based PPA. In October 2014, OPCo filed a separate application with the PUCO to propose a new extended PPA with AGR for 2,671 MW for inclusion in the PPA rider.

In February 2015, the PUCO issued an order approving OPCo's ESP application, subject to certain modifications, with a return on common equity of 10.2% on capital costs for certain riders. The order included (a) approval of the Distribution Investment Rider (DIR) with modified rate caps established by the PUCO, (b) authorization to establish a zero rate rider for OPCo's proposed PPA, (c) the option for OPCo to reapply in a future proceeding with a more detailed PPA proposal and (d) a directive to continue to pursue the transfer of the OVEC contractual entitlement to AGR or to otherwise divest of its interest in OVEC. In May 2015, on rehearing, the PUCO issued an order that increased the DIR rate caps and deferred ruling on all requests for rehearing related to the establishment of the PPA rider. In June 2015, OPCo and various intervenors filed applications for rehearing with the PUCO related to the May 2015 order on rehearing. In July 2015, the PUCO granted the requests for rehearing.

In May 2015, OPCo filed an amended PPA application between OPCo and AGR that (a) included OPCo's OVEC contractual entitlement, (b) addressed the PPA requirements set forth in the PUCO's February 2015 order, (c) updated supporting testimony to reflect a current analysis of the PPA proposal and (d) continued to include the 2,671 MW to be available for capacity, energy and ancillary services, produced by AGR over the lives of the respective generating units.

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

2012 Texas Base Rate Case

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

2012 Louisiana Formula Rate Filing

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

2015 Oklahoma Base Rate Case

In July 2015, PSO filed a request with the OCC to increase annual revenues by $137 million to recover costs associated with its environmental compliance plan and to recover investments and other costs that have increased since the last base rate case. The annual increase consists of (a) a base rate increase of $89 million, which includes $48 million in increased depreciation expense that reflects, among other things, recovery through June 2026 for Northeastern Plant, Units 3 and 4, (b) a rider or base rate increase of $44 million to recover costs for the environmental controls being installed on Northeastern Plant, Unit 3 and the Comanche Plant and (c) a request to include environmental consumable costs in the FAC, estimated to be $4 million annually. The rate increase includes a proposed return on equity of 10.5% and is proposed to be effective in January 2016, except for the $44 million for environmental investments, which is proposed to be effective in March 2016, after the Northeastern Plant, Unit 3 environmental controls go in service. In addition, the filing also notified the OCC that future incremental purchased capacity and energy costs of an estimated $35 million will be incurred related to the environmental compliance plan, due to the closure of Northeastern Plant, Unit 4 in April 2016, which would be recovered through the FAC. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the “2015 Oklahoma Base Rate Case" section of Note 4.

2014 West Virginia Base Rate Case

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

In May 2015, the WVPSC issued an order on the base rate case. Upon implementation of the order in May 2015, and consistent with the WVPSC authorized total revenue, annual base rates were authorized to be increased by $99 million. The order included a delayed billing of $25 million of the annual base rate increase to residential customers until July 2016. The order provided for carrying charges based upon a weighted average cost of capital rate for the $25 million annual delayed billing through June 2016, and stated recovery would be addressed in the next ENEC case scheduled for 2016. Additionally, the order included approval of (a) an initial vegetation management rider of $45 million annually, (b) revised deprecation rates, including recovery of plants to be retired and (c) the recovery of $89 million in previously recorded regulatory assets, which will predominantly be recovered over five years. See the “2014 West Virginia Base Rate Case” section of Note 4.

New Virginia Legislation Affecting Biennial Reviews

In February 2015, amendments to Virginia law governing the regulation of investor-owned electric utilities were enacted. Under the amended Virginia law, APCo’s existing generation and distribution base rates are frozen until after the Virginia SCC rules on APCo’s next biennial review, which APCo will file in March 2020 for the 2018 and 2019 test years. These amendments also preclude the Virginia SCC from performing biennial reviews of APCo’s earnings for the years 2014 through 2017. APCo's financial statements adequately address the impact of these amendments. The new law provides that APCo will absorb its Virginia jurisdictional share of incremental generation and distribution costs incurred during 2014 through 2017 that are associated with severe weather events and/or natural disasters and costs associated with potential impairments related to new carbon emission guidelines issued by the Federal EPA.

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Kentucky Fuel Adjustment Clause Review

In August 2014, the KPSC issued an order initiating a review of KPCo's FAC from November 2013 through April 2014. In January 2015, the KPSC issued an order disallowing certain FAC costs during the period of January 2014 through May 2015 while KPCo owned and operated both Big Sandy Plant, Unit 2 and its one-half interest in the Mitchell Plant. As a result of this order, KPCo recorded a regulatory disallowance of $36 million in December 2014. In February 2015, KPCo filed an appeal of this order with the Franklin County Circuit Court. In April 2015, the Franklin County Circuit Court issued an order approving intervenors' requests to hold this case in abeyance until the KPSC issues a final order in KPCo’s two-year FAC review case for the period November 2012 through October 2014. See the “Kentucky Fuel Adjustment Clause Review” section of Note 4.

2014 Kentucky Base Rate Case

In December 2014, KPCo filed a request with the KPSC for a net increase in rates of $70 million, which consists of a $75 million increase in rider rates, offset by a $5 million decrease in annual base rates, to be effective July 2015. In April 2015, a non-unanimous stipulation agreement between KPCo and certain intervenors was filed with the KPSC. The parties to the stipulation recommended a net revenue increase of $45 million, which consisted of a $68 million increase in rider rates, offset by a $23 million decrease in annual base rates, to be effective July 2015. Additionally, the agreement included (a) recovery of $12 million of deferred storm costs, (b) any difference between the actual off-system sales margins and the $15 million included in the proposed annual base rates to be shared with 75% to the customer and 25% to KPCo and (c) dismissal of the KPCo and the Kentucky Industrial Utility Customers appeals of the KPSC order in the KPCo fuel adjustment clause review for November 2012 through October 2014.

In June 2015, the KPSC issued an order that approved a modified stipulation agreement. The order approved a net revenue increase of $45 million and contained modifications that included (a) approval to recover $2 million of IGCC and certain carbon capture study costs, both over 25 years, (b) no deferral of certain PJM costs and (c) denial of the recovery of certain potential purchased power costs through a rider. Once this order becomes final and non-appealable, KPCo will withdraw its appeal of the KPSC order in the KPCo fuel adjustment clause review. See "Kentucky Fuel Adjustment Clause Review" section above. See the “2014 Kentucky Base Rate Case” section of Note 4.

PJM Capacity Market

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

Through May 2015, AGR provided generation capacity to OPCo for both switched and non-switched OPCo generation customers. For switched customers, OPCo paid AGR $188.88/MW day for capacity. For non-switched OPCo generation customers, OPCo paid AGR its blended tariff rate for capacity consisting of $188.88/MW day for auctioned load and the non-fuel generation portion of its base rate for non-auctioned load. AGR’s excess capacity was subject to the PJM RPM auction. After May 2015, AGR's generation assets are subject to PJM capacity prices. Shown below are the base RPM results through the June 2017 through May 2018 period:

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

Management expects a significant decline in AGR capacity revenues after May 2015 because the Power Supply Agreement between AGR and OPCo ended. Management also expects a further decline in AGR capacity revenues from June 2016 through May 2017 based upon the RPM results.

FERC has previously accepted incremental improvements relating to the PJM RPM auction including: (a) assuring that capacity imports have firm transmission, (b) placing limits on the number of MWs of summer-only demand response, (c) modification and enforcement of the dispatch of demand response to better reflect real-time capacity requirements, and (d) redesigning the RPM demand curve. Collectively, these improvements should reduce capacity price volatility and improve reliability.

In December 2014, PJM filed with FERC for approval of a new type of capacity product, the Capacity Performance Product (CP), intended to improve generator performance and reliability during emergency events by: (a) assessing higher penalties for non-performance during emergency events, (b) allowing higher offers into the auction and (c) requiring generators to provide assurances that they can perform reliably during emergency events.

In June 2015, FERC issued an order accepting most of PJM’s recommendations, including: (a) non-performance assessments based on the calculated cost of new entry, (b) capacity offers up to approximately $250/MW day for the June 2018 through May 2019 period without mitigation, (c) significant authority to review capacity offers for compliance with CP criteria, and (d) supplemental CP auctions for the June 2016 through May 2017, and June 2017 through May 2018 periods. These supplemental auctions address capacity performance and reliability issues in these interim years, and allow generators to re-offer at a higher price for capacity already cleared if they can perform as a CP resource. In July 2015, FERC issued a revision to its order, allowing demand response providers to participate in the supplemental auctions. The supplemental auctions for the June 2016 through May 2017 and June 2017 through May 2018 periods will take place during the third quarter of 2015.

FERC rejected AEP’s request for a full exemption from the CP rules for Fixed Resource Requirement entities, but did allow an exemption for the June 2018 through May 2019 period. FERC also rejected PJM’s recommendation for a monthly stop-loss provision. AEP filed a rehearing request in July 2015, and will continue to advocate for further improvements through the PJM stakeholder process.

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 June 30, 2015, SWEPCo has incurred costs of $256 million, including AFUDC, and has remaining contractual construction obligations of $89 million related to these projects. SWEPCo will seek recovery of these project costs from customers through filings at the state commissions and the FERC. See "Mercury and Other Hazardous Air Pollutants (HAPs) Regulation" and "Climate Change, CO_2 Regulation and Energy Policy" sections of “Environmental Issues” below. As of June 30, 2015, the net book value of Welsh Plant, Units 1 and 3 was $484 million, before cost of removal, including materials and supplies inventory and CWIP. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

LITIGATION

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. We assess the probability of loss for each contingency and accrue a liability for cases that have a probable likelihood of loss if the loss can be estimated. For details on our regulatory proceedings and pending litigation see Note 4 - Rate Matters, 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 2014 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. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M. In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiffs' claims. Several claims remain, including the claim for breach of the participation agreement and a claim alleging breach of an implied covenant of good faith and fair dealing. In June 2015, AEGCo and I&M filed a motion for partial judgment on the claims seeking dismissal of the breach of participation agreement claim as well as any claim for indemnification of costs associated with this case. In July 2015, the plaintiffs responded to the motion for partial judgment and simultaneously moved for partial summary judgment on their claims for breach of the lease and participation agreement. We will continue to defend against the remaining claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

ENVIRONMENTAL ISSUES

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

We are engaged in litigation about environmental issues, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of SNF and future decommissioning of our nuclear units. We, along with various industry groups, affected states and other parties have challenged some of the Federal EPA requirements in court. We are also engaged in the development of 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.

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 2014 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 June 30, 2015, the AEP System had a total generating capacity of approximately 32,100 MWs, of which approximately 18,200 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 generating facilities. Based upon our estimates, investment to meet these requirements ranges from approximately $2.8 billion to $3.3 billion through 2020. These amounts include investments to convert some of our coal generation to natural gas. If natural gas conversion is not completed, 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 (SIPs) or federal implementation plans (FIPs) that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on our units, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity and (g) other factors. In addition, we are continuing to evaluate the economic feasibility of environmental investments on both regulated and nonregulated plants.

In May 2015, we retired the following plants or units of plants:

Company	Plant Name and Unit	Generating Capacity (in MWs)
AGR	Kammer Plant	630
AGR	Muskingum River Plant	1,440
AGR	Picway Plant	100
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
APCo/AGR	Sporn Plant	600
I&M	Tanners Creek Plant	995
KPCo	Big Sandy Plant, Unit 2	800
Total		5,535

As of June 30, 2015, the net book value of the AGR units listed above was zero. The book value of the regulated plants in the table above was $752 million. Of this amount, $608 million has been approved for recovery while $144 million is pending regulatory approval.

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

Company	Plant Name and Unit	Generating Capacity (in MWs)
PSO	Northeastern Station, Unit 4	470
SWEPCo	Welsh Plant, Unit 2	528
Total		998

As of June 30, 2015, the net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of the regulated plants in the table above was $178 million. Volatility in fuel prices, pending environmental rules and other market factors could also have an adverse impact on the accounting evaluation of the recoverability of the net book values of coal-fired units. For Northeastern Station, Unit 4 and Welsh Plant, Unit 2, we are seeking regulatory recovery of remaining net book values.

In addition, we are in the process of obtaining permits following the KPSC's approval for the conversion of KPCo's 278 MW Big Sandy Plant, Unit 1 to natural gas. As of June 30, 2015, the net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of Big Sandy Plant, Unit 1 was $104 million.

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 and impact financial condition.

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Clean Air Act Requirements

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

The Federal EPA issued the Clean Air Interstate Rule (CAIR) in 2005 requiring specific reductions in SO_2 and NO_x emissions from power plants. The Federal EPA issued the Cross-State Air Pollution Rule (CSAPR) in August 2011 to replace CAIR. The CSAPR was challenged in the courts. In 2012, a panel of the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing CAIR until a replacement rule is finalized. That decision was appealed to the U.S. Supreme Court, which reversed the decision and remanded the case to the U.S. Court of Appeals for the District of Columbia Circuit. The U.S. Court of Appeals for the District of Columbia Circuit ordered CSAPR to take effect on January 1, 2015 while the remand proceeding was still pending. All of the states in which our power plants are located are covered by CSAPR. See "Cross-State Air Pollution Rule (CSAPR)" section below.

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

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's requirement that certain facilities install best available retrofit technology (BART) will address regional haze in federal parks and other protected areas. BART requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through SIPs or, if SIPs are not adequate or are not developed on schedule, through FIPs. The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas. In March 2012, the Federal EPA disapproved certain portions of the Arkansas regional haze SIP. In April 2015, the Federal EPA published a proposed FIP to replace the disapproved portions, including revised BART determinations for the Flint Creek Plant that are consistent with the environmental controls currently under construction. In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the CSAPR trading programs to use those programs in place of source-specific BART for SO_2 and NO_x emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. This rule is being challenged in the U.S. Court of Appeals for the District of Columbia Circuit. In July 2015, we will submit comments to the proposed Arkansas FIP and participate in comments filed by industry associations of which we are members. We support compliance with CSAPR programs as satisfaction of the BART requirements.

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

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

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

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for units burning coal on a 30-day rolling average basis for mercury, PM (as a surrogate for particles of nonmercury metals) and hydrogen chloride (as a surrogate for acid gases). 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 was required within three years. The final rule contains a slightly less stringent PM limit for existing sources than the original proposal and the revised rule provides alternative work practice standards for operators during start-up and shut down periods. We have obtained a one-year administrative extension at several units to facilitate the installation of controls or to avoid a serious reliability problem. In addition, the Federal EPA issued an enforcement policy describing the circumstances under which an administrative consent order might be issued to provide a fifth year for the installation of controls or completion of reliability upgrades. We remain concerned about the availability of compliance extensions, the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines and the lack of coordination among the Mercury and Air Toxics Standards (MATS) schedule and other environmental requirements.

Petitions for administrative reconsideration and judicial review of the final rule were filed. In 2012, the Federal EPA published a notice announcing that it would accept comments on its reconsideration of certain issues related to the new source standards, including clarification of the requirements that apply during periods of start-up and shut down, measurement issues and the application of variability factors that may have an impact on the level of the standards. The Federal EPA issued revisions to the new source standards consistent with the proposed rule, except the start-up and shut down provisions in March 2013. A final rule on reconsideration was issued in 2014 and a proposed rule containing technical corrections was issued in early 2015. In April 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the April 2012 final rule. Industry trade groups and several states filed petitions for further review in the U.S. Supreme Court and the court granted those petitions in November 2014.

In June 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit and remanded the MATS rule for further proceedings consistent with its decision that the Federal EPA was unreasonable in refusing to consider costs in its determination whether to regulate emissions of HAPs from power plants. The case will be remanded to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings consistent with the U.S. Supreme Court's decision. We will continue to evaluate the impact of this decision and until further action by the U.S. Court of Appeals for the District of Columbia Circuit, the rule remains in place.

Climate Change, CO_2 Regulation and Energy Policy

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

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

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

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

In 2012, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision upholding, in all material respects, the Federal EPA's endangerment finding, its regulatory program for CO_2 emissions from new motor vehicles and its plan to phase in regulation of CO_2 emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. In June 2014, the U.S. Supreme Court determined that the Federal EPA was not compelled to regulate CO_2 emissions from stationary sources under the Title V or PSD programs as a result of its adoption of the motor vehicle standards, but that sources otherwise required to obtain a PSD permit may be required to perform a Best Available Control Technology (BACT) analysis for CO_2 emissions if they exceed a reasonable level. The Federal EPA removed those provisions of the final rule from the Code of Federal Regulations that were inconsistent with the U.S. Supreme Court's decision but continues to apply a 75,000 ton per year threshold to trigger the need for a BACT analysis. Petitions were filed with the U.S. Court of Appeals for the District of Columbia Circuit seeking to amend the judgment in the case to require Federal EPA to establish a reasonable minimum level. Those petitions are pending.

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

Coal Combustion Residual Rule

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

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

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

The final rule was published in the Federal Register in April 2015 and becomes effective six months after publication. We recorded a $95 million increase in asset retirement obligations in the second quarter of 2015 primarily due to the publication of the final rule. Given the future effective date of the rule and the schedule for implementation, we will continue to evaluate the rule's impact on operations.

Clean Water Act (CWA) Regulations

In 2014, the Federal EPA issued a final rule setting forth standards for existing power plants that is intended to reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. Entrainment is when small fish, eggs or larvae are drawn into the cooling water system and affected by heat, chemicals or physical stress. The final rule affects all plants withdrawing more than two million gallons of cooling water per day. The rule offers seven technology options to comply with the impingement standard and requires site-specific studies to determine appropriate entrainment compliance measures at facilities withdrawing more than

125 million gallons per day. Additional requirements may be imposed as a result of consultation with other federal agencies to protect threatened and endangered species and their habitats. Facilities with existing closed cycle recirculating cooling systems, as defined in the rule, are not expected to require any technology changes. Facilities subject to both the impingement standard and site-specific entrainment studies will typically be given at least three years to conduct and submit the results of those studies to the permit agency. Compliance timeframes will then be established by the permit agency through each facility's National Pollutant Discharge Elimination System (NPDES) permit for installation of any required technology changes, as those permits are renewed over the next five to eight years. Petitions for review of the final rule were filed by industry and environmental groups and are currently pending in the U.S. Court of Appeals for the Second Circuit.

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

In April 2014, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a proposed rule to clarify the scope of the regulatory definition of "waters of the United States" in light of recent U.S. Supreme Court cases and published the proposed rule in the Federal Register. The CWA provides for federal jurisdiction over "navigable waters" defined as "the waters of the United States." This proposed jurisdictional definition applied 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 submitted detailed comments to the Federal EPA in November 2014 and also participated in comments filed by various organizations of which we are members. In June 2015, the Federal EPA published the final rule that included a few changes from the proposal. The effective date of the rule is 60 days following publication. The final definition continues to recognize traditional navigable waters of the U.S. as jurisdictional as well as certain exclusions. The rule also contains a number of new specific definitions and criteria for determining whether certain other waters are jurisdictional because of a "significant nexus." We agree that clarity and efficiency in the permitting process is needed. We are concerned that the rule introduces new concepts and could subject more of our operations to CWA jurisdiction, thereby increasing the time and complexity of permitting. We anticipate that the final rule will be challenged in the courts.

RESULTS OF OPERATIONS

SEGMENTS

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

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by OPCo, TCC and TNC.
- OPCo purchases energy and capacity to serve SSO customers and provides transmission and distribution services for all connected load.

AEP Transmission Holdco

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

Generation & Marketing

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

AEP River Operations

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

The table below presents Earnings Attributable to AEP Common Shareholders by segment for the three and six months ended June 30, 2015 and 2014.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions)			
Vertically Integrated Utilities	$207	$154	$506	$432
Transmission and Distribution Utilities	78	90	175	187
AEP Transmission Holdco	65	47	101	71
Generation & Marketing	82	98	269	261
AEP River Operations	1	3	12	6
Corporate and Other (a)	(3)	(2)	(4)	(7)
Earnings Attributable to AEP Common Shareholders	$430	$390	$1,059	$950

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

AEP CONSOLIDATED

Second Quarter of 2015 Compared to Second Quarter of 2014

Earnings Attributable to AEP Common Shareholders increased from $390 million in 2014 to $430 million in 2015 primarily due to:

- Successful rate proceedings in various jurisdictions.
- An increase in annual formula rate adjustments.
- An increase in transmission investment which resulted in higher revenues and income.
- A decrease in employee-related expenses.
- Favorable retail, trading and marketing activity.

These increases were partially offset by:

- A decrease in generation sales due to lower capacity revenue.
- A decrease in off-system sales margins due to lower market prices and reduced sales volumes.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

Earnings Attributable to AEP Common Shareholders increased from $1.0 billion in 2014 to $1.1 billion in 2015 primarily due to:

- Successful rate proceedings in various jurisdictions.
- An increase in annual formula rate adjustments.
- An increase in transmission investment which resulted in higher revenues and income.
- A decrease in employee-related expenses.
- Favorable retail, trading and marketing activity.

These increases were partially offset by:

- A decrease in off-system sales margins due to lower market prices and reduced sales volumes.
- A decrease in generation sales due to lower capacity revenue.
- A decrease in weather normalized sales.

Our results of operations by operating segment are discussed below.

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
	(in millions)			
Revenues	$2,183	$2,252	$4,688	$4,838
Fuel and Purchased Electricity	781	934	1,764	2,028
Gross Margin	1,402	1,318	2,924	2,810
Other Operation and Maintenance	615	618	1,191	1,194
Depreciation and Amortization	266	252	538	515
Taxes Other Than Income Taxes	94	87	191	183
Operating Income	427	361	1,004	918
Interest and Investment Income	2	—	3	1
Carrying Costs Income	3	2	5	1
Allowance for Equity Funds Used During Construction	16	11	30	21
Interest Expense	(131)	(132)	(262)	(263)
Income Before Income Tax Expense and Equity Earnings	317	242	780	678
Income Tax Expense	110	88	274	245
Equity Earnings of Unconsolidated Subsidiaries	1	1	2	1
Net Income	208	155	508	434
Net Income Attributable to Noncontrolling Interests	1	1	2	2
Earnings Attributable to AEP Common Shareholders	$207	$154	$506	$432

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
	(in millions of KWhs)			
Retail:				
Residential	6,672	6,716	17,051	17,621
Commercial	6,296	6,122	12,307	12,237
Industrial	8,937	9,025	17,297	17,357
Miscellaneous	574	577	1,122	1,132
Total Retail	22,479	22,440	47,777	48,347
Wholesale (a)	5,903	8,602	14,171	18,786

(a) Includes off-system sales, municipalities and cooperatives, unit power and other wholesale 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. In general, degree day changes in our eastern region have a larger effect on revenues 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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in degree days)			
Eastern Region				
Actual – Heating (a)	93	118	2,138	2,246
Normal – Heating (b)	139	138	1,743	1,731
Actual – Cooling (c)	402	362	402	362
Normal – Cooling (b)	324	324	329	329
Western Region				
Actual – Heating (a)	9	47	1,049	1,233
Normal – Heating (b)	34	33	911	920
Actual – Cooling (c)	704	674	718	680
Normal – Cooling (b)	693	686	716	710

(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.

Second Quarter of 2015 Compared to Second Quarter of 2014
Reconciliation of Second Quarter of 2014 to Second Quarter of 2015
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Second Quarter of 2014	$154	
Changes in Gross Margin:		
Retail Margins	111	
Off-system Sales	(23	)
Transmission Revenues	1	
Other Revenues	(5	)
Total Change in Gross Margin	84	
Changes in Expenses and Other:		
Other Operation and Maintenance	3	
Depreciation and Amortization	(14	)
Taxes Other Than Income Taxes	(7	)
Interest and Investment Income	2	
Carrying Costs Income	1	
Allowance for Equity Funds Used During Construction	5	
Interest Expense	1	
Total Change in Expenses and Other	(9	)
Income Tax Expense	(22	)
Second Quarter of 2015	$207	

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 $111 million primarily due to the following:
  - The effect of successful rate proceedings in our service territories which include:
    - A $37 million increase for I&M primarily due to rate increases from Indiana rate riders and annual formula rate adjustments.
    - A $33 million increase for SWEPCo primarily due to increases in municipal and cooperative revenues due to annual formula rate adjustments and revenue increases from SWEPCo rate riders in Louisiana and Texas.
    - An $18 million increase primarily due to rate increases in Virginia and West Virginia, offset by a decrease in annual formula rates.
    - A $7 million increase for PSO primarily due to revenue increases from rate riders.

  For the increases described above, $14 million relate to riders/trackers which have corresponding increases in expense items below.
- Margins from Off-system Sales decreased $23 million primarily due to lower market prices and decreased sales volumes.
- Other Revenues decreased $5 million primarily due to a decrease in River Transportation Division (RTD) barging resulting from reduced deliveries to the Rockport Plant. This decrease in RTD revenue has a corresponding decrease in Other Operation and Maintenance expenses for barging as discussed below.

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

- Other Operation and Maintenance expenses decreased $3 million primarily due to the following:
  - A $16 million decrease in employee-related expenses.
  - A $15 million decrease in storm expenses and vegetation management expenses primarily in the APCo region.
  - A $4 million decrease in uncollectible accounts expense due to the establishment of a regulatory asset for recovery in the May 2015 West Virginia base case order.

  These decreases were partially offset by:
  - A $13 million increase in nuclear expenses.
  - A $14 million increase in recoverable expenses, primarily including PJM expenses currently fully recovered in rate recovery riders/trackers partially offset by lower RTD barging costs.
  - A $5 million increase in SPP and PJM transmission services expenses.
- Depreciation and Amortization expenses increased $14 million primarily due to overall higher depreciable base and amortization related to an advanced metering rider implemented in November 2014 in Oklahoma.
- Taxes Other Than Income Taxes increased $7 million primarily due to an increase in property taxes.
- Allowance for Equity Funds Used During Construction increased $5 million primarily due to increases in environmental construction and transmission projects.
- Income Tax Expense increased $22 million primarily due an increase in pretax book income partially offset by the regulatory accounting treatment of state income taxes.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014
Reconciliation of Six Months Ended June 30, 2014 to Six Months Ended June 30, 2015
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Six Months Ended June 30, 2014	$432	
Changes in Gross Margin:		
Retail Margins	212	
Off-system Sales	(95	)
Transmission Revenues	1	
Other Revenues	(4	)
Total Change in Gross Margin	114	
Changes in Expenses and Other:		
Other Operation and Maintenance	3	
Depreciation and Amortization	(23	)
Taxes Other Than Income Taxes	(8	)
Interest and Investment Income	2	
Carrying Costs Income	4	
Allowance for Equity Funds Used During Construction	9	
Interest Expense	1	
Total Change in Expenses and Other	(12	)
Income Tax Expense	(29	)
Equity Earnings	1	
Six Months Ended June 30, 2015	$506	

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

- Retail Margins increased $212 million primarily due to the following:
- The effect of successful rate proceedings in our service territories which include:
- A $68 million increase primarily due to rate increases in Virginia and West Virginia, including an adjustment due to the amended Virginia law affecting biennial reviews.
- A $54 million increase for I&M primarily due to rate increases from Indiana rate riders and annual formula rate adjustments.
- A $43 million increase for SWEPCo primarily due to increases in municipal and cooperative revenues due to annual formula rate adjustments and revenue increases from SWEPCo rate riders in Louisiana and Texas.
- A $16 million increase for PSO primarily due to revenue increases from rate riders.

For the increases described above, $47 million relate to riders/trackers which have corresponding increases in expense items below.

- A $31 million decrease in PJM expenses net of recovery or offsets.

These increases were partially offset by:

- A $34 million decrease in weather-normalized load primarily due to lower residential sales in the eastern region.
- Margins from Off-system Sales decreased $95 million primarily due to lower market prices and decreased sales volumes.
-

Other Revenues decreased $4 million primarily due to a decrease in River Transportation Division (RTD) barging resulting from reduced deliveries to the Rockport Plant. This decrease in RTD revenue has a corresponding decrease in Other Operation and Maintenance expenses for barging as discussed below.

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

- Other Operation and Maintenance expenses decreased $3 million primarily due to the following:
  - A $38 million decrease in employee-related expenses.
  - A $12 million decrease in storm expenses and vegetation management expenses primarily in the APCo region.

  These decreases were partially offset by:
  - A $38 million increase in recoverable expenses, primarily including PJM expenses currently fully recovered in rate recovery riders/trackers partially offset by lower RTD barging costs.
  - A $7 million increase in PJM transmission services expenses.
- Depreciation and Amortization expenses increased $23 million primarily due to overall higher depreciable base and amortization related to an advanced metering rider implemented in November 2014 in Oklahoma.
- Taxes Other Than Income Taxes increased $8 million primarily due to an increase in property taxes.
- Allowance for Equity Funds Used During Construction increased $9 million primarily due to increases in environmental construction and transmission projects.
- Income Tax Expense increased $29 million primarily due an increase in pretax book income partially offset by the regulatory accounting treatment of state income taxes.

TRANSMISSION AND DISTRIBUTION UTILITIES

	Three Months Ended June 30,		Six Months Ended June 30,	
Transmission and Distribution Utilities	2015	2014	2015	2014
	(in millions)			
Revenues	$1,061	$1,134	$2,331	$2,349
Fuel and Purchased Electricity	270	343	691	746
Amortization of Generation Deferrals	36	25	67	56
Gross Margin	755	766	1,573	1,547
Other Operation and Maintenance	289	298	608	591
Depreciation and Amortization	170	156	338	317
Taxes Other Than Income Taxes	118	108	240	227
Operating Income	178	204	387	412
Interest and Investment Income	1	3	3	6
Carrying Costs Income	6	7	12	14
Allowance for Equity Funds Used During Construction	4	2	8	5
Interest Expense	(68)	(72)	(138)	(142)
Income Before Income Tax Expense	121	144	272	295
Income Tax Expense	43	54	97	108
Net Income	78	90	175	187
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$78	$90	$175	$187

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions of KWhs)			
Retail:				
Residential	5,630	5,559	12,896	13,086
Commercial	6,372	6,314	12,287	12,216
Industrial	5,809	5,630	11,089	10,773
Miscellaneous	177	182	338	353
Total Retail (a)	17,988	17,685	36,610	36,428
Wholesale (b)	429	453	963	1,152

(a) Represents energy delivered to distribution customers.
(b) Ohio's contractually obligated purchases of OVEC power sold into PJM.

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. In general, degree day changes in our eastern region have a larger effect on revenues 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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in degree days)			
Eastern Region				
Actual – Heating (a)	137	130	2,575	2,539
Normal – Heating (b)	186	187	2,067	2,067
Actual – Cooling (c)	350	362	350	362
Normal – Cooling (b)	287	280	290	283
Western Region				
Actual – Heating (a)	—	2	320	302
Normal – Heating (b)	4	4	192	200
Actual – Cooling (d)	863	872	904	942
Normal – Cooling (b)	917	904	1,026	1,012

(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.

Second Quarter of 2015 Compared to Second Quarter of 2014
Reconciliation of Second Quarter of 2014 to Second Quarter of 2015
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Second Quarter of 2014	$90	
Changes in Gross Margin:		
Retail Margins	13	
Off-system Sales	(5	)
Transmission Revenues	(25	)
Other Revenues	6	
Total Change in Gross Margin	(11	)
Changes in Expenses and Other:		
Other Operation and Maintenance	9	
Depreciation and Amortization	(14	)
Taxes Other Than Income Taxes	(10	)
Interest and Investment Income	(2	)
Carrying Costs Income	(1	)
Allowance for Equity Funds Used During Construction	2	
Interest Expense	4	
Total Change in Expenses and Other	(12	)
Income Tax Expense	11	
Second Quarter of 2015	$78	

The major components of the decrease 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 $13 million primarily due to the following:
  - A $14 million increase in transmission rider and PJM retail revenues primarily due to CRES transmission revenue collected through a non-bypassable retail transmission rider beginning in June 2015, which is partially offset by a corresponding decrease in Transmission Revenues below.
  - A $7 million increase in revenues associated with the Ohio Distribution Investment Rider (DIR).
  - A $6 million increase in TCC and TNC revenues primarily due to the recovery of ERCOT transmission expenses, which is offset in Other Operation and Maintenance expenses below.
  - A $4 million increase in industrial sales in Ohio.

  These increases were partially offset by:
  - A $12 million decrease in revenues associated with the Ohio Storm Damage Recovery Rider which started in April 2014 and ended in April 2015. This decrease in Retail Margins is primarily offset by a decrease in Other Operation and Maintenance expenses below.
  - An $8 million decrease in the Energy Efficiency (EE), Peak Demand Reduction Cost Recovery Rider (PDR) revenues in Ohio. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
- Margins from Off-system Sales decreased $5 million primarily due to lower margins on PJM liquidations on a legacy OPCo power contract and lower Oklaunion purchased power agreement (PPA) revenues.
- Transmission Revenues decreased $25 million primarily due to:
  - A $12 million decrease in Ohio revenues related to a lower transmission formula rate true-up than in the prior year.

- A $10 million decrease in Network Integrated Transmission Service (NITS) revenue due to OPCo assuming the responsibility for items determined to be cost-based transmission-related charges that were the responsibility of the CRES providers prior to June 2015, which is partially offset by a corresponding increase in Retail Margins above.

- A $7 million OPCo transmission regulatory loss provision in 2015.

These decreases were partially offset by:

- A $7 million increase primarily due to increased transmission investment in ERCOT.
- Other Revenues increased $6 million primarily due to $3 million of increased pole attachment revenue for OPCo and $2 million in Texas securitization revenues which is offset in Depreciation and Amortization below.

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

- Other Operation and Maintenance expenses decreased $9 million primarily due to the following:
- A $12 million decrease due to the completion of the amortization of Ohio 2012 deferred storm expenses. This decrease was offset by a corresponding decrease in Retail Margins above.
- An $8 million decrease in EE and PDR expenses. This decrease was offset by a corresponding decrease in Retail Margins above.
- A $5 million decrease in employee-related expenses.

These decreases were partially offset by:

- A $9 million increase in PJM and ERCOT transmission services expenses.
- A $6 million increase in storm expenses primarily in the Texas region.
- Depreciation and Amortization expenses increased $14 million primarily due to the following:
- An $8 million increase due to an increase in the depreciable base of transmission and distribution assets.
- A $4 million increase in amortization of TCC's securitization transition asset, which is partially offset in Other Revenues.
- Taxes Other Than Income Taxes increased $10 million primarily due to an increase in property taxes.
- Interest Expense decreased $4 million primarily due to reduced TCC long-term debt outstanding, which is partially offset in Other Revenues.
- Income Tax Expense decreased $11 million primarily due to a decrease in pretax book income and the regulatory accounting treatment of state income taxes.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014
Reconciliation of Six Months Ended June 30, 2014 to Six Months Ended June 30, 2015
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Six Months Ended June 30, 2014	$ 187
Changes in Gross Margin:	
Retail Margins	44
Off-system Sales	(4)
Transmission Revenues	(21)
Other Revenues	7
Total Change in Gross Margin	26
Changes in Expenses and Other:	
Other Operation and Maintenance	(17)
Depreciation and Amortization	(21)
Taxes Other Than Income Taxes	(13)
Interest and Investment Income	(3)
Carrying Costs Income	(2)
Allowance for Equity Funds Used During Construction	3
Interest Expense	4
Total Change in Expenses and Other	(49)
Income Tax Expense	11
Six Months Ended June 30, 2015	$ 175

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 $44 million primarily due to the following:
  - A $23 million increase in TCC and TNC revenues primarily due to the recovery of ERCOT transmission expenses, which is offset in Other Operation and Maintenance expenses below.
  - A $15 million increase in revenues associated with the Ohio Distribution Investment Rider (DIR).
  - A $14 million increase in transmission rider and PJM retail revenues primarily due to CRES transmission revenue collected through a non-bypassable retail transmission rider beginning in June 2015, which is partially offset by a corresponding decrease in Transmission Revenues below.
  - A $10 million increase in Ohio base rates due to the discontinuance of seasonal rates.

  These increases were partially offset by:
  - A $17 million decrease in the Energy Efficiency (EE), Peak Demand Reduction Cost Recovery Rider (PDR) revenues in Ohio. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
- Margins from Off-system Sales decreased $4 million primarily due to lower margins on PJM liquidations on a legacy OPCo power contract and lower Oklaunion PPA revenues.
- Transmission Revenues decreased $21 million primarily due to:
  - A $12 million decrease in Ohio revenues related to a lower transmission formula rate true-up than in the prior year.
  - A $10 million decrease in NITS revenue due to OPCo assuming the responsibility for items determined to be cost-based transmission-related charges that were the responsibility of the CRES providers prior to June 2015, which is partially offset by a corresponding increase in Retail Margins above.

- A $7 million OPCo transmission regulatory loss provision in 2015.

These decreases were partially offset by:

- An $11 million increase primarily due to increased transmission investment in ERCOT.
- Other Revenues increased $7 million primarily due to $4 million of increased pole attachment revenue for OPCo and a $2 million increase in Texas securitization revenues which is offset in Depreciation and Amortization below.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $17 million primarily due to the following:
- A $17 million increase in recoverable ERCOT transmission expenses currently recovered dollar-for-dollar in rate recovery riders/trackers.
- A $14 million increase in PJM transmission services expenses.
- A $13 million increase in distribution expenses including system improvements and storm expenses.
- A $6 million increase due to PUCO ordered contributions to the Ohio Growth Fund.

These increases were partially offset by:
- A $17 million decrease in EE and PDR costs and associated deferrals. This decrease was offset by a corresponding decrease in Retail Margins above.
- An $11 million decrease in employee-related expenses.
- Depreciation and Amortization expenses increased $21 million primarily due to the following:
- A $12 million increase due to an increase in the depreciable base of transmission and distribution assets.
- A $7 million increase in amortization of TCC's securitization transition asset, which is partially offset in Other Revenues.
- Taxes Other Than Income Taxes increased $13 million primarily due to increased property taxes.
- Interest Expense decreased $4 million primarily due to reduced TCC long-term debt outstanding, which is partially offset in Other Revenues.
- Income Tax Expense decreased $11 million primarily due to a decrease in pretax book income and by the regulatory accounting treatment of state income taxes.

AEP TRANSMISSION HOLDCO

AEP Transmission Holdco	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
	(in millions)			
Transmission Revenues	$99	$57	$157	$85
Other Operation and Maintenance	8	6	16	11
Depreciation and Amortization	9	6	18	11
Taxes Other Than Income Taxes	17	6	33	13
Operating Income	65	39	90	50
Allowance for Equity Funds Used During Construction	14	12	26	21
Interest Expense	(9)	(5)	(17)	(10)
Income Before Income Tax Expense and Equity Earnings	70	46	99	61
Income Tax Expense	29	22	43	30
Equity Earnings of Unconsolidated Subsidiaries	24	23	46	40
Net Income	65	47	102	71
Net Income Attributable to Noncontrolling Interests	—	—	1	—
Earnings Attributable to AEP Common Shareholders	$65	$47	$101	$71

Summary of Net Plant in Service and CWIP for AEP Transmission Holdco

	As of June 30, 2015	2014
	(in millions)	
Net Plant in Service	$2,111	$1,167
CWIP	1,130	895

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Second Quarter of 2015 Compared to Second Quarter of 2014

Reconciliation of Second Quarter of 2014 to Second Quarter of 2015
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Second Quarter of 2014	$47	
Changes in Transmission Revenues:		
Transmission Revenues	42	
Total Change in Transmission Revenues	42	
Changes in Expenses and Other:		
Other Operation and Maintenance	(2	)
Depreciation and Amortization	(3	)
Taxes Other Than Income Taxes	(11	)
Allowance for Equity Funds Used During Construction	2	
Interest Expense	(4	)
Total Change in Expenses and Other	(18	)
Income Tax Expense	(7	)
Equity Earnings	1	
Second Quarter of 2015	$65	

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

- Transmission Revenues increased $42 million primarily due to an increase in projects placed in-service by our wholly-owned transmission subsidiaries.

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

- Other Operation and Maintenance expenses increased $2 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $3 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $11 million primarily due to increased property taxes.
- Allowance for Equity Funds Used During Construction increased $2 million primarily due to increased transmission investment.
- Interest Expense increased $4 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $7 million primarily due to an increase in pretax book income.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

Reconciliation of Six Months Ended June 30, 2014 to Six Months Ended June 30, 2015
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Six Months Ended June 30, 2014	$71
Changes in Transmission Revenues:	
Transmission Revenues	72
Total Change in Transmission Revenues	72
Changes in Expenses and Other:	
Other Operation and Maintenance	(5)
Depreciation and Amortization	(7)
Taxes Other Than Income Taxes	(20)
Allowance for Equity Funds Used During Construction	5
Interest Expense	(7)
Total Change in Expenses and Other	(34)
Income Tax Expense	(13)
Equity Earnings	6
Net Income Attributable to Noncontrolling Interests	(1)
Six Months Ended June 30, 2015	$101

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

- Transmission Revenues increased $72 million primarily due to an increase in projects placed in-service by our wholly-owned transmission subsidiaries.

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

- Other Operation and Maintenance expenses increased $5 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $7 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $20 million primarily due to increased property taxes.
- Allowance for Equity Funds Used During Construction increased $5 million primarily due to increased transmission investment.
- Interest Expense increased $7 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $13 million primarily due to an increase in pretax book income.
- Equity Earnings increased $6 million primarily due to increased transmission investment by ETT.

GENERATION & MARKETING

Generation & Marketing	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
	(in millions)			
Revenues	$801	$913	$1,971	$2,164
Fuel, Purchased Electricity and Other	491	560	1,207	1,365
Gross Margin	310	353	764	799
Other Operation and Maintenance	116	125	216	241
Depreciation and Amortization	51	56	101	113
Taxes Other Than Income Taxes	11	13	20	25
Operating Income	132	159	427	420
Interest and Investment Income	1	1	2	2
Interest Expense	(10)	(11)	(21)	(23)
Income Before Income Tax Expense	123	149	408	399
Income Tax Expense	41	51	139	138
Net Income	82	98	269	261
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$82	$98	$269	$261

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
	(in millions of MWhs)			
Fuel Type:				
Coal	6	9	16	21
Natural Gas	3	2	7	4
Total MWhs	9	11	23	25

Second Quarter of 2015 Compared to Second Quarter of 2014
Reconciliation of Second Quarter of 2014 to Second Quarter of 2015
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Second Quarter of 2014	$98	
Changes in Gross Margin:		
Generation	(53	)
Retail, Trading and Marketing	12	
Other	(2	)
Total Change in Gross Margin	(43	)
Changes in Expenses and Other:		
Other Operation and Maintenance	9	
Depreciation and Amortization	5	
Taxes Other Than Income Taxes	2	
Interest Expense	1	
Total Change in Expenses and Other	17	
Income Tax Expense	10	
Second Quarter of 2015	$82	

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

- Generation decreased $53 million primarily due to lower capacity revenue due to the termination of the Power Supply Agreement between AGR and OPCo.
- Retail, Trading and Marketing increased $12 million primarily due to an increase in retail volumes.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $9 million primarily due to a decrease in plant outage and maintenance costs.
- Depreciation and Amortization expenses decreased $5 million primarily due to reduced plant in service.
- Income Tax Expense decreased $10 million primarily due to a decrease in pretax book income.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014
Reconciliation of Six Months Ended June 30, 2014 to Six Months Ended June 30, 2015
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Six Months Ended June 30, 2014	$261
Changes in Gross Margin:	
Generation	(77)
Retail, Trading and Marketing	46
Other	(4)
Total Change in Gross Margin	(35)
Changes in Expenses and Other:	
Other Operation and Maintenance	25
Depreciation and Amortization	12
Taxes Other Than Income Taxes	5
Interest Expense	2
Total Change in Expenses and Other	44
Income Tax Expense	(1)
Six Months Ended June 30, 2015	$269

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

- Generation decreased $77 million primarily due to lower capacity revenue due to the termination of the Power Supply Agreement between AGR and OPCo.
- Retail, Trading and Marketing increased $46 million primarily due to favorable wholesale trading and marketing performance as well as an increase in retail volumes.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $25 million primarily due to a decrease in plant outage and maintenance costs.
- Depreciation and Amortization expenses decreased $12 million primarily due to reduced plant in service.
- Taxes Other Than Income Taxes decreased $5 million primarily due to a decrease in property taxes.

AEP RIVER OPERATIONS

Second Quarter of 2015 Compared to Second Quarter of 2014

Earnings Attributable to AEP Common Shareholders from our AEP River Operations segment decreased from $3 million in 2014 to $1 million in 2015 primarily due to lower freight revenue compared to second quarter 2014 resulting from various high water operating restrictions during the quarter.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

Earnings Attributable to AEP Common Shareholders from our AEP River Operations segment increased from $6 million in 2014 to $12 million in 2015 primarily due to lower fuel prices and reduced consumption, partially offset by lower freight revenue.

CORPORATE AND OTHER

Second Quarter of 2015 Compared to Second Quarter of 2014

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $2 million in 2014 to a loss of $3 million in 2015 primarily due to increased income tax expense of $1 million primarily due to book/tax differences which are accounted for on a flow-through basis.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from a loss of $7 million in 2014 to a loss of $4 million in 2015 primarily due to book/tax differences which are accounted for on a flow-through basis.

AEP SYSTEM INCOME TAXES

Second Quarter of 2015 Compared to Second Quarter of 2014

Income Tax Expense increased $10 million primarily due to an increase in pretax book income partially offset by the regulatory accounting treatment of state income taxes.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

Income Tax Expense increased $36 million primarily due to an increase in pretax book income partially offset by the regulatory accounting treatment of state income taxes.

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

	June 30, 2015	December 31, 2014
	(dollars in millions)	

Long-term Debt, including amounts due within one year	$19,578	51.4	%	$18,684	50.7	%
Short-term Debt	1,105	2.9		1,346	3.6	
Total Debt	20,683	54.3		20,030	54.3	
AEP Common Equity	17,434	45.7		16,820	45.7	
Noncontrolling Interests	8	—		4	—	
Total Debt and Equity Capitalization	$38,125	100.0	%	$36,854	100.0	%

Our ratio of debt-to-total capital remained unchanged at 54.3% as of December 31, 2014 and June 30, 2015.

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 June 30, 2015, 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 June 30, 2015, our available liquidity was approximately $3.2 billion as illustrated in the table below:

		Amount (in millions)	Maturity
Commercial Paper Backup:			
	Revolving Credit Facility	$ 1,750	June 2017
	Revolving Credit Facility	1,750	July 2018
Total		3,500	
Cash and Cash Equivalents		195	
Total Liquidity Sources		3,695	
Less:	AEP Commercial Paper Outstanding	397	
	Letters of Credit Issued	61	
Net Available Liquidity		$ 3,237	

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 six months of 2015 was $788 million. The weighted-average interest rate for our commercial paper during 2015 was 0.46%.

Other Credit Facilities

We issue letters of credit under a $100 million uncommitted facility. As of June 30, 2015, the maximum future payment for letters of credit issued under the uncommitted facility was $100 million with a maturity date of December 2015. 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 $750 million from bank conduits to purchase receivables. The agreement expires in June 2017.

Debt Covenants and Borrowing Limitations

Our credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually defined in our credit agreements. Debt as defined in the revolving credit agreements excludes securitization bonds and debt of AEP Credit. As of June 30, 2015, this contractually-defined percentage was 51.4%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of June 30, 2015, 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 and we manage our borrowings to stay within those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.53 per share in July 2015. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Our income 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.

	Six Months Ended June 30,	
	2015	2014
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$163	$118
Net Cash Flows from Operating Activities	2,203	2,197

Net Cash Flows Used for Investing Activities	(2,190)	(2,068)
Net Cash Flows from (Used for) Financing Activities	19	(57)
Net Increase in Cash and Cash Equivalents	32	72
Cash and Cash Equivalents at End of Period	$195	$190

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

Operating Activities

	Six Months Ended June 30,	
	2015	2014
	(in millions)	
Net Income	$1,062	$952
Depreciation and Amortization	1,011	934
Other	130	311
Net Cash Flows from Operating Activities	$2,203	$2,197

Net Cash Flows from Operating Activities were $2.2 billion in 2015 consisting primarily of Net Income of $1.1 billion and $1 billion of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Deferred Income Taxes increased primarily due to provisions in the Taxpayer Relief Act of 2014 and an increase in tax/book temporary differences from operations. The reduction in Fuel, Materials and Supplies balances reflects a decrease in fuel inventory due to the cold winter weather, increased generation and plants retired during the second quarter of 2015.

Net Cash Flows from Operating Activities were $2.2 billion in 2014 consisting primarily of Net Income of $952 million and $934 million of noncash Depreciation and Amortization partially offset by $105 million of net fuel cost deferrals and $99 million of net 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, Materials and Supplies balances reflects a decrease in fuel inventory due to the cold winter weather and increased generation.

Investing Activities

	Six Months Ended June 30,	
	2015	2014
	(in millions)	
Construction Expenditures	$(2,182)	$(1,883)
Acquisitions of Nuclear Fuel	(52)	(58)
Acquisitions of Assets/Businesses	(2)	(45)
Other	46	(82)
Net Cash Flows Used for Investing Activities	$(2,190)	$(2,068)

Net Cash Flows Used for Investing Activities were $2.2 billion in 2015 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Net Cash Flows Used for Investing Activities were $2.1 billion in 2014 primarily due to Construction Expenditures for environmental, distribution and transmission investments. We also purchased transmission assets for $38 million.

Financing Activities

	Six Months Ended June 30,	
	2015	2014
	(in millions)	
Issuance of Common Stock, Net	$56	$29
Issuance of Debt, Net	635	459
Dividends Paid on Common Stock	(522)	(490)
Other	(150)	(55)
Net Cash Flows from (Used for) Financing Activities	$19	$(57)

Net Cash Flows from Financing Activities in 2015 were $19 million. Our net debt issuances were $635 million. The net issuances included issuances of $1.7 billion of senior unsecured notes, $140 million of pollution control bonds and $729 million of other debt notes offset by retirements of $754 million of senior unsecured and other debt notes, $180 million of securitization bonds, $140 million of pollution control bonds and $654 of other debt notes and a decrease in short term borrowing of $241 million. We paid common stock dividends of $522 million. Other includes a make whole premium payment on the extinguishment of long-term debt of $93 million in addition to capital lease principal payments of $57 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 2014 were $57 million. Our net debt issuances were $459 million. The net issuances included issuances of $530 million of senior unsecured notes, $304 million of pollution control bonds and $114 million of other debt notes and an increase in short-term borrowing of $725 million offset by retirements of $794 million of senior unsecured and other debt notes, $273 million of pollution control bonds and $138 million of securitization bonds. We paid common stock dividends of $490 million. See Note 11 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

In July 2015, OPCo retired $23 million of Securitization Bonds.

In July 2015, SWEPCo retired $150 million of 4.9% Senior Unsecured Notes due in 2015.

In July 2015, TCC retired $94 million of Securitization Bonds.

BUDGETED CONSTRUCTION EXPENDITURES

In July 2015, we increased our forecast for construction expenditures by $200 million to approximately $4.6 billion for 2015. The increase is primarily for transmission investment in the Vertically Integrated Utilities, Transmission and Distribution Utilities, and AEP Transmission Holdco segments.

OFF-BALANCE SHEET ARRANGEMENTS

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

	June 30, 2015	December 31, 2014
	(in millions)	
Rockport Plant, Unit 2 Future Minimum Lease Payments	$1,110	$1,184
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 2014 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of our contractual obligations is included in our 2014 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 2014 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

New Accounting Pronouncements Adopted During the First Quarter of 2015

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

Pronouncements Effective in the Future

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

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

The FASB issued ASU 2015-03 "Simplifying the Presentation of Debt Issuance Costs" to simplify the presentation of debt issuance costs on the balance sheets. Under the new standard, debt issuance costs related to a recognized debt liability will be presented on the balance sheets as a direct deduction from the carrying amount of that debt liability, consistent with discounts. We include debt issuance costs in Deferred Charges and Other Noncurrent Assets on the condensed balance sheets. Debt issuance costs represent less than 1% of total long-term debt. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. We intend to early adopt ASU 2015-03 for the 2015 Form 10-K.

The FASB issued ASU 2015-05 “Customer's Accounting for Fees Paid in a Cloud Computing Arrangement” to provide guidance to customers about whether a cloud computing arrangement includes a software license. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. We are analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. We plan to adopt ASU 2015-05 effective January 1, 2016.

The FASB issued ASU 2015-11 “Simplifying the Measurement of Inventory” to simplify the guidance on the subsequent measurement of inventory, excluding inventory measured using last-in, first out or the retail inventory method. Under the new standard, inventory should be at the lower of cost and net realizable value. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016 with early adoption permitted. We are analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. We plan to adopt ASU 2015-11 effective January 1, 2017.

Future Accounting Changes

The FASB’s standard-setting process is ongoing and until new standards have been finalized and issued, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including financial instruments, leases, insurance, hedge accounting and consolidation policy. The ultimate pronouncements resulting from these and future projects could have an impact on 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 was exposed to FTR price risk as it related to RTO congestion during the June 2012 - May 2015 Ohio ESP period. Additional risks include energy procurement risk and interest rate risk.

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

We employ risk management contracts including physical forward purchase-and-sale contracts and financial forward purchase-and-sale contracts. We engage in risk management of power, coal, natural gas and, to a lesser extent, heating oil, gasoline, diesel 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 reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer. The Competitive Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, and Chief Risk Officer in addition to Energy Supply's President and Vice President. When commercial activities exceed predetermined limits, we modify the positions to reduce the risk to be within the limits unless specifically approved by the respective committee.

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2014:
MTM Risk Management Contract Net Assets (Liabilities)
Six Months Ended June 30, 2015

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
	(in millions)			
Total MTM Risk Management Contract Net Assets as of December 31, 2014	$36	$46	$140	$222
Gain from Contracts Realized/Settled During the Period and Entered in a Prior Period	(28)	(6)	(9)	(43)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	52	52
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	8	8
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	43	(3)	—	40
Total MTM Risk Management Contract Net Assets as of June 30, 2015	$51	$37	$191	279
Commodity Cash Flow Hedge Contracts				(9)
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				(1)
Fair Value Hedge Contracts				(3)
Collateral Deposits				24
Elimination of Affiliated MTM Risk Management Contracts				(7)
Total MTM Derivative Contract Net Assets as of June 30, 2015				$283

(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.

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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 June 30, 2015, our credit exposure net of collateral to sub investment grade counterparties was approximately 7.8%, 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 June 30, 2015, 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	$678	$—	$678	2	$254
Split Rating	23	—	23	1	23
Noninvestment Grade	2	—	2	2	2
No External Ratings:					
Internal Investment Grade	110	—	110	3	62
Internal Noninvestment Grade	84	17	67	2	35
Total as of June 30, 2015	$897	$17	$880	10	$376
Total as of December 31, 2014	$817	$21	$796	8	$347

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 June 30, 2015, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

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

VaR Model
Trading Portfolio

Six Months Ended June 30, 2015				Twelve Months Ended December 31, 2014			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$—	$1	$—	$—	$—	$3	$1	$—

VaR Model
Non-Trading Portfolio

Six Months Ended June 30, 2015				Twelve Months Ended December 31, 2014			
End	High	Average	Low	End	High	Average	Low

(in millions)				(in millions)			
$1	$2	$1	$—	$2	$3	$1	$—

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

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

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which our interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of June 30, 2015 and December 31, 2014, the estimated EaR on our debt portfolio for the following twelve months was $37 million and $33 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2015 and 2014
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
REVENUES				
Vertically Integrated Utilities	$2,159	$2,236	$4,646	$4,785
Transmission and Distribution Utilities	1,008	1,064	2,214	2,225
Generation & Marketing	628	573	1,487	1,394
Other Revenues	147	171	303	288
TOTAL REVENUES	3,942	4,044	8,650	8,692
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	756	1,043	1,827	2,211
Purchased Electricity for Resale	601	473	1,319	1,111
Other Operation	695	760	1,441	1,540
Maintenance	333	340	627	632
Depreciation and Amortization	506	443	1,011	934
Taxes Other Than Income Taxes	242	218	492	456
TOTAL EXPENSES	3,133	3,277	6,717	6,884
OPERATING INCOME	809	767	1,933	1,808
Other Income (Expense):				
Interest and Investment Income	3	3	4	4
Carrying Costs Income	9	9	17	15
Allowance for Equity Funds Used During Construction	34	25	64	47
Interest Expense	(224)	(221)	(447)	(441)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	631	583	1,571	1,433
Income Tax Expense	225	215	558	522
Equity Earnings of Unconsolidated Subsidiaries	25	23	49	41
NET INCOME	431	391	1,062	952
Net Income Attributable to Noncontrolling Interests	1	1	3	2
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$430	$390	$1,059	$950
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	490,207,482	488,291,576	489,904,417	488,080,505

TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.88	$0.80	$2.16	$1.95
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	490,484,450	488,538,227	490,212,271	488,405,869
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.88	$0.80	$2.16	$1.95
CASH DIVIDENDS DECLARED PER SHARE	$0.53	$0.50	$1.06	$1.00

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 49.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2015 and 2014
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net Income	$431	$391	$1,062	$952
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $1 for the Three Months Ended June 30, 2015 and 2014, Respectively, and $3 and $4 for the Six Months Ended June 30, 2015 and 2014, Respectively	1	3	(5)	8
Securities Available for Sale, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2015 and 2014, Respectively, and $0 and $0 for the Six Months Ended June 30, 2015 and 2014, Respectively	(1)	1	—	1
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $1 for the Three Months Ended June 30, 2015 and 2014, Respectively, and $0 and $1 for the Six Months Ended June 30, 2015 and 2014, Respectively	1	1	1	2
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	1	5	(4)	11
TOTAL COMPREHENSIVE INCOME	432	396	1,058	963
Total Comprehensive Income Attributable to Noncontrolling Interests	1	1	3	2
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$431	$395	$1,055	$961

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 49.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Six Months Ended June 30, 2015 and 2014
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock				Accumulated		
	Shares	Amount	Paid-in Capital	Retained Earnings	Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY - DECEMBER 31, 2013	508	$3,303	$6,131	$6,766	$(115)	$1	$16,086
Issuance of Common Stock	1	5	24				29
Common Stock Dividends				(488)		(2)	(490)
Other Changes in Equity				(6)		3	(3)
Net Income				950		2	952
Other Comprehensive Income					11		11
TOTAL EQUITY - JUNE 30, 2014	509	$3,308	$6,155	$7,222	$(104)	$4	$16,585
TOTAL EQUITY - DECEMBER 31, 2014	510	$3,313	$6,204	$7,406	$(103)	$4	$16,824
Issuance of Common Stock	1	8	48				56
Common Stock Dividends				(520)		(2)	(522)
Other Changes in Equity			1			3	4
Deferred State Income Tax Rate Adjustment			17				17
Net Income				1,059		3	1,062
Other Comprehensive Loss					(4)		(4)
Pension and OPEB Adjustment Related to Mitchell Plant					5		5
TOTAL EQUITY - JUNE 30, 2015	511	$3,321	$6,270	$7,945	$(102)	$8	$17,442

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 49.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2015 and December 31, 2014
(in millions)
(Unaudited)

	June 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$195	$163
Other Temporary Investments (June 30, 2015 and December 31, 2014 Amounts Include $344 and $371, Respectively, Related to Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and EIS)	356	386
Accounts Receivable:		
Customers	815	727
Accrued Unbilled Revenues	64	146
Pledged Accounts Receivable – AEP Credit	997	987
Miscellaneous	71	87
Allowance for Uncollectible Accounts	(27)	(21)
Total Accounts Receivable	1,920	1,926
Fuel	424	587
Materials and Supplies	736	738
Risk Management Assets	172	178
Regulatory Asset for Under-Recovered Fuel Costs	125	127
Margin Deposits	87	95
Prepayments and Other Current Assets	210	278
TOTAL CURRENT ASSETS	4,225	4,478
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	25,619	25,727
Transmission	13,020	12,433
Distribution	17,594	17,157
Other Property, Plant and Equipment (June 30, 2015 and December 31, 2014 Amounts Include Plant to be Retired, Coal Mining and Nuclear Fuel, December 31, 2014 Amount Includes 2015 Plant Retirement)	4,718	5,770
Construction Work in Progress	3,651	3,218
Total Property, Plant and Equipment	64,602	64,305
Accumulated Depreciation and Amortization	19,589	20,188
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	45,013	44,117
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,021	4,264
Securitized Assets	1,931	2,072
Spent Nuclear Fuel and Decommissioning Trusts	2,106	2,096
Goodwill	91	91
Long-term Risk Management Assets	363	294
Deferred Charges and Other Noncurrent Assets	2,188	2,221

TOTAL OTHER NONCURRENT ASSETS	11,700	11,038
TOTAL ASSETS	$60,938	$59,633

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 49.

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
June 30, 2015 and December 31, 2014
(dollars in millions)
(Unaudited)

	June 30, 2015	December 31, 2014
CURRENT LIABILITIES		
Accounts Payable	$1,236	$1,287
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	708	744
Other Short-term Debt	397	602
Total Short-term Debt	1,105	1,346
Long-term Debt Due Within One Year (June 30, 2015 and December 31, 2014 Amounts Include $463 and $431, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Sabine)	1,817	2,503
Risk Management Liabilities	78	92
Customer Deposits	335	324
Accrued Taxes	749	871
Accrued Interest	232	239
Regulatory Liability for Over-Recovered Fuel Costs	39	55
Other Current Liabilities	1,059	1,250
TOTAL CURRENT LIABILITIES	6,650	7,967
NONCURRENT LIABILITIES		
Long-term Debt (June 30, 2015 and December 31, 2014 Amounts Include $2,114 and $2,260, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy and Sabine)	17,761	16,181
Long-term Risk Management Liabilities	174	131
Deferred Income Taxes	11,426	10,986
Regulatory Liabilities and Deferred Investment Tax Credits	3,850	3,892
Asset Retirement Obligations	2,038	1,951
Employee Benefits and Pension Obligations	509	630
Deferred Credits and Other Noncurrent Liabilities	1,088	1,071
TOTAL NONCURRENT LIABILITIES	36,846	34,842
TOTAL LIABILITIES	43,496	42,809
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2015	2014
Shares Authorized	600,000,000	600,000,000

Shares Issued	510,884,774	509,739,159		
(20,336,592 Shares were Held in Treasury as of June 30, 2015 and December 31, 2014)			3,321	3,313
Paid-in Capital			6,270	6,204
Retained Earnings			7,945	7,406
Accumulated Other Comprehensive Income (Loss)			(102)	(103)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			17,434	16,820
Noncontrolling Interests			8	4
TOTAL EQUITY			17,442	16,824
TOTAL LIABILITIES AND EQUITY			$60,938	$59,633

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 49.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2015 and 2014
(in millions)
(Unaudited)

	Six Months Ended June 30, 2015	2014
OPERATING ACTIVITIES		
Net Income	$1,062	$952
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,011	934
Deferred Income Taxes	453	410
Carrying Costs Income	(17)	(15)
Allowance for Equity Funds Used During Construction	(64)	(47)
Mark-to-Market of Risk Management Contracts	(41)	9
Amortization of Nuclear Fuel	66	79
Pension Contributions to Qualified Plan Trust	(93)	(71)
Property Taxes	102	92
Fuel Over/Under-Recovery, Net	22	(105)
Deferral of Ohio Capacity Costs, Net	(1)	(99)
Change in Other Noncurrent Assets	(91)	11
Change in Other Noncurrent Liabilities	12	132
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	12	(73)
Fuel, Materials and Supplies	149	207
Accounts Payable	(10)	(39)
Accrued Taxes, Net	(115)	(86)
Other Current Assets	22	(3)
Other Current Liabilities	(276)	(91)
Net Cash Flows from Operating Activities	2,203	2,197
INVESTING ACTIVITIES		
Construction Expenditures	(2,182)	(1,883)
Change in Other Temporary Investments, Net	30	(24)
Purchases of Investment Securities	(541)	(510)
Sales of Investment Securities	516	483
Acquisitions of Nuclear Fuel	(52)	(58)
Acquisitions of Assets/Businesses	(2)	(45)
Other Investing Activities	41	(31)
Net Cash Flows Used for Investing Activities	(2,190)	(2,068)
FINANCING ACTIVITIES		
Issuance of Common Stock, Net	56	29
Issuance of Long-term Debt	2,603	939
Change in Short-term Debt, Net	(241)	725
Retirement of Long-term Debt	(1,727)	(1,205)
Make Whole Premium on Extinguishment of Long-term Debt	(93)	—
Principal Payments for Capital Lease Obligations	(57)	(60)
Dividends Paid on Common Stock	(522)	(490)

Other Financing Activities	—	5
Net Cash Flows from (Used for) Financing Activities	19	(57)
Net Increase in Cash and Cash Equivalents	32	72
Cash and Cash Equivalents at Beginning of Period	163	118
Cash and Cash Equivalents at End of Period	$195	$190
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$431	$422
Net Cash Paid for Income Taxes	98	63
Noncash Acquisitions Under Capital Leases	76	33
Construction Expenditures Included in Current Liabilities as of June 30,	543	432
Construction Expenditures Included in Noncurrent Liabilities as of June 30,	66	—
Acquisition of Nuclear Fuel Included in Current Liabilities as of June 30,	—	42

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 49.

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 and six months ended June 30, 2015 is not necessarily indicative of results that may be expected for the year ending December 31, 2015. The condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2014 consolidated financial statements and notes thereto, which are included in our Form 10-K as filed with the SEC on February 20, 2015.

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, KPCo and WPCo 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 on January 1, 2014, 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 EPS is calculated by dividing net earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

The following tables present our basic and diluted EPS calculations included on our condensed statements of income:

	Three Months Ended June 30,			
	2015		2014	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$430		$390	
Weighted Average Number of Basic Shares Outstanding	490.2	$0.88	488.3	$0.80
Weighted Average Dilutive Effect of Restricted Stock Units	0.3	—	0.2	—
Weighted Average Number of Diluted Shares Outstanding	490.5	$0.88	488.5	$0.80

	Six Months Ended June 30,			
	2015		2014	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$1,059		$950	
Weighted Average Number of Basic Shares Outstanding	489.9	$2.16	488.1	$1.95
Weighted Average Dilutive Effect of Restricted Stock Units	0.3	—	0.3	—
Weighted Average Number of Diluted Shares Outstanding	490.2	$2.16	488.4	$1.95

There were no antidilutive shares outstanding as of June 30, 2015 and 2014.

2. NEW ACCOUNTING PRONOUNCEMENTS

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

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

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

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

ASU 2014-09 “Revenue from Contracts with Customers” (ASU 2014-09)

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

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

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

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

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

ASU 2015-03 “Simplifying the Presentation of Debt Issuance Costs” (ASU 2015-03)

In April 2015, the FASB issued ASU 2015-03 to simplify the presentation of debt issuance costs on the balance sheets. Under the new standard, debt issuance costs related to a recognized debt liability will be presented on the balance sheets as a direct deduction from the carrying amount of that debt liability, consistent with discounts. We include debt issuance costs in Deferred Charges and Other Noncurrent Assets on the condensed balance sheets. Debt issuance costs represent less than 1% of total long-term debt.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. We intend to early adopt ASU 2015-03 for the 2015 Form 10-K.

ASU 2015-05 “Customer's Accounting for Fees Paid in a Cloud Computing Arrangement” (ASU 2015-05)

In April 2015, the FASB issued ASU 2015-05 to provide guidance to customers about whether a cloud computing arrangement includes a software license. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. We are analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. We plan to adopt ASU 2015-05 effective January 1, 2016.

ASU 2015-11 “Simplifying the Measurement of Inventory” (ASU 2015-11)

In July 2015, the FASB issued ASU 2015-11 to simplify the guidance on the subsequent measurement of inventory, excluding inventory measured using last-in, first out or the retail inventory method. Under the new standard, inventory should be at the lower of cost and net realizable value. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016 with early adoption permitted. We are analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. We plan to adopt ASU 2015-11 effective January 1, 2017.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three and six months ended June 30, 2015 and 2014. 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 June 30, 2015

	Cash Flow Hedges				
	Commodity	Interest Rate and Foreign Currency	Securities Available for Sale	Pension and OPEB	Total
	(in millions)				
Balance in AOCI as of March 31, 2015	$(6)	$(18)	$9	$(88)	$(103)
Change in Fair Value Recognized in AOCI	(1)	—	(1)	—	(2)
Amounts Reclassified from AOCI	2	—	—	1	3
Net Current Period Other Comprehensive Income (Loss)	1	—	(1)	1	1
Balance in AOCI as of June 30, 2015	$(5)	$(18)	$8	$(87)	$(102)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 30, 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 March 31, 2014	$4	$(22)	$7	$(98)	$(109)
Change in Fair Value Recognized in AOCI	3	—	1	—	4
Amounts Reclassified from AOCI	(1)	1	—	1	1
Net Current Period Other Comprehensive Income	2	1	1	1	5
Balance in AOCI as of June 30, 2014	$6	$(21)	$8	$(97)	$(104)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2015

	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, 2014	$1	$(19)	$8	$(93)	$(103)
Change in Fair Value Recognized in AOCI	2	—	—	—	2
Amounts Reclassified from AOCI	(8)	1	—	1	(6)
Net Current Period Other Comprehensive Income (Loss)	(6)	1	—	1	(4)
	—	—	—	5	5

Pension and OPEB Adjustment Related to Mitchell Plant					
Balance in AOCI as of June 30, 2015	$(5)	$(18)	$8	$(87)	$(102)

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Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 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	(11)	—	1	—	(10)
Amounts Reclassified from AOCI	17	2	—	2	21
Net Current Period Other Comprehensive Income	6	2	1	2	11
Balance in AOCI as of June 30, 2014	$6	$(21)	$8	$(97)	$(104)

Reclassifications from Accumulated Other Comprehensive Income

The following tables provide details of reclassifications from AOCI for the three and six months ended June 30, 2015 and 2014. 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 June 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI Three Months Ended June 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in millions)	
Commodity:		
Generation & Marketing Revenues	$(4)	$—
Purchased Electricity for Resale	7	(2)
Subtotal – Commodity	3	(2)
Interest Rate and Foreign Currency:		
Interest Expense	—	2
Subtotal – Interest Rate and Foreign Currency	—	2
Reclassifications from AOCI, before Income Tax (Expense) Credit	3	—
Income Tax (Expense) Credit	1	—
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	2	—
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(5)	(5)
Amortization of Actuarial (Gains)/Losses	6	7
Reclassifications from AOCI, before Income Tax (Expense) Credit	1	2
Income Tax (Expense) Credit	—	1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1	1
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$3	$1

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Six Months Ended June 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI Six Months Ended June 30, 2015	2014
Gains and Losses on Cash Flow Hedges	(in millions)	
Commodity:		
Generation & Marketing Revenues	$(17)	$—
Purchased Electricity for Resale	6	29
Regulatory Assets/(Liabilities), Net (a)	—	(3)
Subtotal – Commodity	(11)	26
Interest Rate and Foreign Currency:		
Interest Expense	1	4
Subtotal – Interest Rate and Foreign Currency	1	4
Reclassifications from AOCI, before Income Tax (Expense) Credit	(10)	30
Income Tax (Expense) Credit	(3)	11
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(7)	19
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(10)	(10)
Amortization of Actuarial (Gains)/Losses	11	14
Reclassifications from AOCI, before Income Tax (Expense) Credit	1	4
Income Tax (Expense) Credit	—	2
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1	2
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$(6)	$21

(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 2014 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2014 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 2015 and updates the 2014 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	June 30, 2015 (in millions)	December 31, 2014
Regulatory Assets Currently Earning a Return		
Storm Related Costs	$20	$20
Material and Supplies Related to Retired Plants	19	—
West Virginia Vegetation Management Program	—	20
Regulatory Assets Currently Not Earning a Return		
Asset Retirement Obligation Costs Related to Retired Plants	51	—
Virginia Demand Response Program Costs	11	9
Ormet Special Rate Recovery Mechanism	10	10
Storm Related Costs	3	100
Carbon Capture and Storage Product Validation Facility	—	13
IGCC Pre-Construction Costs	—	11
Other Regulatory Assets Pending Final Regulatory Approval	23	43
Total Regulatory Assets Pending Final Regulatory Approval	$137	$226

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. 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.

In August 2012, the PUCO issued an order in a separate proceeding which implemented a PIRR to recover deferred fuel costs in rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. In November 2012, OPCo appealed that PUCO order to the Supreme Court of Ohio claiming a long-term debt rate modified the previously adjudicated 2009 - 2011 ESP order, which granted a weighted average cost of capital (WACC) rate. In November 2012, the IEU filed an appeal of the PUCO decision that included the argument that carrying costs should be reduced due to an accumulated deferred income tax credit. In June 2015, the Supreme Court of Ohio issued a decision that reversed the PUCO order on the carrying cost rate issue and dismissed the appeal filed by the IEU. In June 2015, the IEU filed a motion for reconsideration with the Supreme Court of Ohio related to the accumulated deferred income tax credit. If the Supreme Court of Ohio upholds its June 2015 order, it would remand the matter back to the PUCO for reinstatement of the WACC rate.

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

June 2012 – May 2015 ESP Including Capacity Charge

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

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

As part of the August 2012 ESP order, the PUCO established a non-bypassable RSR, effective September 2012. The RSR was collected from customers at $3.50/MWh through May 2014 and 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 July 2014, OPCo submitted a separate application to continue the RSR to collect the unrecovered portion of the deferred capacity costs at the rate of $4.00/MWh, until the balance of the capacity deferrals has been collected. In April 2015, the PUCO issued an order approving the application to continue the RSR, with modifications. The order included approval to continue the collection of deferred capacity costs at a rate of $4.00/MWh beginning June 1, 2015 for approximately 32 months, with carrying costs at a long-term cost of debt rate. Additionally, the order stated that an audit will be conducted of the May 31, 2015 capacity deferral balance, which was $444 million. In May 2015, the PUCO granted intervenors requests for rehearing. As of June 30, 2015, OPCo's incurred deferred capacity costs balance of $432 million, including debt carrying costs, was recorded in Regulatory Assets on the condensed balance sheet.

In 2013, the PUCO issued its Orders on Rehearing for the ESP which generally upheld its August 2012 order. The PUCO clarified that a final reconciliation of revenues and expenses would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket related to the competitive bid process (CBP). In 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO’s ESP order. Oral arguments at the Supreme Court of Ohio were held in May 2015.

In November 2013, the PUCO issued an order approving OPCo’s CBP with modifications. As ordered, in 2014, OPCo conducted multiple energy-only auctions for a total of 100% of the SSO load with delivery beginning April 2014 through May 2015. As provided for in the June 2015 - May 2018 ESP, for delivery starting in June 2015, OPCo now conducts energy and capacity auctions for its entire SSO load. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings.

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

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

June 2015 - May 2018 ESP

In December 2013, OPCo filed an application with the PUCO to approve an ESP that included proposed rate adjustments and the continuation and modification of certain existing riders, including the Distribution Investment Rider (DIR), effective June 2015 through May 2018. The proposal included a return on common equity of 10.65% on capital costs for certain riders. The proposal also included a purchased power agreement (PPA) rider that would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based PPA. The PPA would initially be based upon the OVEC contractual entitlement and could, upon further approval, be expanded to include other contracts involving other Ohio legacy generation assets. In October 2014, OPCo filed a separate application with the PUCO to propose a new extended PPA with AGR for 2,671 MW for inclusion in the PPA rider.

In February 2015, the PUCO issued an order approving OPCo's ESP application, subject to certain modifications, with a return on common equity of 10.2% on capital costs for certain riders. The order included (a) approval of the DIR with modified rate caps established by the PUCO, (b) authorization to establish a zero rate rider for OPCo's proposed PPA, (c) the option for OPCo to reapply in a future proceeding with a more detailed PPA proposal and (d) a directive to continue to pursue the transfer of the OVEC contractual entitlement to AGR or to otherwise divest of its interest in OVEC. In May 2015, on rehearing, the PUCO issued an order that increased the DIR rate caps and deferred ruling on all requests for rehearing related to the establishment of the PPA rider. In June 2015, OPCo and various intervenors filed applications for rehearing with the PUCO related to the May 2015 order on rehearing. In July 2015, the PUCO granted the requests for rehearing.

In May 2015, OPCo filed an amended PPA application between OPCo and AGR that (a) included OPCo's OVEC contractual entitlement, (b) addressed the PPA requirements set forth in the PUCO's February 2015 order, (c) updated supporting testimony to reflect a current analysis of the PPA proposal and (d) continued to include the 2,671 MW to be available for capacity, energy and ancillary services, produced by AGR over the lives of the respective generating units.

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

Significantly Excessive Earnings Test Filings

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

In June 2015, OPCo filed its 2014 SEET filing with the PUCO. Management believes its financial statements adequately address the impact of 2014 SEET requirements.

Corporate Separation

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

2009 Fuel Adjustment Clause Audit

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

In September 2014, the Supreme Court of Ohio upheld the PUCO order on appeal. A review of the coal reserve valuation by an outside consultant has not been initiated by the PUCO. 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.

2012 and 2013 Fuel Adjustment Clause Audits

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

Ormet

Ormet, a large aluminum company, had a contract to purchase power from OPCo through 2018. In 2013, Ormet filed for bankruptcy and subsequently shut down operations. In March 2014, the PUCO issued an order in OPCo’s Economic Development Rider (EDR) filing allowing OPCo to include $39 million of Ormet-related foregone revenues in the EDR effective April 2014. The order stated that if the stipulation agreement between OPCo and Ormet is subsequently adopted by the PUCO, OPCo could file an application to modify the EDR rate for the remainder of the period requesting recovery of the remaining $10 million of Ormet deferrals which, as of June 30, 2015, is recorded in Regulatory Assets on the condensed balance sheet. In April 2014, an intervenor filed testimony objecting to $5 million of the remaining foregone revenues. A hearing at the PUCO related to the stipulation agreement was held in May 2014.

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

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

SWEPCo Rate Matters

2012 Texas Base Rate Case

In 2012, SWEPCo filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In 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 June 30, 2015, the net book value of Welsh Plant, Unit 2 was $83 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 and in April 2014, this order became final. In May 2014, intervenors filed appeals of that order with the Texas District Court. In June 2014, SWEPCo intervened in those appeals and filed initial responses.

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

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

2014 Louisiana Formula Rate Filing

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

2015 Louisiana Formula Rate Filing

In April 2015, SWEPCo filed its formula rate plan for test year 2014 with the LPSC. The filing included a $14 million annual increase, which will be effective August 2015. This increase is subject to LPSC staff review and is subject to refund. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Welsh Plant, Units 1 and 3 – Environmental Projects

To comply with pending Federal EPA regulations, SWEPCo is currently constructing environmental control projects to meet mercury and air toxics standards for Welsh Plant, Units 1 and 3 at a cost of approximately $410 million, excluding AFUDC. Management currently estimates that the total environmental projects to be completed through 2020 for Welsh Plant, Units 1 and 3 will cost approximately $600 million, excluding AFUDC. As of June 30, 2015, SWEPCo has incurred costs of $256 million, including AFUDC, and has remaining contractual construction obligations of $89 million related to these projects. SWEPCo will seek recovery of these project costs from customers through filings at the state commissions and the FERC. As of June 30, 2015, the net book value of Welsh Plant, Units 1 and 3 was $484 million, before cost of removal, including materials and supplies inventory and CWIP. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

APCo and WPCo Rate Matters

2014 West Virginia Base Rate Case

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

In May 2015, the WVPSC issued an order on the base rate case. Upon implementation of the order in May 2015, and consistent with the WVPSC authorized total revenue, annual base rates were authorized to be increased by $99 million based upon a 9.75% return on common equity. The order included a delayed billing of $25 million of the annual base rate increase to residential customers until July 2016. The order provided for carrying charges based upon a WACC rate for the $25 million annual delayed billing through June 2016, and stated recovery would be addressed in the next ENEC case scheduled for 2016. Additionally, the order included approval of (a) an initial vegetation management rider of $45 million annually, (b) revised deprecation rates, including recovery of plants to be retired and (c) the recovery of $89 million in previously recorded regulatory assets, which will predominantly be recovered over five years.

In June 2015, the WVPSC staff and intervenors filed motions for reconsideration and clarification related to various issues including recovery of lost revenues and the allowed carrying charge rate related to the delayed residential revenues. In July 2015, the WVPSC issued an order that denied all motions for reconsideration.

2015 Virginia Regulatory Asset Proceeding

In January 2015, the Virginia SCC initiated a separate proceeding to address the proper treatment of APCo's authorized regulatory assets. As of June 30, 2015, APCo's authorized regulatory assets under review in this proceeding are estimated to be $12 million. In February and March 2015, briefs related to this proceeding were filed by various parties. If any of these costs, or any additional costs that may be subject to review, are not recoverable, it could reduce future net income and cash flows and impact financial condition.

New Virginia Legislation Affecting Biennial Reviews

In February 2015, amendments to Virginia law governing the regulation of investor-owned electric utilities were enacted. Under the amended Virginia law, APCo’s existing generation and distribution base rates are frozen until after the Virginia SCC rules on APCo’s next biennial review, which APCo will file in March 2020 for the 2018 and 2019 test years. These amendments also preclude the Virginia SCC from performing biennial reviews of APCo’s earnings for the years 2014 through 2017. APCo's financial statements adequately address the impact of these amendments. The new law provides that APCo will absorb its Virginia jurisdictional share of incremental generation and distribution costs incurred during 2014 through 2017 that are associated with severe weather events and/or natural disasters and costs associated with potential impairments related to new carbon emission guidelines issued by the Federal EPA.

PSO Rate Matters

2015 Oklahoma Base Rate Case

In July 2015, PSO filed a request with the OCC to increase annual revenues by $137 million to recover costs associated with its environmental compliance plan for the Federal EPA’s Regional Haze Rule and Mercury and Air Toxics Standards, and to recover investments and other costs that have increased since the last base rate case. The annual increase consists of (a) a base rate increase of $89 million, which includes $48 million in increased depreciation expense that reflects, among other things, recovery through June 2026 for Northeastern Plant, Units 3 and 4, (b) a rider or base rate increase of $44 million to recover costs for the environmental controls being installed on Northeastern Plant, Unit 3 and the Comanche Plant and (c) a request to include environmental consumable costs in the FAC, estimated to be $4 million annually. The rate increase includes a proposed return on equity of 10.5% and is proposed to be effective in January 2016, except for the $44 million for environmental investments, which is proposed to be effective in March 2016, after the Northeastern Plant, Unit 3 environmental controls go in service. The total estimated cost of the environmental controls to be installed at Northeastern Plant, Unit 3 and the Comanche Plant is $219 million, excluding AFUDC. As of June 30, 2015, PSO has incurred costs of $140 million related to these projects, including AFUDC.

In addition, the filing also notified the OCC that future incremental purchased capacity and energy costs of an estimated $35 million will be incurred related to the environmental compliance plan, due to the closure of Northeastern Plant, Unit 4 in April 2016, which would be recovered through the FAC. As of June 30, 2015, the net book value of Northeastern Plant, Unit 4 was $95 million, before cost of removal, including materials and supplies inventory and CWIP.

If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2014 Oklahoma Base Rate Case

In April 2015, the OCC issued an order that approved a non-unanimous stipulation agreement between PSO, the OCC staff and certain intervenors. The approved stipulation provides for no overall change to the transmission rider or to annual revenues, other than additional revenues through a separate rider related to advanced metering costs, and that the terms of the stipulation be effective November 2014. The advanced metering rider provides $24 million of revenues over 14 months beginning in November 2014 and increases to $27 million in 2016. The stipulation also included (a) new depreciation rates for advanced metering investments and existing meters, also effective November 2014, (b) a return on common equity of 9.85% to be used only in the formula to calculate AFUDC, factoring of customer receivables and for riders with an equity component and (c) recovery of regulatory assets for 2013 storms and regulatory case expenses. The advanced metering cost rider was implemented in November 2014.

I&M Rate Matters

Tanners Creek Plant

In October 2014, I&M filed an application with the IURC seeking approval of revised depreciation rates for Rockport Plant, Unit 1 and the Tanners Creek Plant. Upon retirement of the Tanners Creek Plant, I&M proposed that, for purposes of determining its depreciation rates, the net book value of the Tanners Creek Plant be recovered over the remaining life of the Rockport Plant. The new depreciation rates would result in a decrease in I&M's Indiana jurisdictional electric depreciation expense which I&M proposed to reduce customer rates through a credit rider. In May 2015, the IURC issued an order approving I&M's request for revised depreciation rates.

In May 2015, Tanners Creek Plant was retired. Upon retirement, $265 million was reclassified as Regulatory Assets on the condensed balance sheet related to the net book value of Tanners Creek Plant and is being amortized over 29 years. An additional $38 million was reclassified as Regulatory Assets on the condensed balance sheet for related asset retirement obligations and materials and supplies. These additional regulatory assets are currently not being amortized, pending regulatory approval.

Transmission, Distribution and Storage System Improvement Charge (TDSIC)

In October 2014, I&M filed petitions with the IURC for approval of a TDSIC Rider and approval of I&M’s seven-year TDSIC Plan, from 2015 through 2021, for eligible transmission, distribution and storage system improvements. The initial estimated cost of the capital improvements and associated operation and maintenance expenses included in the TDSIC Plan of $787 million, excluding AFUDC, would be updated annually. The TDSIC Plan included distribution investments specific to the Indiana jurisdiction. The TDSIC Rider would allow the periodic adjustment of I&M's rates to provide for timely recovery of 80% of approved TDSIC Plan costs. I&M would defer the remaining 20% of approved TDSIC Plan costs to be recovered in I&M's next general rate case. I&M did not seek a rate adjustment in this proceeding but sought approval of a TDSIC Rider rate adjustment mechanism for subsequent proceedings. In April 2015, I&M filed a notice with the IURC to seek approval of the proposed TDSIC Plan excluding $117 million of certain projects that were challenged in this proceeding. In May 2015, the IURC issued an order that denied I&M's TDSIC Plan and Rider. In May 2015, I&M filed a petition for reconsideration and/or rehearing with the IURC and in June 2015, filed a notice of appeal with the Indiana Court of Appeals.

KPCo Rate Matters

Plant Transfer

In October 2013, the KPSC issued an order that approved a modified settlement agreement which included the approval to transfer to KPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed. In December 2013, the Attorney General filed an appeal of the order with the Franklin County Circuit Court. In April 2015, the Franklin County Circuit Court issued an order that affirmed the KPSC's October 2013 order. In May 2015, the Attorney General filed an appeal of the April 2015 Franklin County Circuit Court order that had affirmed the KPSC's order.

Consistent with KPCo’s December 2012 plant transfer filing with the KPSC, Big Sandy Plant, Unit 2 was retired in May 2015. Upon retirement, $194 million was reclassified as Regulatory Assets on the condensed balance sheet related to the net book value of Big Sandy Plant, Unit 2 and the related asset retirement obligations, costs of removal and materials and supplies. These regulatory assets will be amortized over 25 years, effective July 2015.

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Kentucky Fuel Adjustment Clause Review

In August 2014, the KPSC issued an order initiating a review of KPCo's FAC from November 2013 through April 2014. In January 2015, the KPSC issued an order disallowing certain FAC costs during the period of January 2014 through May 2015 while KPCo owned and operated both Big Sandy Plant, Unit 2 and its one-half interest in the Mitchell Plant. As a result of this order, KPCo recorded a regulatory disallowance of $36 million in December 2014. In February 2015, KPCo filed an appeal of this order with the Franklin County Circuit Court. In April 2015, the Franklin County Circuit Court issued an order approving intervenors' requests to hold this case in abeyance until the KPSC issues a final order in KPCo’s two-year FAC review case for the period November 2012 through October 2014.

2014 Kentucky Base Rate Case

In December 2014, KPCo filed a request with the KPSC for a net increase in rates of $70 million, which consists of a $75 million increase in rider rates, offset by a $5 million decrease in annual base rates, to be effective July 2015 based upon a 10.62% return on common equity. The net increase reflects KPCo's ownership interest in the Mitchell Plant, riders to recover the Big Sandy Plant retirement and operational costs and the inclusion of an environmental compliance plan related to the Mitchell Plant FGD. Additionally, the filing included a request to recover deferred storm costs. In March 2015, intervenors filed testimony which recommended net increases in rates ranging from $20 million to $26 million. These increases consisted of proposed increases in rider rates ranging from $55 million to $63 million, offset by decreases in annual base rates ranging from $35 million to $37 million and based upon returns on common equity ranging from 8.65% to 8.75%. Intervenor recommendations included the recovery of deferred storm costs.

In April 2015, a non-unanimous stipulation agreement between KPCo and certain intervenors was filed with the KPSC. The parties to the stipulation recommended a net revenue increase of $45 million, which consisted of a $68 million increase in rider rates, offset by a $23 million decrease in annual base rates, to be effective July 2015. The proposed net increase reflects KPCo's ownership interest in the Mitchell Plant, riders to recover the Big Sandy Plant retirement and operational costs and the inclusion of an environmental compliance plan. Additionally, the agreement included (a) recovery of $12 million of deferred storm costs, (b) any difference between the actual off-system sales margins and the $15 million included in the proposed annual base rates to be shared with 75% to the customer and 25% to KPCo and (c) dismissal of the KPCo and the Kentucky Industrial Utility Customers appeals of the KPSC order in the KPCo fuel adjustment clause review for November 2012 through October 2014.

In June 2015, the KPSC issued an order that approved a modified stipulation agreement. The order approved a net revenue increase of $45 million, as proposed in the stipulation agreement, and contained modifications that included (a) approval to recover $2 million of IGCC and certain carbon capture study costs, both over 25 years, (b) no deferral of certain PJM costs and (c) denial of the recovery of certain potential purchased power costs through a rider. Once this order becomes final and non-appealable, KPCo will withdraw its appeal of the KPSC order in the KPCo fuel adjustment clause review. See "Kentucky Fuel Adjustment Clause Review" section above.

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 2014 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 of credit. As of June 30, 2015, the maximum future payments for letters of credit issued under the revolving credit facilities were $61 million with maturities ranging from October 2015 to June 2016.

We issue letters of credit under a $100 million uncommitted facility. As of June 30, 2015, the maximum future payments for letters of credit issued under the uncommitted facility were $100 million with a maturity of December 2015. An uncommitted facility gives the issuer of the facility the right to accept or decline each request we make under the facility.

We have $477 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $483 million. The letters of credit have maturities ranging from March 2016 to July 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 $58 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of June 30, 2015, SWEPCo has collected $65 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 $49 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 certain 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 June 30, 2015, 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 June 30, 2015, the maximum potential loss for these lease agreements was $30 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 assignments are accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $11 million and $12 million for I&M and SWEPCo, respectively, for the remaining railcars as of June 30, 2015.

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 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 $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. In 2014, I&M recorded an accrual for remediation at certain additional sites in Michigan. As a result of receiving approval of completed remediation work from the MDEQ in March 2015, I&M's accrual for all of these sites was reduced. As of June 30, 2015, I&M's accrual for all of these sites is approximately $9 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 sites or changes in the scope of remediation. 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 generation 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. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M. In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiffs’ claims. Several claims remain, including the claim for breach of the participation agreement and a claim alleging breach of an implied covenant of good faith and fair dealing. In June 2015, AEGCo and I&M filed a motion for partial judgment on the claims seeking dismissal of the breach of participation agreement claim as well as any claim for indemnification of costs associated with this case. In July 2015, the plaintiffs responded to the motion for partial judgment and simultaneously moved for partial summary judgment on their claims for breach of the lease and participation agreement. We will continue to defend against the remaining claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

Natural Gas Markets Lawsuits

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

Natural Gas Act and the order dismissing AEP from two of the cases on personal jurisdiction grounds and affirmed the decision denying leave to the plaintiffs to amend their complaints in two of the cases. Defendants in these cases, including AEP, filed a petition seeking further review with the U.S. Supreme Court on the preemption issue. AEP also subsequently filed a separate petition with the U.S. Supreme Court seeking review of the personal jurisdiction issue. In July 2014, the U.S. Supreme Court granted the defendants' previously filed petition for further review with the U.S. Supreme

Court on the preemption issue. Oral argument occurred in January 2015. In April 2015, the U.S. Supreme Court affirmed the judgment of the U.S. Court of Appeals for the Ninth Circuit on the preemption issue, holding that the plaintiffs' state antitrust claims were not preempted by the Natural Gas Act. The U.S. Supreme Court denied AEP's petition for review of the personal jurisdiction issue shortly thereafter. The cases have been remanded to the district court for further proceedings. We will continue to defend the cases. We believe the provision we have is adequate. We are unable to determine the amount of potential additional losses that are reasonably possible of occurring.

Wage and Hours Lawsuit

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

In March 2014, the federal court granted plaintiffs’ motion to conditionally certify the action as a class action. Notice was given to all potential class members and an additional 44 individuals opted in to the class, bringing the plaintiff class to 80 current and former employees. Two plaintiffs have since dismissed their claims without prejudice, leaving 78 plaintiffs. We will continue to defend the case. We are unable to determine a range of potential losses that are reasonably possible of occurring.

National Do Not Call Registry Lawsuit

In May 2014, AEP Energy was served with a complaint filed in the U.S. District Court for the Northern District of Illinois, alleging violations of the Telephone Consumer Protection Act (TCPA). The plaintiff alleges that he received telemarketing calls on behalf of AEP Energy despite having registered his telephone number on the National Do Not Call Registry. Plaintiff seeks to represent a class of persons who allegedly received such calls. Plaintiff seeks statutory damages under the TCPA on behalf of himself and the alleged class as well as injunctive relief. As a result of a mediation held in October 2014, the parties reached an agreement in principle, subject to final documentation and preliminary and final court approval. In April 2015, we filed a motion with the court for preliminary approval of the settlement. In June 2015, the court granted preliminary approval of the settlement. A final approval hearing related to this matter has been scheduled for September 2015. We will continue to defend the case. We believe the provision we have is adequate. We are unable to determine the amount of potential additional losses that are reasonably possible of occurring.

Gavin Landfill Litigation

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

6. BENEFIT PLANS

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

Components of Net Periodic Benefit Cost

The following tables provide the components of our net periodic benefit cost (credit) for the plans for the three and six months ended June 30, 2015 and 2014:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2015	2014	2015	2014
	(in millions)			
Service Cost	$24	$18	$3	$3
Interest Cost	52	56	14	17
Expected Return on Plan Assets	(68)	(65)	(27)	(28)
Amortization of Prior Service Credit	—	—	(17)	(17)
Amortization of Net Actuarial Loss	26	31	4	6
Net Periodic Benefit Cost (Credit)	$34	$40	$(23)	$(19)

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions)			
Service Cost	$47	$36	$6	$7
Interest Cost	103	111	28	34
Expected Return on Plan Assets	(137)	(131)	(55)	(56)
Amortization of Prior Service Cost (Credit)	1	1	(34)	(34)
Amortization of Net Actuarial Loss	53	62	9	11
Net Periodic Benefit Cost (Credit)	$67	$79	$(46)	$(38)

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.

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by OPCo, TCC and TNC.
- OPCo purchases energy and capacity to serve SSO customers and provides transmission and distribution services for all connected load.

AEP Transmission Holdco

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

Generation & Marketing

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

AEP River Operations

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

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

The tables below present our reportable segment income statement information for the three and six months ended June 30, 2015 and 2014 and reportable segment balance sheet information as of June 30, 2015 and December 31, 2014. 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 June 30, 2015								
Revenues from:								
External Customers	$2,159	$ 1,008	$ 25	$628	$ 115	$7	$ — (c)	$ 3,942
Other Operating Segments	24	53	74	173	13	17	(354)	—
Total Revenues	$2,183	$ 1,061	$ 99	$801	$ 128	$24	$ (354)	$ 3,942
Net Income (Loss)	$208	$ 78	$ 65	$82	$ 1	$(3)	$ —	$ 431

	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 June 30, 2014								
Revenues from:								
External Customers	$2,236 (b)	$ 1,064	$ 21	$573 (b)	$ 140	$10	$ — (c)	$ 4,044
Other Operating Segments	16 (b)	70	36	340 (b)	20	12	(494)	—
Total Revenues	$2,252	$ 1,134	$ 57	$913	$ 160	$22	$ (494)	$ 4,044
Net Income (Loss)	$155	$ 90	$ 47	$98	$ 3	$(2)	$ —	$ 391

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)							
Six Months Ended June 30, 2015								
Revenues from:								
External Customers	$4,646	$ 2,214	$ 47	$ 1,487	$ 243	$ 13	$ — (c)	$ 8,650
Other Operating Segments	42	117	110	484	24	37	(814)	—
Total Revenues	$4,688	$ 2,331	$ 157	$ 1,971	$ 267	$ 50	$ (814)	$ 8,650
Net Income (Loss)	$508	$ 175	$ 102	$ 269	$ 12	$ (4)	$ —	$ 1,062

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)							
Six Months Ended June 30, 2014								
Revenues from:								
External Customers	$4,785 (b)	$ 2,225	$ 33	$ 1,394 (b)	$ 286	$ 20	$ (51) (c)	$ 8,692
Other Operating Segments	53 (b)	124	52	770 (b)	39	28	(1,066)	—
Total Revenues	$4,838	$ 2,349	$ 85	$ 2,164	$ 325	$ 48	$ (1,117)	$ 8,692
Net Income (Loss)	$434	$ 187	$ 71	$ 261	$ 6	$ (7)	$ —	$ 952

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments		Consolidated
	(in millions)								
June 30, 2015									
Total Property, Plant and Equipment	$39,561	$ 13,506	$ 3,275	$7,456	$ 726	$357	$ (279	) (d)	$ 64,602
Accumulated Depreciation and Amortization	12,343	3,565	34	3,344	227	181	(105	) (d)	19,589
Total Property Plant and Equipment - Net	$27,218	$ 9,941	$ 3,241	$4,112	$ 499	$176	$ (174	) (d)	$ 45,013
Total Assets	$35,316	$ 14,351	$ 4,036	$5,668	$ 756	$21,599	$ (20,788	) (d) (e)	$ 60,938
Long-term Debt Due Within One Year:									
Affiliated	$—	$ —	$ —	$—	$ —	$—	$ —		$ —
Non-Affiliated	894	678	—	240	3	2	—		1,817
Long-term Debt:									
Affiliated	20	—	—	32	—	—	(52	)	—
Non-Affiliated	10,146	4,729	1,315	648	79	844	—		17,761
Total Long-term Debt	$11,060	$ 5,407	$ 1,315	$920	$ 82	$846	$ (52	)	$ 19,578

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments		Consolidated
	(in millions)								
December 31, 2014									
Total Property, Plant and Equipment	$39,402	$ 13,024	$ 2,714	$8,394	$ 700	$343	$ (272	) (d)	$ 64,305
Accumulated Depreciation	12,773	3,481	25	3,603	217	188	(99	) (d)	20,188

and Amortization									
Total Property Plant and Equipment - Net	$26,629	$ 9,543	$ 2,689	$4,791	$483	$155	$(173	)	(d)	$ 44,117
Total Assets	$33,750	$ 14,495	$ 3,575	$6,329	$749	$21,081	$(20,346	)	(d) (e)	$ 59,633
Long-term Debt Due Within One Year:									
Affiliated	$111	$ —	$ —	$86	$—	$—	$(197	)		$ —
Non-Affiliated	1,352	405	—	740	3	3	—			2,503
Long-term Debt:									
Affiliated	20	—	—	32	—	—	(52	)		—
Non-Affiliated	8,634	5,256	1,153	217	80	841	—			16,181
Total Long-term Debt	$10,117	$ 5,661	$ 1,153	$1,075	$83	$844	$(249	)		$ 18,684

(a) Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
(b) Includes the impact of corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013, as well as the impact of the termination of the Interconnection Agreement effective January 1, 2014.
(c) Reconciling Adjustments for External Customers primarily include eliminations as a result of corporate separation in Ohio.
(d) Includes eliminations due to an intercompany capital lease.
(e) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

We are exposed to certain market risks as a major power producer and participant in the wholesale electricity, natural gas, coal and emission allowance markets. 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 June 30, 2015 and December 31, 2014:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume June 30, 2015 (in millions)	December 31, 2014	Unit of Measure
Commodity:			
Power	440	334	MWhs
Coal	2	3	Tons
Natural Gas	73	106	MMBtus
Heating Oil and Gasoline	8	6	Gallons
Interest Rate	$129	$152	USD
Interest Rate and Foreign Currency	$564	$815	USD

Fair Value Hedging Strategies

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

Cash Flow Hedging Strategies

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

Our vehicle fleet and barge operations are exposed to gasoline and diesel fuel price volatility. We enter into financial heating oil and gasoline derivative contracts in order to mitigate price risk of our future fuel purchases. We discontinued cash flow hedge accounting for these derivative contracts effective March 31, 2014. In March 2014, these contracts were grouped as "Commodity" with other risk management activities. We do not hedge all fuel price risk.

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

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

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON OUR FINANCIAL STATEMENTS

The accounting guidance for “Derivatives and Hedging” requires recognition of all qualifying derivative instruments as either assets or liabilities on the 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 June 30, 2015 and December 31, 2014 condensed balance sheets, we netted $3 million and $4 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $27 million and $35 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 June 30, 2015 and December 31, 2014:

Fair Value of Derivative Instruments
June 30, 2015

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in millions)					
Current Risk Management Assets	$390	$22	$2	$414	$(242)	$ 172
Long-term Risk Management Assets	451	4	—	455	(92)	363
Total Assets	841	26	2	869	(334)	535
Current Risk Management Liabilities	311	18	1	330	(252)	78
Long-term Risk Management Liabilities	258	17	5	280	(106)	174
Total Liabilities	569	35	6	610	(358)	252
Total MTM Derivative Contract Net Assets (Liabilities)	$272	$(9)	$(4)	$259	$24	$ 283

Fair Value of Derivative Instruments
December 31, 2014

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

			Currency (a)		Position (b)	
	(in millions)					
Current Risk Management Assets	$392	$30	$3	$425	$(247)	$ 178
Long-term Risk Management Assets	367	3	—	370	(76)	294
Total Assets	759	33	3	795	(323)	472
Current Risk Management Liabilities	329	23	1	353	(261)	92
Long-term Risk Management Liabilities	208	8	9	225	(94)	131
Total Liabilities	537	31	10	578	(355)	223
Total MTM Derivative Contract Net Assets (Liabilities)	$222	$2	$(7)	$217	$32	$ 249

(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 and six months ended June 30, 2015 and 2014:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three and Six Months Ended June 30, 2015 and 2014

	Three Months Ended June 30,		Six Months Ended June 30,	
Location of Gain (Loss)	2015	2014	2015	2014
	(in millions)			
Vertically Integrated Utilities Revenues	$1	$4	$7	$22
Generation & Marketing Revenues	10	16	59	48
Other Operation Expense	—	—	(2)	—
Maintenance Expense	—	—	(1)	—
Purchased Electricity for Resale	—	—	4	—
Regulatory Assets (a)	4	—	—	—
Regulatory Liabilities (a)	49	29	53	118
Total Gain on Risk Management Contracts	$64	$49	$120	$188

(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. Certain derivatives that economically hedge future commodity risk are recorded in the same expense line item on the condensed statements of income as that of the associated risk. 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.

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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. The following table shows the results of our hedging gains (losses) during the three and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions)			
Gain on Fair Value Hedging Instruments	$1	$2	$6	$4
Loss on Fair Value Portion of Long-term Debt	(1)	(2)	(6)	(4)

During the three and six months ended June 30, 2015 and 2014, 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 and natural gas designated as cash flow hedges are included in Revenues 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 and six months ended June 30, 2015 and 2014, we designated power derivatives as cash flow hedges but did not designate 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. The impact of cash flow hedge accounting for these derivative contracts was immaterial and discontinued effective March 31, 2014.

We reclassify gains and losses on interest rate derivative hedges related to our debt financings from Accumulated Other Comprehensive Income (Loss) on 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 and six months ended June 30, 2015 and 2014, 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 and six months ended June 30, 2015 and 2014, we did not designate any foreign currency derivatives as cash flow hedges.

During the three and six months ended June 30, 2015 and 2014, 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 and six months ended

June 30, 2015 and 2014, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets as of June 30, 2015 and December 31, 2014 were:
Impact of Cash Flow Hedges on the Condensed Balance Sheet
June 30, 2015

	Commodity	Interest Rate and Foreign Currency	Total
	(in millions)		
Hedging Assets (a)	$10	$—	$10
Hedging Liabilities (a)	19	1	20
AOCI Loss Net of Tax	(5)	(18)	(23)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	4	(1)	3

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

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

(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 June 30, 2015, 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 90 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), we are obligated to post an additional amount of collateral for a limited number of derivative and non-derivative contracts primarily related to our competitive retail auction loads and guaranties for contractual obligations if our credit ratings decline below a specified rating threshold. The amount of collateral required fluctuates based on market prices and our total exposure. On an ongoing basis, our risk management organization assesses the appropriateness of these collateral triggering items in contracts. AEP and its subsidiaries have not experienced a downgrade below a specified rating threshold that would require the posting of additional collateral. The following table represents our exposure if our credit ratings were to decline below a specified rating threshold as of June 30, 2015 and December 31, 2014:

	June 30, 2015 (in millions)	December 31, 2014
Fair Value of Contracts with Credit Downgrade Triggers	$—	$—
Amount of Collateral AEP Subsidiaries Would Have been Required to Post for Derivative Contracts as well as Derivative and Non-Derivative Contracts Subject to the Same Master Netting Arrangement	—	—
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post Attributable to RTOs and ISOs	31	36
Amount of Collateral Attributable to Other Contracts (a)	304	281

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

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 June 30, 2015 and December 31, 2014:

	June 30, 2015 (in millions)	December 31, 2014
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$287	$235
Amount of Cash Collateral Posted	5	9
Additional Settlement Liability if Cross Default Provision is Triggered	225	178

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 reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer. The Competitive Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer and Chief Risk Officer in addition to Energy Supply's President and Vice President.

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

We utilize our trustee's external pricing service in our estimate of the fair value of the underlying investments held in the 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 June 30, 2015 and December 31, 2014 are summarized in the following table:

	June 30, 2015		December 31, 2014	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$19,578	$21,205	$18,684	$21,075

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:

	June 30, 2015			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash (a)	$249	$—	$—	$249
Fixed Income Securities – Mutual Funds	81	—	—	81
Equity Securities – Mutual Funds	13	13	—	26
Total Other Temporary Investments	$343	$13	$—	$356

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

(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 and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions)			
Proceeds from Investment Sales	$—	$—	$—	$—
Purchases of Investments	—	—	—	1
Gross Realized Gains on Investment Sales	—	—	—	—
Gross Realized Losses on Investment Sales	—	—	—	—

As of June 30, 2015 and December 31, 2014, we had no Other Temporary Investments with an unrealized loss position. As of June 30, 2015, 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 and six months ended June 30, 2015 and 2014, 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.

The following is a summary of nuclear trust fund investments as of June 30, 2015 and December 31, 2014:

	June 30, 2015			December 31, 2014		
	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$53	$—	$—	$20	$—	$—
Fixed Income Securities:						
United States Government	786	37	(3)	697	45	(5)
Corporate Debt	62	3	(1)	48	4	(1)
State and Local Government	70	1	—	208	1	—
Subtotal Fixed Income Securities	918	41	(4)	953	50	(6)
Equity Securities – Domestic	1,135	595	(78)	1,123	599	(79)
Spent Nuclear Fuel and Decommissioning Trusts	$2,106	$636	$(82)	$2,096	$649	$(85)

The following table provides the securities activity within the decommissioning and SNF trusts for the three and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions)			
Proceeds from Investment Sales	$288	$335	$516	$483
Purchases of Investments	295	345	541	509
Gross Realized Gains on Investment Sales	8	9	19	17
Gross Realized Losses on Investment Sales	6	8	10	9

The adjusted cost of fixed income securities was $877 million and $903 million as of June 30, 2015 and December 31, 2014, respectively. The adjusted cost of equity securities was $540 million and $524 million as of June 30, 2015 and December 31, 2014, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of June 30, 2015 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$141
1 year – 5 years	376
5 years – 10 years	186
After 10 years	215
Total	$918

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 June 30, 2015 and December 31, 2014. 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
June 30, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Cash and Cash Equivalents (a)	$17	$6	$—	$172	$195
Other Temporary Investments					
Restricted Cash (a)	205	7	—	37	249
Fixed Income Securities - Mutual Funds	81	—	—	—	81
Equity Securities – Mutual Funds (b)	26	—	—	—	26
Total Other Temporary Investments	312	7	—	37	356
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	23	524	269	(293)	523
Cash Flow Hedges:					
Commodity Hedges (c)	—	24	1	(15)	10
Fair Value Hedges	—	—	—	2	2
Total Risk Management Assets	23	548	270	(306)	535
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	42	—	—	11	53
Fixed Income Securities:					
United States Government	—	786	—	—	786
Corporate Debt	—	62	—	—	62
State and Local Government	—	70	—	—	70
Subtotal Fixed Income Securities	—	918	—	—	918
Equity Securities – Domestic (b)	1,135	—	—	—	1,135
Total Spent Nuclear Fuel and Decommissioning Trusts	1,177	918	—	11	2,106
Total Assets	$1,529	$1,479	$270	$(86)	$3,192
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$38	$444	$62	$(317)	$227
Cash Flow Hedges:					
Commodity Hedges (c)	—	29	5	(15)	19
Interest Rate/Foreign Currency Hedges	—	1	—	—	1

Fair Value Hedges	—	3	—	2	5
Total Risk Management Liabilities	$38	$477	$67	$(330)	$252

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

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

(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 June 30, 2015 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures ($5) million in 2015 and ($10) million in periods

2016-2018; Level 2 matures $16 million in 2015, $53 million in periods 2016-2018, $8 million in periods 2019-2020 and $3 million in periods 2021-2032; Level 3 matures $33 million in 2015, $59 million in periods 2016-2018, $22 million in periods 2019-2020 and $93 million in periods 2021-2032. Risk management commodity contracts are substantially comprised of power contracts.

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

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

There were no transfers between Level 1 and Level 2 during the three and six months ended June 30, 2015 and 2014.

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 June 30, 2015	Net Risk Management Assets (Liabilities)	
	(in millions)	
Balance as of March 31, 2015	$131	
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	2	
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	12	
Purchases, Issuances and Settlements (c)	(16	)
Transfers into Level 3 (d) (e)	42	
Transfers out of Level 3 (e) (f)	(2	)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	34	
Balance as of June 30, 2015	$203	

Three Months Ended June 30, 2014	Net Risk Management Assets (Liabilities)	
	(in millions)	
Balance as of March 31, 2014	$105	
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(14	)
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	6	
Purchases, Issuances and Settlements (c)	(2	)
Transfers into Level 3 (d) (e)	5	
Transfers out of Level 3 (e) (f)	(6	)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	38	
Balance as of June 30, 2014	$132	

Six Months Ended June 30, 2015	Net Risk Management Assets (Liabilities)	
	(in millions)	
Balance as of December 31, 2014	$151	
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	12	
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	51	
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(2	)
Purchases, Issuances and Settlements (c)	(54	)
Transfers into Level 3 (d) (e)	21	
Transfers out of Level 3 (e) (f)	(14	)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	38	
Balance as of June 30, 2015	$203	

Six Months Ended June 30, 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)	82
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(9)
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	14
Purchases, Issuances and Settlements (c)	(102)
Transfers into Level 3 (d) (e)	1
Transfers out of Level 3 (e) (f)	(7)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	36
Balance as of June 30, 2014	$132

(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 June 30, 2015 and December 31, 2014:

Significant Unobservable Inputs
June 30, 2015

	Fair Value Assets (in millions)	Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	High	Weighted Average
Energy Contracts	$232	$65	Discounted Cash Flow	Forward Market Price (a)	$13.50	$163.52	$37.79
				Counterparty Credit Risk (b)	328		
FTRs	38	2	Discounted Cash Flow	Forward Market Price (a)	(8.00)	9.87	1.37
Total	$270	$67					

Significant Unobservable Inputs
December 31, 2014

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

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

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs as of June 30, 2015:

Sensitivity of Fair Value Measurements
June 30, 2015

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

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

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

We, along with our subsidiaries, file income tax returns in various state, local and foreign jurisdictions. These taxing authorities routinely examine our tax returns. 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.

State Tax Legislation

House Bill 32 was passed by the state of Texas in June 2015 permanently reducing the Texas income/franchise tax rate from 0.95% to 0.75% effective January 1, 2016, applicable to reports originally due on or after the effective date. The Texas income/franchise tax rate had been scheduled to return to 1% in 2016. The enacted provision did not materially impact net income, cash flows or financial condition.

11. FINANCING ACTIVITIES

Long-term Debt

The following table details long-term debt outstanding as of June 30, 2015 and December 31, 2014:

Type of Debt	June 30, 2015	December 31, 2014
	(in millions)	
Senior Unsecured Notes	$13,628	$12,647
Pollution Control Bonds	1,963	1,963
Notes Payable	409	357
Securitization Bonds	2,200	2,380
Spent Nuclear Fuel Obligation (a)	266	266
Other Long-term Debt	1,144	1,101
Fair Value of Interest Rate Hedges	(3)	(6)
Unamortized Discount, Net	(29)	(24)
Total Long-term Debt Outstanding	19,578	18,684
Long-term Debt Due Within One Year	1,817	2,503
Long-term Debt	$17,761	$16,181

(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 June 30, 2015 and December 31, 2014, 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 six months of 2015 are shown in the tables below:

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
Issuances:		(in millions)	(%)	
APCo	Pollution Control Bonds	$86	1.90	2019
APCo	Senior Unsecured Notes	350	4.45	2045
APCo	Senior Unsecured Notes	300	3.40	2025
I&M	Notes Payable	111	Variable	2019
I&M	Other Long-term Debt	100	Variable	2018
PSO	Senior Unsecured Notes	125	3.17	2025
PSO	Senior Unsecured Notes	125	4.09	2045
SWEPCo	Pollution Control Bonds	54	1.60	2019
SWEPCo	Senior Unsecured Notes	400	3.90	2045
Non-Registrant:				
AEPTCo	Senior Unsecured Notes	60	4.01	2030
AEPTCo	Senior Unsecured Notes	50	3.66	2025
AEPTCo	Senior Unsecured Notes	40	3.76	2025
AGR	Other Long-term Debt	500	Variable	2017
KPCo	Other Long-term Debt	25	Variable	2018
Transource Missouri	Other Long-term Debt	13	Variable	2018
WPCo	Senior Unsecured Notes	113	3.36	2022
WPCo	Senior Unsecured Notes	122	3.70	2025

WPCo	Senior Unsecured Notes	50		4.20	2035
Total Issuances		$2,624	(a)		

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

Company	Type of Debt	Principal Amount Paid	Interest Rate	Due Date
Total Retirements and Principal Payments:		(in millions)	(%)	
APCo	Securitization Bonds	$ 11	2.008	2024
APCo	Senior Unsecured Notes	350	7.95	2020
APCo	Senior Unsecured Notes	300	3.40	2015
I&M	Other Long-term Debt	94	Variable	2015
I&M	Notes Payable	18	Variable	2016
I&M	Notes Payable	14	Variable	2017
I&M	Notes Payable	16	Variable	2019
I&M	Notes Payable	6	Variable	2019
I&M	Notes Payable	1	Variable	2016
I&M	Notes Payable	1	2.12	2016
OPCo	Pollution Control Bonds	86	3.125	2015
OPCo	Securitization Bonds	22	0.958	2018
SWEPCo	Notes Payable	2	4.58	2032
SWEPCo	Pollution Control Bonds	54	3.25	2015
SWEPCo	Senior Unsecured Notes	100	5.375	2015
Non-Registrant:				
AEGCo	Senior Unsecured Notes	4	6.33	2037
AEP Subsidiaries	Notes Payable	1	Variable	2017
AGR	Other Long-term Debt	500	Variable	2015
TCC	Securitization Bonds	78	5.09	2015
TCC	Securitization Bonds	42	6.25	2016
TCC	Securitization Bonds	27	0.88	2017
Total Retirements and Principal Payments		$ 1,727		

In July 2015, OPCo retired $23 million of Securitization Bonds.

In July 2015, SWEPCo retired $150 million of 4.9% Senior Unsecured Notes due in 2015.

In July 2015, TCC retired $94 million of Securitization Bonds.

As of June 30, 2015, trustees held on our behalf, $385 million of our reacquired Pollution Control Bonds.

Dividend Restrictions

Parent Restrictions

The holders of our common stock are entitled to receive the dividends declared by our Board of Directors provided funds are legally available for such dividends. Our income 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:

Type of Debt	June 30, 2015 Outstanding Amount (in millions)	Interest Rate (a)		December 31, 2014 Outstanding Amount (in millions)	Interest Rate (a)	
Securitized Debt for Receivables (b)	$708	0.27	%	$744	0.22	%
Commercial Paper	397	0.47	%	602	0.59	%
Total Short-term Debt	$1,105			$1,346		

(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 $750 million from bank conduits to purchase receivables. The agreement was increased in June 2014 from $700 million and expires in June 2017.

Accounts receivable information for AEP Credit is as follows:

	Three Months Ended June 30, 2015		2014		Six Months Ended June 30, 2015		2014	
	(dollars in millions)							
	0.27	%	0.22	%	0.27	%	0.23	%

Effective Interest Rates on Securitization of Accounts Receivable				
Net Uncollectible Accounts Receivable Written Off	$6	$7	$13	$14

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	June 30, 2015	December 31, 2014
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$977	$975
Total Principal Outstanding	708	744
Delinquent Securitized Accounts Receivable	50	44
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	19	13
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	363	335

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 any of these entities that was not previously contractually required. We hold a significant variable interest in DHLC and Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series).

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine’s only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo’s total billings from Sabine for the three months ended June 30, 2015 and 2014 were $41 million and $41 million, respectively, and for the six months ended June 30, 2015 and 2014 were $83 million and $80 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, which 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 DCC Fuel 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 June 30, 2015 and 2014 were $34 million and $32 million, respectively, and for the six months ended June 30, 2015 and 2014 were $57 million and $56 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. 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 Receivable – AEP Credit” section of Note 11.

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Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. Management has concluded that TCC is the primary beneficiary of Transition Funding because TCC has the power to direct the most significant activities of the VIE and TCC’s equity interest could potentially be significant. Therefore, TCC is required to consolidate Transition Funding. The securitized bonds totaled $1.6 billion and $1.8 billion as of June 30, 2015 and December 31, 2014, respectively. Transition Funding has securitized transition assets of $1.5 billion and $1.6 billion as of June 30, 2015 and December 31, 2014, 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 $210 million and $232 million as of June 30, 2015 and December 31, 2014, respectively. Ohio Phase-in-Recovery Funding has securitized assets of $98 million and $110 million as of June 30, 2015 and December 31, 2014, 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 $357 million and $368 million as of June 30, 2015 and December 31, 2014, respectively. Appalachian Consumer Rate Relief Funding has securitized assets of $339 million and $350 million as of June 30, 2015 and December 31, 2014, 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 tables 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 of EIS, management concluded that we are the primary beneficiary of the protected cell and are required to consolidate the protected cell of EIS. Our insurance premium expense to the protected cell for the three months ended June 30, 2015 and 2014 was $0.2 million and $1.4 million, respectively, and for the six months ended June 30, 2015 and 2014 was $14 million and $18 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. Therefore, AEP is required to consolidate Transource Energy. AEP's equity interest could potentially be significant. In January 2014, Transource Missouri (a wholly-owned subsidiary of Transource Energy) acquired transmission assets from the non-controlling owner and issued debt and received a capital contribution to fund the acquisition. The majority of Transource Energy's activity resulted from the asset acquisition, construction projects, debt issuance and capital contribution. AEP provided capital contributions to Transource Energy of $17 million and $23 million during the six months ended June 30, 2015 and the year ended December 31, 2014, respectively. AEP and the other owner of Transource Energy are required to ensure a specific equity level in Transource Missouri upon completion of projects or if a project is abandoned by the RTO. See the tables 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
June 30, 2015
(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	$58	$114	$986	$220		$33		$19		$155	$10
Net Property, Plant and Equipment	142	220	—	—		—		—		—	137
Other Noncurrent Assets	60	118	—	1,533	(a)	186	(b)	347	(c)	1	5
Total Assets	$260	$452	$986	$1,753		$219		$366		$156	$152
LIABILITIES AND EQUITY											
Current Liabilities	$28	$109	$886	$326		$47		$27		$43	$28
Noncurrent Liabilities	232	343	—	1,409		171		337		67	70

Equity	—	—	100	18	1	2	46	54
Total Liabilities and Equity	$260	$452	$986	$1,753	$219	$366	$156	$152

(a) Includes an intercompany item eliminated in consolidation of $72 million.
(b) Includes an intercompany item eliminated in consolidation of $87 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, 2014
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	AEP Credit	TCC Transition Funding		OPCo Ohio Phase-in-Recovery Funding		APCo Appalachian Consumer Rate Relief Funding		Protected Cell of EIS	Transource Energy
ASSETS											
Current Assets	$68	$97	$980	$239		$33		$18		$149	$2
Net Property, Plant and Equipment	145	158	—	—		—		—		—	98
Other Noncurrent Assets	52	80	—	1,654	(a)	210	(b)	358	(c)	2	4
Total Assets	$265	$335	$980	$1,893		$243		$376		$151	$104
LIABILITIES AND EQUITY											
Current Liabilities	$36	$86	$894	$322		$47		$27		$44	$21
Noncurrent Liabilities	228	249	—	1,553		195		347		62	55
Equity	1	—	86	18		1		2		45	28
Total Liabilities and Equity	$265	$335	$980	$1,893		$243		$376		$151	$104

(a) Includes an intercompany item eliminated in consolidation of $75 million.
(b) Includes an intercompany item eliminated in consolidation of $97 million.
(c) Includes an intercompany item eliminated in consolidation of $4 million.

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 June 30, 2015 and 2014 were $15 million and $6 million, respectively, and for the six months ended June 30, 2015 and 2014 were $29 million and $8 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:

	June 30, 2015		December 31, 2014	
	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	6	6	4	4
Advance Due to Parent	56	56	56	56
Guarantee of Debt	—	50	—	48

Total Investment in DHLC	$70	$120	$68	$116

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 and controlled by a subsidiary of FirstEnergy. Provisions exist within the PATH-WV agreement that make it 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, the transmission project that PATH was intended to develop, and removed it from the 2012 Regional Transmission Expansion Plan. In September 2012, the PATH Project companies submitted an application to the FERC requesting authority to recover prudently-incurred costs associated with the PATH Project. In November 2012, the FERC issued an order accepting the PATH Project's abandonment cost recovery application, subject to settlement procedures and hearing. The parties to the case have been unable to reach a settlement agreement and in March 2014, settlement judge procedures were terminated. Hearings at FERC were held in March and April 2015.

Our investment in PATH-WV was:

	June 30, 2015		December 31, 2014	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$19	$19	$19	$19
Retained Earnings	2	2	2	2
Total Investment in PATH-WV	$21	$21	$21	$21

As of June 30, 2015, our $21 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.

13. PROPERTY, PLANT AND EQUIPMENT

Asset Retirement Obligations (ARO)

We record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for our legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, closure and monitoring of underground carbon storage facilities at Mountaineer Plant, wind farms and certain coal mining facilities, as well as for nuclear decommissioning of our Cook Plant. We have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. We do not estimate the retirement for such easements because we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements, which is not expected.

We recorded an increase in our asset retirement obligations in the second quarter of 2015, primarily related to the final Coal Combustion Residual Rule, which was published in the Federal Register in April 2015. The Federal EPA now regulates the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and also FGD gypsum generated at some coal-fired plants. The Federal EPA regulates CCR as a non-hazardous solid waste and established minimum federal solid waste management standards. Noncash increases related to the CCR Rule are recorded as Property, Plant and Equipment. The following is a reconciliation of the aggregate carrying amount of ARO:

	Carrying Amount of ARO (in millions)
ARO as of December 31, 2014	$2,019
Accretion Expense	50
Liabilities Incurred	47
Liabilities Settled	(22)
Revisions in Cash Flow Estimates	48
ARO as of June 30, 2015	$2,142

As of June 30, 2015 and December 31, 2014, our ARO liability included $1.3 billion and $1.3 billion, respectively, for nuclear decommissioning of the Cook Plant. As of June 30, 2015 and December 31, 2014, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $1.8 billion and $1.8 billion, respectively, and are recorded in Spent Nuclear Fuel and Decommissioning Trusts on the condensed balance sheets.

14. DISPOSITION PLANT SEVERANCE

AEP retired several generation plants or units of plants during 2015. These plant closures resulted in involuntary severances. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

The disposition plant severance activity for the six months ended June 30, 2015 is described in the following table:

	Disposition Plant Severance Activity (in millions)	
Balance as of December 31, 2014	$29	
Incurred	3	
Settled	(11	)
Adjustments	—	
Balance as of June 30, 2015	$21	

We recorded a charge of $29 million to Other Operation expense in 2014 primarily related to employees at the disposition plants. These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the condensed statements of income. Of the cumulative expense, approximately 32% was within the Generation & Marketing segment and 68% was within the Vertically Integrated Utilities segment. The remaining liability is included in Other Current Liabilities on the condensed balance sheets. We incurred additional charges during the second quarter of 2015 as severance plans were finalized after the plants were retired. We do not expect additional severance costs to be incurred related to this initiative.

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

2014 West Virginia Base Rate Case

In June 2014, APCo filed a request with the WVPSC to increase annual base rates by $156 million to be effective in the second quarter of 2015. The filing included a request to increase generation depreciation rates primarily due to the increase in plant investment and changes in the expected service lives of various generating units. The filing also requested recovery of $77 million in regulatory assets over five years related to 2012 West Virginia storm costs, IGCC and other deferred costs. The filing also included a request to implement a rider of approximately $38 million annually to recover vegetation management costs, including a return on capital investment.

In May 2015, the WVPSC issued an order on the base rate case. Upon implementation of the order in May 2015, and consistent with the WVPSC authorized total revenue, annual base rates were authorized to be increased by $85 million. The order included a delayed billing of $22 million of the annual base rate increase to residential customers until July 2016. The order provided for carrying charges based upon a weighted average cost of capital rate for the $22 million annual delayed billing through June 2016, and stated recovery would be addressed in the next ENEC case scheduled for 2016. Additionally, the order included approval of (a) an initial vegetation management rider of $38 million annually, (b) revised deprecation rates, including recovery of plants to be retired and (c) the recovery of $77 million in previously recorded regulatory assets, which will predominantly be recovered over five years. See the "2014 West Virginia Base Rate Case" section of APCo Rate Matters in Note 4.

2015 Virginia Regulatory Asset Proceeding

In January 2015, the Virginia SCC initiated a separate proceeding to address the proper treatment of APCo's authorized regulatory assets. As of June 30, 2015, APCo's authorized regulatory assets under review in this proceeding are estimated to be $12 million. In February and March 2015, briefs related to this proceeding were filed by various parties. If any of these costs, or any additional costs that may be subject to review, are not recoverable, it could reduce future net income and cash flows and impact financial condition.

New Virginia Legislation Affecting Biennial Reviews

In February 2015, amendments to Virginia law governing the regulation of investor-owned electric utilities were enacted. Under the amended Virginia law, APCo's existing generation and distribution base rates are frozen until after the Virginia SCC rules on APCo's next biennial review, which APCo will file in March 2020 for the 2018 and 2019 test years. These amendments also preclude the Virginia SCC from performing biennial reviews of APCo's earnings for the years 2014 through 2017. APCo's financial statements adequately address the impact of these amendments. The new law provides that APCo will absorb its Virginia jurisdictional share of incremental generation and distribution costs incurred during 2014 through 2017 that are associated with severe weather events and/or natural disasters and costs associated with potential impairments related to new carbon emission guidelines issued by the Federal EPA.

West Virginia Inquiry into Plant Closures

Subsequent to APCo’s retirement of the Kanawha River Plant in May 2015, the WVPSC issued an order in July 2015 that requested APCo to maintain, for at least four years, any infrastructure installed at the Kanawha River Plant that would be used if the plant were to be converted to burn natural gas. The WVPSC stated that it would not be reasonable and prudent to completely demolish facilities that might be available in the future for conversion to natural gas before further consideration is given to the future of APCo’s coal fired generation. The order indicated that the WVPSC would consider prudently incurred operating fees related to Kanawha River Plant for recovery in a future case.

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 4 - Rate Matters and Note 6 - Commitments, Guarantees and Contingencies in the 2014 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 171. 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 249 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions of KWhs)			
Retail:				
Residential	2,238	2,266	6,440	6,628
Commercial	1,690	1,644	3,417	3,424
Industrial	2,567	2,573	5,027	5,065
Miscellaneous	212	209	428	431
Total Retail	6,707	6,692	15,312	15,548
Wholesale	788	873	1,654	1,944
Total KWhs	7,495	7,565	16,966	17,492

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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in degree days)			
Actual - Heating (a)	55	61	1,735	1,776
Normal - Heating (b)	91	92	1,412	1,403
Actual - Cooling (c)	471	402	471	402
Normal - Cooling (b)	360	360	366	367

(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.

Second Quarter of 2015 Compared to Second Quarter of 2014
Reconciliation of Second Quarter of 2014 to Second Quarter of 2015
Net Income
(in millions)

Second Quarter of 2014	$36	
Changes in Gross Margin:		
Retail Margins	25	
Transmission Revenues	2	
Total Change in Gross Margin	27	
Changes in Expenses and Other:		
Other Operation and Maintenance	9	
Depreciation and Amortization	(1	)
Other Income	3	
Interest Expense	4	
Total Change in Expenses and Other	15	
Income Tax Expense	(19	)
Second Quarter of 2015	$59	

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 $25 million primarily due to the following:
  - A $14 million increase primarily due to increases in rates in Virginia and West Virginia, offset by a decrease in formula rates. Of these changes, a $2 million decrease relates to riders/trackers which have corresponding decreases in other expense items below.
  - A $5 million increase in weather-related usage primarily due to a 17% increase in cooling degree days.
  - A $2 million decrease in generation-related PJM expenses net of recovery or offsets.

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

- Other Operation and Maintenance expenses decreased $9 million primarily due to the following:
  - A $5 million decrease in distribution maintenance expenses due to the storm expenses incurred in June 2014.
  - A $6 million decrease in plant maintenance expenses primarily at the Amos Plant due to a prior year outage.
  - A $4 million decrease in uncollectible accounts expense due to the establishment of a regulatory asset for recovery as allowed in the May 2015 West Virginia base case order.
  - A $3 million decrease in employee-related expenses.

  These decreases were partially offset by:
  - A $9 million increase in transmission operations primarily driven by PJM transmission expenses.
- Interest Expense decreased $4 million primarily due to the following:
  - A $1 million decrease due to 2014 amortization of loss on reacquired long-term debt.
  - A $1 million decrease due to reduced interest rates on long-term debt.
  - A $1 million increase in the debt component of AFUDC due to an increase in transmission projects.
  -

Income Tax Expense increased $19 million primarily due to an increase in pretax book income and the regulatory accounting treatment of state income taxes.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014
Reconciliation of Six Months Ended June 30, 2014 to Six Months Ended June 30, 2015
Net Income
(in millions)

Six Months Ended June 30, 2014	$138	
Changes in Gross Margin:		
Retail Margins	81	
Off-system Sales	(2	)
Transmission Revenues	2	
Total Change in Gross Margin	81	
Changes in Expenses and Other:		
Other Operation and Maintenance	4	
Depreciation and Amortization	4	
Carrying Costs Income	2	
Other Income	4	
Interest Expense	6	
Total Change in Expenses and Other	20	
Income Tax Expense	(38	)
Six Months Ended June 30, 2015	$201	

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 $81 million primarily due to the following:
- A $61 million increase primarily due to increases in rates in West Virginia and Virginia, including an adjustment affected by the amended Virginia Law that has an impact on biennial reviews. Of these increases, $9 million relate to riders/trackers which have corresponding increases in other expense items below.
- An $11 million decrease in generation-related PJM expenses due to the polar vortex in 2014 net of recovery or offsets.
- A $7 million decrease in expense due to the timing of fuel recovery in 2014.
- A $4 million increase in weather-related usage primarily due to a 17% increase in cooling degree days.

These increases were partially offset by:

- A $20 million decrease in normalized retail margin, primarily due to lower residential usage.

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

- Other Operation and Maintenance expenses decreased $4 million primarily due to the following:
- A $14 million decrease in plant maintenance expenses primarily at the Amos Plant due to a prior year outage.
- An $8 million decrease in employee-related expenses.
- A $5 million decrease in distribution maintenance expenses due to the storm expenses incurred in June 2014.
- A $4 million decrease in uncollectible accounts expense due to the establishment of a regulatory asset for recovery as allowed in the May 2015 West Virginia base case order.

These decreases were partially offset by:

- A $26 million increase in transmission operations primarily driven by PJM transmission expenses.
- Depreciation and Amortization expenses decreased $4 million primarily due to the following:

- A $6 million decrease due to prior year amortization of Virginia environmental deferrals, which ended in the first quarter of 2015.
- A $2 million decrease due to prior year amortization of West Virginia ENEC deferrals.

These decreases were partially offset by:

- A $3 million increase due to a higher depreciable base.
- Other Income increased $4 million primarily due to the increase in the equity component of AFUDC from increased transmission projects.
- Interest Expense decreased $6 million primarily due the following:
- A $2 million increase in the debt component of AFUDC from increased transmission projects.
- A $2 million decrease due to a decrease in long-term debt.
- Income Tax Expense increased $38 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 2014 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 249 for a discussion of accounting pronouncements.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
REVENUES				
Electric Generation, Transmission and Distribution	$645,452	$664,051	$1,499,631	$1,530,508
Sales to AEP Affiliates	33,836	28,070	76,351	72,984
Other Revenues	2,692	2,547	5,013	4,567
TOTAL REVENUES	681,980	694,668	1,580,995	1,608,059
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	183,485	202,903	406,732	433,640
Purchased Electricity for Resale	65,715	86,033	178,384	255,024
Purchased Electricity from AEP Affiliates	—	—	—	4,662
Other Operation	103,720	99,896	209,790	193,434
Maintenance	57,037	69,484	109,334	129,574
Depreciation and Amortization	96,297	95,650	196,440	200,236
Taxes Other Than Income Taxes	30,040	30,025	61,087	60,802
TOTAL EXPENSES	536,294	583,991	1,161,767	1,277,372
OPERATING INCOME	145,686	110,677	419,228	330,687
Other Income (Expense):				
Interest Income	449	389	838	790
Carrying Costs Income (Expense)	417	263	710	(1,612)
Allowance for Equity Funds Used During Construction	3,897	1,625	6,905	2,860
Interest Expense	(48,684)	(53,130)	(98,975)	(104,802)
INCOME BEFORE INCOME TAX EXPENSE	101,765	59,824	328,706	227,923
Income Tax Expense	42,713	23,577	127,861	89,825
NET INCOME	$59,052	$36,247	$200,845	$138,098

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net Income	$59,052	$36,247	$200,845	$138,098
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $1 and $90 for the Three Months Ended June 30, 2015 and 2014, Respectively, and $71 and $222 for the Six Months Ended June 30, 2015 and 2014, Respectively	2	166	131	412
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $247 and $180 for the Three Months Ended June 30, 2015 and 2014, Respectively, and $493 and $359 for the Six Months Ended June 30, 2015 and 2014, Respectively	(458)	(333)	(916)	(666)
TOTAL OTHER COMPREHENSIVE LOSS	(456)	(167)	(785)	(254)
TOTAL COMPREHENSIVE INCOME	$58,596	$36,080	$200,060	$137,844

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2013	$260,458	$1,809,562	$1,156,461	$2,951	$3,229,432
Common Stock Dividends			(40,000)		(40,000)
Net Income			138,098		138,098
Other Comprehensive Loss				(254)	(254)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2014	$260,458	$1,809,562	$1,254,559	$2,697	$3,327,276
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$260,458	$1,809,562	$1,291,876	$5,032	$3,366,928
Common Stock Dividends			(118,750)		(118,750)
Net Income			200,845		200,845
Other Comprehensive Loss				(785)	(785)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2015	$260,458	$1,809,562	$1,373,971	$4,247	$3,448,238

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2015 and December 31, 2014
(in thousands)
(Unaudited)

	June 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$2,523	$2,613
Restricted Cash for Securitized Funding	15,565	15,599
Advances to Affiliates	23,685	48,519
Accounts Receivable:		
Customers	126,488	114,711
Affiliated Companies	54,790	67,294
Accrued Unbilled Revenues	43,102	58,022
Miscellaneous	1,843	1,956
Allowance for Uncollectible Accounts	(3,032)	(2,364)
Total Accounts Receivable	223,191	239,619
Fuel	92,073	113,386
Materials and Supplies	129,521	131,285
Risk Management Assets	38,877	23,792
Deferred Income Tax Benefits	3,491	23,955
Regulatory Asset for Under-Recovered Fuel Costs	83,558	66,076
Prepayments and Other Current Assets	18,122	13,660
TOTAL CURRENT ASSETS	630,606	678,504
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,215,900	6,824,029
Transmission	2,249,454	2,228,029
Distribution	3,314,816	3,258,306
Other Property, Plant and Equipment	384,861	373,520
Construction Work in Progress	459,307	321,495
Total Property, Plant and Equipment	12,624,338	13,005,379
Accumulated Depreciation and Amortization	3,396,158	3,823,664
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	9,228,180	9,181,715
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,038,924	857,872
Securitized Assets	339,020	350,170
Long-term Risk Management Assets	3,002	4,891
Deferred Charges and Other Noncurrent Assets	154,587	159,230
TOTAL OTHER NONCURRENT ASSETS	1,535,533	1,372,163
TOTAL ASSETS	$11,394,319	$11,232,382

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2015 and December 31, 2014
(Unaudited)

	June 30, 2015	December 31, 2014
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$57,388	$—
Accounts Payable:		
General	170,980	166,821
Affiliated Companies	67,380	80,602
Long-term Debt Due Within One Year – Nonaffiliated	252,410	552,212
Long-term Debt Due Within One Year – Affiliated	—	86,000
Risk Management Liabilities	9,159	11,017
Customer Deposits	76,867	71,766
Accrued Taxes	99,682	109,482
Accrued Interest	41,675	52,141
Other Current Liabilities	142,079	145,017
TOTAL CURRENT LIABILITIES	917,620	1,275,058
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,714,237	3,342,062
Long-term Risk Management Liabilities	1,448	2,057
Deferred Income Taxes	2,384,223	2,288,842
Regulatory Liabilities and Deferred Investment Tax Credits	661,932	652,867
Asset Retirement Obligations	118,310	122,300
Employee Benefits and Pension Obligations	117,780	127,980
Deferred Credits and Other Noncurrent Liabilities	30,531	54,288
TOTAL NONCURRENT LIABILITIES	7,028,461	6,590,396
TOTAL LIABILITIES	7,946,081	7,865,454
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	1,373,971	1,291,876
Accumulated Other Comprehensive Income (Loss)	4,247	5,032
TOTAL COMMON SHAREHOLDER’S EQUITY	3,448,238	3,366,928
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$11,394,319	$11,232,382

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

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APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Six Months Ended June 30,	
	2015	2014
OPERATING ACTIVITIES		
Net Income	$200,845	$138,098
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	196,440	200,236
Deferred Income Taxes	122,498	90,236
Carrying Costs Income (Expense)	(710)	1,612
Allowance for Equity Funds Used During Construction	(6,905)	(2,860)
Mark-to-Market of Risk Management Contracts	(15,664)	(6,025)
Pension Contributions to Qualified Plan Trust	(9,981)	(8,963)
Fuel Over/Under-Recovery, Net	(15,297)	(108,943)
Change in Other Noncurrent Assets	(1,845)	2,861
Change in Other Noncurrent Liabilities	(10,436)	23,626
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	18,911	93,553
Fuel, Materials and Supplies	15,489	69,120
Accounts Payable	(20,590)	(46,812)
Accrued Taxes, Net	(11,450)	(9,690)
Other Current Assets	(2,212)	(2,294)
Other Current Liabilities	(21,028)	(10,469)
Net Cash Flows from Operating Activities	438,065	423,286
INVESTING ACTIVITIES		
Construction Expenditures	(293,100)	(224,879)
Change in Advances to Affiliates, Net	24,834	63,691
Other Investing Activities	7,012	(14,754)
Net Cash Flows Used for Investing Activities	(261,254)	(175,942)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	726,330	295,042
Change in Advances from Affiliates, Net	57,387	—
Retirement of Long-term Debt – Nonaffiliated	(661,055)	(500,016)
Retirement of Long-term Debt – Affiliated	(86,000)	—
Make Whole Premium on Extinguishment of Long-term Debt - Nonaffiliated	(92,658)	—
Principal Payments for Capital Lease Obligations	(2,571)	(2,904)
Dividends Paid on Common Stock	(118,750)	(40,000)
Other Financing Activities	416	1,002
Net Cash Flows Used for Financing Activities	(176,901)	(246,876)
Net Increase (Decrease) in Cash and Cash Equivalents	(90)	468
Cash and Cash Equivalents at Beginning of Period	2,613	2,745
Cash and Cash Equivalents at End of Period	$2,523	$3,213

SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$105,616	$96,564
Net Cash Paid for Income Taxes	5,226	1,280
Noncash Acquisitions Under Capital Leases	1,880	3,133
Construction Expenditures Included in Current Liabilities as of June 30,	81,624	50,052

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

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

Transmission, Distribution and Storage System Improvement Charge (TDSIC)

In October 2014, I&M filed petitions with the IURC for approval of a TDSIC Rider and TDSIC Plan for eligible transmission, distribution and storage system improvements. The initial estimated cost of the capital improvements and associated operation and maintenance expenses included in the TDSIC Plan of $787 million, excluding AFUDC, would be updated annually. The TDSIC Rider would allow the periodic adjustment of I&M's rates to provide for timely recovery of 80% of approved TDSIC Plan costs. I&M would defer the remaining 20% of approved TDSIC Plan costs to be recovered in I&M's next general rate case. In April 2015, I&M filed a notice with the IURC to seek approval of the proposed TDSIC Plan excluding $117 million of certain projects that were challenged in this proceeding. In May 2015, the IURC issued an order that denied I&M's TDSIC Plan and Rider. In May 2015, I&M filed a petition for reconsideration and/or rehearing with the IURC and in June 2015, filed a notice of appeal with the Indiana Court of Appeals. See the “Transmission, Distribution and Storage System Improvement Charge (TDSIC)” section of I&M Rate Matters in 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 4 - Rate Matters and Note 6 - Commitments, Guarantees and Contingencies in the 2014 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 171. 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 a motion to transfer this case to the U.S. District Court for the Southern District of Ohio. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M. In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiffs’ claims. Several claims remain, including the claim for breach of the participation agreement and a claim alleging breach of an implied covenant of good faith and fair dealing. In June 2015, AEGCo and I&M filed a motion for partial judgment on the claims seeking dismissal of the breach of participation agreement claim as well as any claim for indemnification of costs associated with this case. In

July 2015, the plaintiffs responded to the motion for partial judgment and simultaneously moved for partial summary judgment on their claims for breach of the lease and participation agreement. Management will continue to defend against the remaining 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 249 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions of KWhs)			
Retail:				
Residential	1,125	1,161	2,870	3,066
Commercial	1,193	1,196	2,402	2,417
Industrial	1,946	1,963	3,740	3,768
Miscellaneous	15	15	35	35
Total Retail	4,279	4,335	9,047	9,286
Wholesale	2,677	3,870	6,083	9,166
Total KWhs	6,956	8,205	15,130	18,452

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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in degree days)			
Actual - Heating (a)	172	244	2,931	3,216
Normal - Heating (b)	232	228	2,403	2,377
Actual - Cooling (c)	266	302	266	302
Normal - Cooling (b)	260	260	262	262

(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.

Second Quarter of 2015 Compared to Second Quarter of 2014
Reconciliation of Second Quarter of 2014 to Second Quarter of 2015
Net Income
(in millions)

Second Quarter of 2014	$27	
Changes in Gross Margin:		
Retail Margins	15	
FERC Municipals and Cooperatives	26	
Off-system Sales	(8	)
Transmission Revenues	2	
Other Revenues	(3	)
Total Change in Gross Margin	32	
Changes in Expenses and Other:		
Other Operation and Maintenance	3	
Taxes Other Than Income Taxes	(1	)
Interest Expense	1	
Total Change in Expenses and Other	3	
Income Tax Expense	(11	)
Second Quarter of 2015	$51	

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 $15 million primarily due to the following:
- A $10 million increase resulting from successful rate proceedings in the Indiana service territory.
- A $4 million increase due to decreased costs for power acquired under the Unit Power Agreement between AEGCo and I&M.
- A $2 million decrease in PJM related expenses.

These increases were partially offset by:

- A $4 million decrease in weather-related usage primarily due to a 30% decrease in heating degree days and a 12% decrease in cooling degree days.
- Margins from FERC Municipal and Cooperatives increased $26 million primarily due to the annual true-up adjustment of formula rates to actual costs.
- Margins from Off-system Sales decreased $8 million due to lower market prices and decreased sales volumes.
- Other Revenues decreased $3 million primarily due to a decrease in barging deliveries to the Rockport Plant by River Transportation Division (RTD). The decrease in RTD revenue was offset by a corresponding decrease in Other Operation and Maintenance expenses for barging discussed below.

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

- Other Operation and Maintenance expenses decreased $3 million primarily due to the following:
  - A $6 million decrease in administrative and general expenses.
  - A $5 million decrease in boiler plant maintenance expenses for Rockport Plant, Unit 1 and Tanners Creek units. Tanners Creek Plant was retired in May 2015.
  - A $3 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.

  These decreases were partially offset by:
  - A $12 million increase in nuclear expenses primarily due to $7 million related to Cook Plant, Unit 1 diesel generator repairs and $6 million for low pressure turbine inspections.
- Income Tax Expense increased $11 million primarily due to an increase in pretax book income and other book/tax differences which are accounted for on a flow-through basis, partially offset by the regulatory accounting treatment of state income taxes.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014
Reconciliation of Six Months Ended June 30, 2014 to Six Months Ended June 30, 2015
Net Income
(in millions)

Six Months Ended June 30, 2014	$114
Changes in Gross Margin:	
Retail Margins	31
FERC Municipals and Cooperatives	25
Off-system Sales	(51)
Transmission Revenues	3
Other Revenues	(8)
Total Change in Gross Margin	—
Changes in Expenses and Other:	
Other Operation and Maintenance	17
Depreciation and Amortization	(1)
Taxes Other Than Income Taxes	(3)
Interest Expense	4
Total Change in Expenses and Other	17
Income Tax Expense	(8)
Six Months Ended June 30, 2015	$123

The major components 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 $31 million primarily due to the following:
- A $27 million increase resulting from successful rate proceedings in the Indiana service territory.
- A $12 million decrease in PJM related expenses primarily related to the polar vortex in 2014.

These increases were partially offset by:
- A $7 million decrease in weather-related usage primarily due to a 12% decrease in cooling degree days and a 9% decrease in heating degree days.
- A $7 million decrease due to weather normalized usage.
- Margins from FERC Municipal and Cooperatives increased $25 million primarily due to the annual true-up adjustment of formula rates to actual costs.
- Margins from Off-system Sales decreased $51 million due to lower market prices and decreased sales volume.
- Other Revenues decreased $8 million primarily due to a decrease in barging deliveries to the Rockport Plant by RTD. The decrease in RTD revenue was offset by a corresponding decrease in Other Operation and Maintenance expenses for barging discussed below.

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

- Other Operation and Maintenance expenses decreased $17 million primarily due to the following:
  - A $9 million decrease in administrative and general expenses.
  - An $8 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.
  - A $6 million decrease due to the reduction of an environmental liability.

  These decreases were partially offset by:
  - A $7 million increase in nuclear expenses related to Cook Plant, Unit 1 diesel generator repairs.
- Interest Expense decreased $4 million primarily due to a lower interest rate on a remarketed pollution control bond and an early redemption of a senior unsecured note.
- Income Tax Expense increased $8 million primarily due to an increase in pretax book income and other book/tax differences which are accounted for on a flow-through basis, partially offset by the regulatory accounting treatment of state income taxes.

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 2014 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 249 for a discussion of accounting pronouncements.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
REVENUES				
Electric Generation, Transmission and Distribution	$515,027	$506,997	$1,081,277	$1,121,840
Sales to AEP Affiliates	6,504	1,068	6,957	3,352
Other Revenues – Affiliated	21,931	25,262	40,511	49,989
Other Revenues – Nonaffiliated	812	549	1,840	549
TOTAL REVENUES	544,274	533,876	1,130,585	1,175,730
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	74,041	113,700	173,925	270,343
Purchased Electricity for Resale	50,260	27,086	106,167	32,448
Purchased Electricity from AEP Affiliates	59,993	65,190	114,958	137,246
Other Operation	137,306	146,272	266,266	287,622
Maintenance	59,829	54,246	107,180	102,811
Depreciation and Amortization	49,540	49,446	100,947	99,477
Taxes Other Than Income Taxes	21,977	20,803	45,384	42,626
TOTAL EXPENSES	452,946	476,743	914,827	972,573
OPERATING INCOME	91,328	57,133	215,758	203,157
Other Income (Expense):				
Interest Income	3,578	1,729	5,326	2,778
Allowance for Equity Funds Used During Construction	2,907	4,804	6,950	8,768
Interest Expense	(22,968)	(23,705)	(45,745)	(49,338)
INCOME BEFORE INCOME TAX EXPENSE	74,845	39,961	182,289	165,365
Income Tax Expense	24,264	12,627	59,034	50,942
NET INCOME	$50,581	$27,334	$123,255	$114,423

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net Income	$50,581	$27,334	$123,255	$114,423
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $144 and $189 for the Three Months Ended June 30, 2015 and 2014, Respectively, and $288 and $418 for the Six Months Ended June 30, 2015 and 2014, Respectively	268	350	535	775
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $6 and $23 for the Three Months Ended June 30, 2015 and 2014, Respectively, and $12 and $46 for the Six Months Ended June 30, 2015 and 2014, Respectively	10	43	22	86
TOTAL OTHER COMPREHENSIVE INCOME	278	393	557	861
TOTAL COMPREHENSIVE INCOME	$50,859	$27,727	$123,812	$115,284

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2013	$56,584	$980,896	$900,182	$(15,509)	$1,922,153
Common Stock Dividends			(75,000)		(75,000)
Net Income			114,423		114,423
Other Comprehensive Income				861	861
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2014	$56,584	$980,896	$939,605	$(14,648)	$1,962,437
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$56,584	$980,896	$930,829	$(14,360)	$1,953,949
Common Stock Dividends			(60,000)		(60,000)
Net Income			123,255		123,255
Other Comprehensive Income				557	557
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2015	$56,584	$980,896	$994,084	$(13,803)	$2,017,761

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2015 and December 31, 2014
(in thousands)
(Unaudited)

	June 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$1,317	$1,020
Advances to Affiliates	13,504	13,481
Accounts Receivable:		
Customers	73,208	56,978
Affiliated Companies	59,434	72,582
Accrued Unbilled Revenues	220	503
Miscellaneous	1,561	1,625
Allowance for Uncollectible Accounts	(375)	(494)
Total Accounts Receivable	134,048	131,194
Fuel	23,884	54,623
Materials and Supplies	189,022	201,089
Risk Management Assets	16,514	22,328
Accrued Tax Benefits	28,457	24,788
Prepayments and Other Current Assets	28,566	27,968
TOTAL CURRENT ASSETS	435,312	476,491
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	3,931,860	3,741,831
Transmission	1,375,436	1,358,419
Distribution	1,735,290	1,698,409
Other Property, Plant and Equipment (June 30, 2015 and December 31, 2014 Amounts Include Coal Mining and Nuclear Fuel, December 31, 2014 Amount Includes 2015 Plant Retirement)	746,227	1,490,820
Construction Work in Progress	437,078	537,237
Total Property, Plant and Equipment	8,225,891	8,826,716
Accumulated Depreciation, Depletion and Amortization	3,049,243	3,410,341
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,176,648	5,416,375
OTHER NONCURRENT ASSETS		
Regulatory Assets	839,110	536,152
Spent Nuclear Fuel and Decommissioning Trusts	2,106,090	2,095,732
Long-term Risk Management Assets	2,026	3,317
Deferred Charges and Other Noncurrent Assets	127,922	137,209
TOTAL OTHER NONCURRENT ASSETS	3,075,148	2,772,410
TOTAL ASSETS	$8,687,108	$8,665,276

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2015 and December 31, 2014
(dollars in thousands)
(Unaudited)

	June 30, 2015	December 31, 2014
CURRENT LIABILITIES		
Advances from Affiliates	$140,658	$142,501
Accounts Payable:		
General	117,949	168,294
Affiliated Companies	75,328	76,010
Long-term Debt Due Within One Year – Nonaffiliated (June 30, 2015 and December 31, 2014 Amounts Include $109,242 and $85,657, Respectively, Related to DCC Fuel)	312,370	382,187
Risk Management Liabilities	4,493	5,223
Customer Deposits	35,224	35,206
Accrued Taxes	68,633	72,742
Accrued Interest	26,888	26,677
Obligations Under Capital Leases	42,186	42,050
Other Current Liabilities	112,701	150,566
TOTAL CURRENT LIABILITIES	936,430	1,101,456
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,776,543	1,645,210
Long-term Risk Management Liabilities	982	1,395
Deferred Income Taxes	1,332,635	1,264,167
Regulatory Liabilities and Deferred Investment Tax Credits	1,134,679	1,199,694
Asset Retirement Obligations	1,365,572	1,337,179
Deferred Credits and Other Noncurrent Liabilities	122,506	162,226
TOTAL NONCURRENT LIABILITIES	5,732,917	5,609,871
TOTAL LIABILITIES	6,669,347	6,711,327
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	994,084	930,829
Accumulated Other Comprehensive Income (Loss)	(13,803)	(14,360)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,017,761	1,953,949
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$8,687,108	$8,665,276

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
OPERATING ACTIVITIES		
Net Income	$123,255	$114,423
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	100,947	99,477
Deferred Income Taxes	48,011	17,499
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(11,605)	28,358
Allowance for Equity Funds Used During Construction	(6,950)	(8,768)
Mark-to-Market of Risk Management Contracts	5,962	(4,378)
Amortization of Nuclear Fuel	65,514	78,560
Fuel Over/Under-Recovery, Net	(15,089)	14,567
Change in Other Noncurrent Assets	31,547	(42,263)
Change in Other Noncurrent Liabilities	(25,024)	44,269
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(2,250)	45,666
Fuel, Materials and Supplies	31,084	4,668
Accounts Payable	6,764	(26,859)
Accrued Taxes, Net	(7,778)	17,381
Other Current Assets	5,214	9,815
Other Current Liabilities	(37,109)	(22,913)
Net Cash Flows from Operating Activities	312,493	369,502
INVESTING ACTIVITIES		
Construction Expenditures	(221,587)	(224,937)
Change in Advances to Affiliates, Net	(23)	42,357
Purchases of Investment Securities	(540,711)	(508,835)
Sales of Investment Securities	515,784	482,534
Acquisitions of Nuclear Fuel	(52,171)	(57,991)
Other Investing Activities	7,399	9,299
Net Cash Flows Used for Investing Activities	(291,309)	(257,573)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	210,702	99,419
Change in Advances from Affiliates, Net	(1,843)	47,353
Retirement of Long-term Debt – Nonaffiliated	(150,077)	(160,292)
Principal Payments for Capital Lease Obligations	(20,181)	(23,622)
Dividends Paid on Common Stock	(60,000)	(75,000)
Other Financing Activities	512	554
Net Cash Flows Used for Financing Activities	(20,887)	(111,588)
Net Increase in Cash and Cash Equivalents	297	341
Cash and Cash Equivalents at Beginning of Period	1,020	1,317

Cash and Cash Equivalents at End of Period	$1,317	$1,658
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$42,252	$42,779
Net Cash Paid for Income Taxes	17,066	13,206
Noncash Acquisitions Under Capital Leases	1,384	3,918
Construction Expenditures Included in Current Liabilities as of June 30,	53,118	59,759
Acquisition of Nuclear Fuel Included in Current Liabilities as of June 30,	30	42,076
Expected Reimbursement for Capital Cost of Spent Nuclear Fuel Dry Cask Storage	432	2,444

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

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

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

EXECUTIVE OVERVIEW

Regulatory Activity

Ohio Electric Security Plan Filings

2009 - 2011 ESP

In August 2012, the PUCO issued an order in a separate proceeding which implemented a PIRR to recover OPCo's deferred fuel costs in rates beginning September 2012. In June 2015, the Supreme Court of Ohio issued a decision that reversed, as requested by OPCo, the PUCO order on the carrying cost rate issue and dismissed the appeal filed by the IEU. In June 2015, the IEU filed a motion for reconsideration with the Supreme Court of Ohio related to the accumulated deferred income tax credit. If the Supreme Court of Ohio upholds its June 2015 order, it would remand the matter back to the PUCO for reinstatement of the weighted average cost of capital rate.

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 established base generation rates through May 2015. This ruling was generally upheld in PUCO rehearing orders in January and March 2013.

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

As part of the August 2012 ESP order, the PUCO established a non-bypassable RSR, effective September 2012. The RSR was collected from customers at $3.50/MWh through May 2014 and 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. In July 2014, OPCo submitted a separate application to continue the RSR to collect the unrecovered portion of the deferred capacity costs at the rate of $4.00/MWh, until the balance of the capacity deferrals has been collected. In April 2015, the PUCO issued an order approving the application to continue the RSR, with modifications. In May 2015, the PUCO granted intervenors requests for rehearing. As of June 30, 2015, OPCo's incurred deferred capacity costs balance was $432 million, including debt carrying costs.

In November 2013, the PUCO issued an order approving OPCo's competitive bid process with modifications. As ordered, in 2014, OPCo conducted multiple energy-only auctions for a total of 100% of the SSO load with delivery beginning April 2014 through May 2015. As provided for in the June 2015 - May 2018 ESP, for delivery starting in June 2015, OPCo now conducts energy and capacity auctions for its entire SSO load. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings.

In January 2014, the PUCO denied all rehearing requests and agreed to issue a supplemental request for an independent auditor in the 2012 - 2013 FAC proceeding to separately examine the recovery of the fixed fuel costs, including OVEC. In March 2014, the PUCO approved OPCo's request to implement riders related to the unbundling of the FAC. In October 2014, the independent auditor, selected by the PUCO, filed its report for the period August 2012 through May 2015 with the PUCO. If the PUCO ultimately concludes that a portion of the fixed fuel costs are also recovered through

OPCo's $188.88/MW day capacity charge, the independent auditor has recommended a methodology for calculating a refund of a portion of certain fixed fuel costs. The retail share of these fixed fuel costs is approximately $90 million annually. A hearing related to this matter has not been scheduled. Management believes that no over-recovery of costs has occurred and disagrees with the findings in the audit report.

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

June 2015 - May 2018 ESP

In December 2013, OPCo filed an application with the PUCO to approve an ESP that included proposed rate adjustments and the continuation and modification of certain existing riders effective June 2015 through May 2018. The proposal included a return on common equity of 10.65% on capital costs for certain riders. The proposal also included a purchased power agreement (PPA) rider that would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based PPA. In October 2014, OPCo filed a separate application with the PUCO to propose a new extended PPA with AGR for 2,671 MW for inclusion in the PPA rider.

In February 2015, the PUCO issued an order approving OPCo's ESP application, subject to certain modifications, with a return on common equity of 10.2% on capital costs for certain riders. The order included (a) approval of the Distribution Investment Rider (DIR) with modified rate caps established by the PUCO, (b) authorization to establish a zero rate rider for OPCo's proposed PPA, (c) the option for OPCo to reapply in a future proceeding with a more detailed PPA proposal and (d) a directive to continue to pursue the transfer of the OVEC contractual entitlement to AGR or to otherwise divest of its interest in OVEC. In May 2015, on rehearing, the PUCO issued an order that increased the DIR rate caps and deferred ruling on all requests for rehearing related to the establishment of the PPA rider. In June 2015, OPCo and various intervenors filed applications for rehearing with the PUCO related to the May 2015 order on rehearing. In July 2015, the PUCO granted the requests for rehearing.

In May 2015, OPCo filed an amended PPA application between OPCo and AGR that (a) included OPCo's OVEC contractual entitlement, (b) addressed the PPA requirements set forth in the PUCO's February 2015 order, (c) updated supporting testimony to reflect a current analysis of the PPA proposal and (d) continued to include the 2,671 MW to be available for capacity, energy and ancillary services, produced by AGR over the lives of the respective generating units.

If OPCo is ultimately not permitted to fully collect all components of its ESP rates, it could reduce future net income and cash flows and impact financial condition. See “Ohio Electric Security Plan Filings” section of OPCo Rate Matters in 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 4 - Rate Matters and Note 6 - Commitments, Guarantees and Contingencies in the 2014 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 171. 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 249 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions of KWhs)			
Retail:				
Residential	2,970	2,945	7,461	7,676
Commercial	3,550	3,545	7,145	7,124
Industrial	3,826	3,702	7,370	7,175
Miscellaneous	28	28	60	62
Total Retail (a)	10,374	10,220	22,036	22,037
Wholesale (b)	429	453	963	1,152
Total KWhs	10,803	10,673	22,999	23,189

(a) Represents energy delivered to distribution customers.
(b) Ohio's contractually obligated purchases of OVEC power sold into PJM.

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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in degree days)			
Actual - Heating (a)	137	130	2,575	2,539
Normal - Heating (b)	186	187	2,067	2,067
Actual - Cooling (c)	350	362	350	362
Normal - Cooling (b)	287	280	290	283

(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.

Second Quarter of 2015 Compared to Second Quarter of 2014
Reconciliation of Second Quarter of 2014 to Second Quarter of 2015
Net Income
(in millions)

Second Quarter of 2014	$57	
Changes in Gross Margin:		
Retail Margins	7	
Off-system Sales	(2	)
Transmission Revenues	(32	)
Other Revenues	5	
Total Change in Gross Margin	(22	)
Changes in Expenses and Other:		
Other Operation and Maintenance	16	
Depreciation and Amortization	(4	)
Taxes Other Than Income Taxes	(8	)
Carrying Costs Income	(2	)
Interest Expense	1	
Total Change in Expenses and Other	3	
Income Tax Expense	10	
Second Quarter of 2015	$48	

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 increased $7 million primarily due to the following:
  - A $14 million increase in transmission rider and PJM retail revenues primarily due to CRES transmission revenue collected through a non-bypassable retail transmission rider beginning in June 2015, which is partially offset by a corresponding decrease in Transmission Revenues below.
  - A $7 million increase in revenues associated with the Distribution Investment Rider.
  - A $4 million increase in industrial sales.

  These increases were partially offset by:
  - A $12 million decrease in revenues associated with the Storm Damage Recovery Rider which ended in April 2015. This decrease in Retail Margins is primarily offset by a decrease in Other Operation and Maintenance expenses below.
  - An $8 million decrease in the Energy Efficiency (EE), Peak Demand Reduction Cost Recovery Rider (PDR) revenues and associated deferrals. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
- Transmission Revenues decreased $32 million primarily due to the following:
  - A $12 million decrease in revenues related to a lower transmission formula rate true-up than in the prior year.
  - A $10 million decrease in NITS revenue due to OPCo assuming the responsibility for items determined to be cost-based transmission-related charges that were the responsibility of the CRES providers prior to June 2015, which is partially offset by a corresponding increase in Retail Margins above.

- A $7 million transmission regulatory loss provision in 2015.
- Other Revenues increased $5 million primarily due to increased pole attachment revenue.

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

- Other Operation and Maintenance expenses decreased $16 million primarily due to the following:
- A $12 million decrease due to the completion of the amortization of 2012 deferred storm expenses. This decrease was offset by a corresponding decrease in Retail Margins above.
- An $8 million decrease in EE and PDR costs and associated deferrals. This decrease was offset by a corresponding decrease in Retail Margins above.
- A $2 million decrease in employee-related expenses.

These decreases were partially offset by:

- A $6 million increase in recoverable PJM expenses.
- Depreciation and Amortization expenses increased $4 million primarily due to an increase in depreciable base of transmission and distribution assets.
- Taxes Other Than Income Taxes increased $8 million primarily due to an increase in property taxes due to additional investment in transmission and distribution assets and higher tax rates.
- Income Tax Expense decreased $10 million primarily due to a decrease in pretax book income and by the regulatory accounting treatment of state income taxes.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014
Reconciliation of Six Months Ended June 30, 2014 to Six Months Ended June 30, 2015
Net Income
(In Millions)

Six Months Ended June 30, 2014	$117	
Changes in Gross Margin:		
Retail Margins	27	
Off-system Sales	(2	)
Transmission Revenues	(34	)
Other Revenues	6	
Total Change in Gross Margin	(3	)
Changes in Expenses and Other:		
Other Operation and Maintenance	8	
Depreciation and Amortization	(5	)
Taxes Other Than Income Taxes	(10	)
Other Income	(2	)
Carrying Costs Income	(2	)
Interest Expense	2	
Total Change in Expenses and Other	(9	)
Income Tax Expense	8	
Six Months Ended June 30, 2015	$113	

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 increased $27 million primarily due to the following:
  - A $14 million increase in transmission rider and PJM retail revenues primarily due to CRES transmission revenue collected through a non-bypassable retail transmission rider beginning in June 2015, which is partially offset by a corresponding decrease in Transmission Revenues below.
  - A $15 million increase in revenues associated with the Distribution Investment Rider.
  - A $10 million increase in base rates due to the discontinuance of seasonal rates.
  - A $3 million increase in industrial sales.
  - A $3 million increase in revenues associated with the Storm Damage Recovery Rider which ended in April 2015. This increase in Retail Margins is primarily offset by an increase in Other Operation and Maintenance expenses below.

  These increases were partially offset by:
  - A $17 million decrease in the Energy Efficiency (EE), Peak Demand Reduction Cost Recovery Rider (PDR) revenues and associated deferrals. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
  - A $6 million decrease in revenues associated with the Universal Service Fund (USF) surcharge. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
- Transmission Revenues decreased $34 million primarily due to the following:
  - A $12 million decrease in revenues related to a lower transmission formula rate true-up than in the prior year.
  -

A $10 million decrease in NITS revenue due to OPCo assuming the responsibility for items determined to be cost-based transmission-related charges that were the responsibility of the CRES providers prior to June 2015, which is partially offset by a corresponding increase in Retail Margins above.

- A $7 million transmission regulatory loss provision in 2015.
- Other Revenues increased $6 million primarily due to increased pole attachment revenue.

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

- Other Operation and Maintenance expenses decreased $8 million primarily due to the following:
- A $17 million decrease in EE and PDR costs and associated deferrals. This decrease was offset by a corresponding decrease in Retail Margins above.
- A $6 million decrease in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This decrease was offset by a corresponding decrease in Retail Margins above.
- A $5 million decrease in employee-related expenses.

These decreases were partially offset by:

- A $14 million increase in recoverable PJM expenses.
- A $6 million increase due to PUCO ordered contributions to the Ohio Growth Fund.
- A $2 million increase due to the completion of the amortization of 2012 deferred storm expenses. This increase was offset by a corresponding increase in Retail Margins above.
- Depreciation and Amortization expenses increased $5 million primarily due to an increase in depreciable base of transmission and distribution assets.
- Taxes Other Than Income Taxes increased $10 million primarily due to an increase in property taxes due to additional investment in transmission and distribution assets and higher tax rates.
- Income Tax Expense decreased $8 million primarily due to a decrease in pretax book income and by the regulatory accounting treatment of state income taxes.

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 2014 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 249 for a discussion of accounting pronouncements.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
REVENUES				
Electricity, Transmission and Distribution	$670,250	$739,962	$1,544,467	$1,586,868
Sales to AEP Affiliates	33,158	44,443	75,264	76,421
Other Revenues	2,346	1,756	4,463	3,064
TOTAL REVENUES	705,754	786,161	1,624,194	1,666,353
EXPENSES				
Purchased Electricity for Resale	116,434	64,059	258,514	143,189
Purchased Electricity from AEP Affiliates	146,207	267,631	416,811	581,755
Amortization of Generation Deferrals	35,301	24,977	66,755	56,163
Other Operation	129,829	131,485	276,673	282,911
Maintenance	34,214	48,590	81,787	83,241
Depreciation and Amortization	55,640	51,485	114,852	110,184
Taxes Other Than Income Taxes	91,639	83,913	189,426	179,170
TOTAL EXPENSES	609,264	672,140	1,404,818	1,436,613
OPERATING INCOME	96,490	114,021	219,376	229,740
Other Income (Expense):				
Interest Income	1,250	2,899	3,163	6,173
Carrying Costs Income	5,153	6,874	11,613	13,988
Allowance for Equity Funds Used During Construction	2,343	1,342	4,787	3,068
Interest Expense	(31,271)	(32,759)	(63,720)	(65,766)
INCOME BEFORE INCOME TAX EXPENSE	73,965	92,377	175,219	187,203
Income Tax Expense	26,213	35,842	62,100	69,894
NET INCOME	$47,752	$56,535	$113,119	$117,309

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net Income	$47,752	$56,535	$113,119	$117,309
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $185 and $185 for the Three Months Ended June 30, 2015 and 2014, Respectively, and $370 and $426 for the Six Months Ended June 30, 2015 and 2014, Respectively	(343)	(343)	(686)	(791)
TOTAL COMPREHENSIVE INCOME	$47,409	$56,192	$112,433	$116,518

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2013	$321,201	$663,782	$633,203	$7,079	$1,625,265
Common Stock Dividends			(35,000)		(35,000)
Net Income			117,309		117,309
Other Comprehensive Loss				(791)	(791)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2014	$321,201	$663,782	$715,512	$6,288	$1,706,783
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$321,201	$838,782	$814,625	$5,602	$1,980,210
Common Stock Dividends			(87,500)		(87,500)
Net Income			113,119		113,119
Other Comprehensive Loss				(686)	(686)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2015	$321,201	$838,782	$840,244	$4,916	$2,005,143

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2015 and December 31, 2014
(in thousands)
(Unaudited)

	June 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$3,439	$2,870
Restricted Cash for Securitized Funding	28,699	28,687
Advances to Affiliates	187,812	312,473
Accounts Receivable:		
Customers	45,450	57,906
Affiliated Companies	91,434	79,822
Accrued Unbilled Revenues	803	35,755
Miscellaneous	720	927
Allowance for Uncollectible Accounts	(165)	(171)
Total Accounts Receivable	138,242	174,239
Notes Receivable Due Within One Year – Affiliated	—	86,000
Materials and Supplies	75,595	60,909
Risk Management Assets	—	7,242
Deferred Income Tax Benefits	44,336	49,306
Accrued Tax Benefits	5,699	6,100
Prepayments and Other Current Assets	8,705	8,997
TOTAL CURRENT ASSETS	492,527	736,823
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	2,159,276	2,104,613
Distribution	4,177,897	4,087,601
Other Property, Plant and Equipment	434,887	390,848
Construction Work in Progress	222,943	218,667
Total Property, Plant and Equipment	6,995,003	6,801,729
Accumulated Depreciation and Amortization	2,070,583	2,038,120
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,924,420	4,763,609
OTHER NONCURRENT ASSETS		
Notes Receivable – Affiliated	32,245	32,245
Regulatory Assets	1,237,933	1,318,939
Securitized Assets	97,849	109,999
Long-term Risk Management Assets	44,056	45,102
Deferred Charges and Other Noncurrent Assets	170,043	264,150
TOTAL OTHER NONCURRENT ASSETS	1,582,126	1,770,435
TOTAL ASSETS	$6,999,073	$7,270,867

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

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OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2015 and December 31, 2014
(dollars in thousands)
(Unaudited)

	June 30, 2015	December 31, 2014
CURRENT LIABILITIES		
Accounts Payable:		
General	$166,189	$145,328
Affiliated Companies	85,996	172,741
Long-term Debt Due Within One Year – Nonaffiliated (June 30, 2015 and December 31, 2014 Amounts Include $45,973 and $45,427, Respectively, Related to Ohio Phase-in-Recovery Funding)	396,045	131,497
Risk Management Liabilities	2,010	1,943
Customer Deposits	60,038	53,922
Accrued Taxes	320,688	420,772
Accrued Interest	33,242	34,279
Other Current Liabilities	128,328	179,093
TOTAL CURRENT LIABILITIES	1,192,536	1,139,575
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (June 30, 2015 and December 31, 2014 Amounts Include $164,295 and $187,041, Respectively, Related to Ohio Phase-in-Recovery Funding)	1,793,114	2,165,626
Long-term Risk Management Liabilities	4,573	3,013
Deferred Income Taxes	1,414,723	1,405,620
Regulatory Liabilities and Deferred Investment Tax Credits	530,224	514,691
Employee Benefits and Pension Obligations	28,498	36,662
Deferred Credits and Other Noncurrent Liabilities	30,262	25,470
TOTAL NONCURRENT LIABILITIES	3,801,394	4,151,082
TOTAL LIABILITIES	4,993,930	5,290,657
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	838,782	838,782
Retained Earnings	840,244	814,625
Accumulated Other Comprehensive Income (Loss)	4,916	5,602
TOTAL COMMON SHAREHOLDER’S EQUITY	2,005,143	1,980,210
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$6,999,073	$7,270,867

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

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OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Six Months Ended June 30,	
	2015	2014
OPERATING ACTIVITIES		
Net Income	$113,119	$117,309
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	114,852	110,184
Amortization of Generation Deferrals	66,755	56,163
Deferred Income Taxes	15,527	41,576
Carrying Costs Income	(11,613)	(13,988)
Allowance for Equity Funds Used During Construction	(4,787)	(3,068)
Mark-to-Market of Risk Management Contracts	9,916	(6,379)
Pension Contributions to Qualified Plan Trust	(7,671)	(6,547)
Property Taxes	96,279	100,522
Fuel Over/Under-Recovery, Net	(22,931)	28,671
Deferral of Ohio Capacity Costs, Net	(30,662)	(120,743)
Change in Other Noncurrent Assets	23,865	13,281
Change in Other Noncurrent Liabilities	22,543	46,213
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	38,230	(2,256)
Materials and Supplies	(14,687)	(4,205)
Accounts Payable	(68,105)	(70,228)
Customer Deposits	6,116	480
Accrued Taxes, Net	(99,683)	(138,584)
Other Current Assets	(787)	(560)
Other Current Liabilities	(30,230)	(24,522)
Net Cash Flows from Operating Activities	216,046	123,319
INVESTING ACTIVITIES		
Construction Expenditures	(236,048)	(213,974)
Change in Restricted Cash for Securitized Funding	(12)	(23,616)
Change in Advances to Affiliates, Net	124,661	339,070
Proceeds from Notes Receivable – Affiliated	86,000	139,450
Other Investing Activities	6,439	3,570
Net Cash Flows from (Used for) Investing Activities	(18,960)	244,500
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	—	34,723
Retirement of Long-term Debt – Nonaffiliated	(108,238)	(364,498)
Principal Payments for Capital Lease Obligations	(1,937)	(2,562)
Dividends Paid on Common Stock	(87,500)	(35,000)
Other Financing Activities	1,158	989
Net Cash Flows Used for Financing Activities	(196,517)	(366,348)
Net Increase in Cash and Cash Equivalents	569	1,471

Cash and Cash Equivalents at Beginning of Period	2,870	3,004
Cash and Cash Equivalents at End of Period	$3,439	$4,475
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$61,278	$69,127
Net Cash Paid for Income Taxes	20,500	10,863
Noncash Acquisitions Under Capital Leases	1,727	3,754
Construction Expenditures Included in Current Liabilities as of June 30,	42,222	40,878

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

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

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

EXECUTIVE OVERVIEW

Regulatory Activity

2015 Oklahoma Base Rate Case

In July 2015, PSO filed a request with the OCC to increase annual revenues by $137 million to recover costs associated with its environmental compliance plan and to recover investments and other costs that have increased since the last base rate case. The annual increase consists of (a) a base rate increase of $89 million, which includes $48 million in increased depreciation expense that reflects, among other things, recovery through June 2026 for Northeastern Plant, Units 3 and 4, (b) a rider or base rate increase of $44 million to recover costs for the environmental controls being installed on Northeastern Plant, Unit 3 and the Comanche Plant and (c) a request to include environmental consumable costs in the FAC, estimated to be $4 million annually. The rate increase includes a proposed return on equity of 10.5% and is proposed to be effective in January 2016, except for the $44 million for environmental investments, which is proposed to be effective in March 2016, after the Northeastern Plant, Unit 3 environmental controls go in service. In addition, the filing also notified the OCC that future incremental purchased capacity and energy costs of an estimated $35 million will be incurred related to the environmental compliance plan, due to the closure of Northeastern Plant, Unit 4 in April 2016, which would be recovered through the FAC. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the “2015 Oklahoma Base Rate Case” section of PSO Rate Matters in 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 4 - Rate Matters and Note 6 - Commitments, Guarantees and Contingencies in the 2014 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 171. 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 249 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions of KWhs)			
Retail:				
Residential	1,324	1,363	2,840	2,997
Commercial	1,329	1,311	2,460	2,450
Industrial	1,377	1,339	2,631	2,532
Miscellaneous	317	322	593	600
Total Retail	4,347	4,335	8,524	8,579
Wholesale	47	49	138	276
Total KWhs	4,394	4,384	8,662	8,855

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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in degree days)			
Actual - Heating (a)	10	48	1,176	1,417
Normal - Heating (b)	41	40	1,088	1,085
Actual - Cooling (c)	646	673	659	676
Normal - Cooling (b)	652	649	666	664

(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.

Second Quarter of 2015 Compared to Second Quarter of 2014
Reconciliation of Second Quarter of 2014 to Second Quarter of 2015
Net Income
(in millions)

Second Quarter of 2014	$22
Changes in Gross Margin:	
Retail Margins (a)	9
Total Change in Gross Margin	9
Changes in Expenses and Other:	
Other Operation and Maintenance	5
Depreciation and Amortization	(5)
Taxes Other Than Income Taxes	(3)
Allowance for Equity Funds Used During Construction	2
Total Change in Expenses and Other	(1)
Income Tax Expense	(3)
Second Quarter of 2015	$27

(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 $9 million primarily due to the revenue increases from rate riders. This increase in retail margins has corresponding increases to riders/trackers recognized in other expense items below.

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

- Other Operation and Maintenance expenses decreased $5 million primarily due to the following:
  - A $2 million decrease in distribution expenses primarily due to decreased vegetation management expenses.
  - A $2 million decrease in generation plant maintenance expenses.
  - A $2 million decrease in general and administrative expenses.
- Depreciation and Amortization expenses increased $5 million primarily due to the following:
  - A $2 million increase in amortization related to an advanced metering rider implemented in November 2014.
  - A $2 million increase due to a higher depreciable base.
- Taxes Other Than Income Taxes increased $3 million primarily due to a June 2014 property tax reduction resulting from a change in Oklahoma tax law.
- Income Tax Expense increased $3 million primarily due to an increase in pretax book income.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014
Reconciliation of Six Months Ended June 30, 2014 to Six Months Ended June 30, 2015
Net Income
(in millions)

Six Months Ended June 30, 2014	$31	
Changes in Gross Margin:		
Retail Margins (a)	19	
Transmission Revenues	1	
Total Change in Gross Margin	20	
Changes in Expenses and Other:		
Other Operation and Maintenance	7	
Depreciation and Amortization	(11	)
Allowance for Equity Funds Used During Construction	2	
Interest Expense	(2	)
Total Change in Expenses and Other	(4	)
Income Tax Expense	(6	)
Six Months Ended June 30, 2015	$41	

(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 $19 million primarily due to the following:
  - A $16 million increase primarily due to revenue increases from rate riders. This increase in retail margins has corresponding increases to riders/trackers recognized in other expense items below.
  - A $4 million increase due to increased industrial and commercial usage.

  These increases were partially offset by:
  - A $2 million decrease in weather-related usage primarily due to a 17% decrease in heating degree days.

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

- Other Operation and Maintenance expenses decreased $7 million primarily due to the following:
  - A $5 million decrease in generation plant maintenance expenses.
  - A $2 million decrease in distribution expenses primarily due to decreased vegetation management expenses.
- Depreciation and Amortization expenses increased $11 million primarily due to the following:
  - A $7 million increase in amortization related to an advanced metering rider implemented in November 2014.
  - A $3 million increase due to a higher depreciable base.
- 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 2014 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 249 for a discussion of accounting pronouncements.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
REVENUES				
Electric Generation, Transmission and Distribution	$317,611	$316,524	$622,284	$613,234
Sales to AEP Affiliates	1,164	854	2,443	5,451
Other Revenues	729	1,437	1,549	1,515
TOTAL REVENUES	319,504	318,815	626,276	620,200
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	52,981	41,612	138,580	107,549
Purchased Electricity for Resale	85,036	104,604	150,559	184,295
Purchased Electricity from AEP Affiliates	—	—	—	11,024
Other Operation	61,028	62,785	121,793	121,496
Maintenance	25,943	29,678	47,083	54,423
Depreciation and Amortization	29,782	24,607	59,316	48,589
Taxes Other Than Income Taxes	9,238	6,651	18,516	18,620
TOTAL EXPENSES	264,008	269,937	535,847	545,996
OPERATING INCOME	55,496	48,878	90,429	74,204
Other Income (Expense):				
Interest Income	92	4	128	1
Allowance for Equity Funds Used During Construction	2,283	590	3,610	2,021
Interest Expense	(14,852)	(13,779)	(29,422)	(27,096)
INCOME BEFORE INCOME TAX EXPENSE	43,019	35,693	64,745	49,130
Income Tax Expense	15,921	13,244	23,962	18,233
NET INCOME	$27,098	$22,449	$40,783	$30,897

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net Income	$27,098	$22,449	$40,783	$30,897
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $103 and $103 for the Three Months Ended June 30, 2015 and 2014, Respectively, and $205 and $235 for the Six Months Ended June 30, 2015 and 2014, Respectively	(190)	(190)	(380)	(436)
TOTAL COMPREHENSIVE INCOME	$26,908	$22,259	$40,403	$30,461

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2013	$157,230	$364,037	$415,076	$5,758	$942,101
Net Income			30,897		30,897
Other Comprehensive Loss				(436)	(436)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2014	$157,230	$364,037	$445,973	$5,322	$972,562
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$157,230	$364,037	$502,005	$4,943	$1,028,215
Net Income			40,783		40,783
Other Comprehensive Loss				(380)	(380)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2015	$157,230	$364,037	$542,788	$4,563	$1,068,618

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2015 and December 31, 2014
(in thousands)
(Unaudited)

	June 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$1,273	$1,352
Advances to Affiliates	64,212	—
Accounts Receivable:		
Customers	36,527	28,448
Affiliated Companies	22,410	22,114
Miscellaneous	3,549	6,026
Allowance for Uncollectible Accounts	(56)	(147)
Total Accounts Receivable	62,430	56,441
Fuel	14,584	16,436
Materials and Supplies	53,195	50,880
Risk Management Assets	1,731	—
Deferred Income Tax Benefits	5,182	—
Accrued Tax Benefits	27,226	24,369
Regulatory Asset for Under-Recovered Fuel Costs	—	35,699
Prepayments and Other Current Assets	4,802	6,524
TOTAL CURRENT ASSETS	234,635	191,701
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,292,305	1,264,724
Transmission	798,209	788,911
Distribution	2,162,261	2,080,221
Other Property, Plant and Equipment (Including Plant to be Retired)	432,397	421,568
Construction Work in Progress	244,404	204,753
Total Property, Plant and Equipment	4,929,576	4,760,177
Accumulated Depreciation and Amortization	1,363,314	1,319,554
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	3,566,262	3,440,623
OTHER NONCURRENT ASSETS		
Regulatory Assets	170,834	154,327
Long-term Risk Management Assets	29	—
Employee Benefits and Pension Assets	20,583	19,335
Deferred Charges and Other Noncurrent Assets	23,711	7,557
TOTAL OTHER NONCURRENT ASSETS	215,157	181,219
TOTAL ASSETS	$4,016,054	$3,813,543

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2015 and December 31, 2014
(Unaudited)

	June 30, 2015	December 31, 2014
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$—	$154,249
Accounts Payable:		
General	89,073	92,672
Affiliated Companies	55,424	51,744
Long-term Debt Due Within One Year – Nonaffiliated	434	427
Risk Management Liabilities	129	918
Customer Deposits	50,443	48,700
Accrued Taxes	36,266	20,887
Accrued Interest	16,142	12,699
Regulatory Liability for Over-Recovered Fuel Costs	15,894	—
Other Current Liabilities	43,867	58,878
TOTAL CURRENT LIABILITIES	307,672	441,174
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,290,561	1,040,609
Deferred Income Taxes	937,651	898,352
Regulatory Liabilities and Deferred Investment Tax Credits	335,164	334,479
Asset Retirement Obligations	41,980	37,030
Employee Benefits and Pension Obligations	15,423	20,095
Deferred Credits and Other Noncurrent Liabilities	18,985	13,589
TOTAL NONCURRENT LIABILITIES	2,639,764	2,344,154
TOTAL LIABILITIES	2,947,436	2,785,328
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	542,788	502,005
Accumulated Other Comprehensive Income (Loss)	4,563	4,943
TOTAL COMMON SHAREHOLDER’S EQUITY	1,068,618	1,028,215
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$4,016,054	$3,813,543

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Six Months Ended June 30,	
	2015	2014
OPERATING ACTIVITIES		
Net Income	$40,783	$30,897
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	59,316	48,589
Deferred Income Taxes	24,672	28,493
Allowance for Equity Funds Used During Construction	(3,610)	(2,021)
Mark-to-Market of Risk Management Contracts	(2,549)	578
Pension Contributions to Qualified Plan Trust	(5,795)	(4,439)
Property Taxes	(16,099)	(15,940)
Fuel Over/Under-Recovery, Net	51,593	(38,554)
Change in Other Noncurrent Assets	(14,048)	(10,411)
Change in Other Noncurrent Liabilities	4,492	(3,079)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(5,989)	(4,382)
Fuel, Materials and Supplies	(463)	3,330
Accounts Payable	5,482	959
Accrued Taxes, Net	12,522	(1,116)
Other Current Assets	644	(1,386)
Other Current Liabilities	(3,582)	9,888
Net Cash Flows from Operating Activities	147,369	41,406
INVESTING ACTIVITIES		
Construction Expenditures	(180,164)	(170,565)
Change in Advances to Affiliates, Net	(64,212)	—
Other Investing Activities	3,636	1,560
Net Cash Flows Used for Investing Activities	(240,740)	(169,005)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	248,785	74,975
Change in Advances from Affiliates, Net	(154,249)	88,028
Retirement of Long-term Debt – Nonaffiliated	(212)	(33,906)
Principal Payments for Capital Lease Obligations	(1,762)	(1,731)
Other Financing Activities	730	583
Net Cash Flows from Financing Activities	93,292	127,949
Net Increase (Decrease) in Cash and Cash Equivalents	(79)	350
Cash and Cash Equivalents at Beginning of Period	1,352	1,277
Cash and Cash Equivalents at End of Period	$1,273	$1,627
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$25,353	$26,684

Net Cash Paid for Income Taxes	4,228	2,463
Noncash Acquisitions Under Capital Leases	1,389	1,190
Construction Expenditures Included in Current Liabilities as of June 30,	30,881	40,150

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

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 Texas Base Rate Case

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

2012 Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share of the Turk Plant. In February 2013, a settlement was approved by the LPSC that increased SWEPCo's Louisiana total rates by approximately $2 million annually, effective March 2013. The March 2013 base rates are based upon a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover non-fuel Turk Plant costs and a full weighted-average cost of capital return on the prudently incurred Turk Plant investment in jurisdictional rate base, effective January 2013. In December 2014, the LPSC approved a settlement agreement related to the staff review of the cost of service. The settlement agreement reduced the requested revenue increase by $3 million, primarily due to the timing of both the allowed recovery of certain existing regulatory assets and the establishment of a regulatory asset for certain previously expensed costs. If the LPSC orders refunds based upon the pending prudence review of the Turk Plant investment, it could reduce future net income and cash flows and impact financial condition. See the “2012 Louisiana Formula Rate Filing” section of SWEPCo Rate Matters in 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, which was effective August 2014. SWEPCo also proposed to increase rates by an additional $15 million annually, effective January 2015, for a total annual increase of $20 million. This additional increase reflects the cost of incremental generation to be used to serve Louisiana customers in 2015 due to the expiration of a purchase power agreement attributable to Louisiana customers. In December 2014, the LPSC approved a partial settlement agreement that included the implementation of the $15 million annual increase in rates effective January 2015. These increases are subject to LPSC staff review and are subject to refund. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2015 Louisiana Formula Rate Filing

In April 2015, SWEPCo filed its formula rate plan for test year 2014 with the LPSC. The filing included a $14 million annual increase, which will be effective August 2015. This increase is subject to LPSC staff review and is subject to refund. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Welsh Plant, Units 1 and 3 - Environmental Projects

To comply with pending Federal EPA regulations, SWEPCo is currently constructing environmental control projects to meet mercury and air toxics standards for Welsh Plant, Units 1 and 3 at a cost of approximately $410 million, excluding AFUDC. Management currently estimates that the total environmental projects to be completed through 2020 for Welsh Plant, Units 1 and 3 will cost approximately $600 million, excluding AFUDC. As of June 30, 2015, SWEPCo has incurred costs of $256 million, including AFUDC, and has remaining contractual construction obligations of $89 million related to these projects. SWEPCo will seek recovery of these project costs from customers through filings at the state commissions and the FERC. See "Mercury and Other Hazardous Air Pollutants (HAPs) Regulation" and "Climate Change, CO_2 Regulation and Energy Policy" sections of “Environmental Issues” within “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries”. As of June 30, 2015, the net book value of Welsh Plant, Units 1 and 3 was $484 million, before cost of removal, including materials and supplies inventory and CWIP. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Merchant Portion of Turk Plant

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

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

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

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 4 - Rate Matters and Note 6 - Commitments, Guarantees and Contingencies in the 2014 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 171. 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 249 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions of KWhs)			
Retail:				
Residential	1,342	1,278	3,048	3,025
Commercial	1,557	1,446	2,923	2,839
Industrial	1,414	1,565	2,660	2,942
Miscellaneous	22	20	41	40
Total Retail	4,335	4,309	8,672	8,846
Wholesale	1,850	2,285	4,632	4,564
Total KWhs	6,185	6,594	13,304	13,410

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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in degree days)			
Actual - Heating (a)	8	45	920	1,039
Normal - Heating (b)	26	26	732	747
Actual - Cooling (c)	762	675	778	685
Normal - Cooling (b)	734	725	767	758

(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.

Second Quarter of 2015 Compared to Second Quarter of 2014
Reconciliation of Second Quarter of 2014 to Second Quarter of 2015
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Second Quarter of 2014	$32
Changes in Gross Margin:	
Retail Margins (a)	42
Off-system Sales	(4)
Transmission Revenues	2
Other Revenues	(2)
Total Change in Gross Margin	38
Changes in Expenses and Other:	
Other Operation and Maintenance	(3)
Depreciation and Amortization	(2)
Taxes Other Than Income Taxes	(1)
Allowance for Equity Funds Used During Construction	4
Total Change in Expenses and Other	(2)
Income Tax Expense	(10)
Second Quarter of 2015	$58

(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 $42 million primarily due to the following:
  - A $19 million increase in municipal and cooperative revenues primarily due to formula rate adjustments.
  - A $10 million increase primarily due to revenue increases from rate riders in Louisiana and Texas.
  - A $5 million increase primarily due to higher weather-normalized retail sales.
  - A $4 million increase in weather-related usage primarily due to a 13% increase in cooling degree days, partially offset by a decrease in heating degree days.
  - A $4 million increase primarily due to higher fuel cost recovery.
- Margins from Off-system Sales decreased $4 million primarily due to decreased sales volumes and lower market prices.

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

- Other Operation and Maintenance expenses increased $3 million primarily due to the following:
  - A $3 million increase in distribution expenses primarily due to increased vegetation management expenses.
  - A $3 million increase in transmission expenses primarily due to increased SPP transmission services.
  - A $2 million increase in generation plant expenses.

  These increases were partially offset by:
  - A $2 million decrease in general and administrative expenses.
  - A $2 million decrease in energy efficiency program expenses.

- Allowance for Equity Funds Used During Construction increased $4 million primarily due to increased environmental and transmission projects.
- Income Tax Expense increased $10 million primarily due to an increase in pretax book income, partially offset by other book/tax differences which are accounted for on a flow-through basis.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014
Reconciliation of Six Months Ended June 30, 2014 to Six Months Ended June 30, 2015
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Six Months Ended June 30, 2014	$54	
Changes in Gross Margin:		
Retail Margins (a)	68	
Off-system Sales	(6	)
Transmission Revenues	1	
Other Revenues	(2	)
Total Change in Gross Margin	61	
Changes in Expenses and Other:		
Other Operation and Maintenance	3	
Depreciation and Amortization	(3	)
Taxes Other Than Income Taxes	(2	)
Interest Income	1	
Allowance For Equity Funds Used During Construction	7	
Interest Expense	2	
Total Change in Expenses and Other	8	
Income Tax Expense	(19	)
Six Months Ended June 30, 2015	$104	

(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 $68 million primarily due to the following:
  - A $22 million increase in municipal and cooperative revenues primarily due to formula rate adjustments.
  - A $21 million increase primarily due to revenue increases from rate riders in Louisiana and Texas.
  - A $19 million increase primarily due to higher fuel cost recovery.
  - A $6 million increase in weather-related usage primarily due to a 14% increase in cooling degree days, partially offset by a decrease in heating degree days.
- Margins from Off-system Sales decreased $6 million primarily due to lower market prices.

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

- Other Operation and Maintenance expenses decreased $3 million primarily due to the following:
  - A $4 million decrease in general and administrative expenses.
  - A $4 million decrease in generation plant expenses.
  - A $3 million decrease in energy efficiency program and customer collection-related expenses.

  These decreases were partially offset by:
  - A $5 million increase in transmission expenses primarily due to increased SPP transmission services.
  - A $4 million increase in distribution expenses primarily due to increased vegetation management expenses.

- Depreciation and Amortization expenses increased $3 million primarily due to a higher depreciable base.
- Allowance for Equity Funds Used During Construction increased $7 million primarily due to increased environmental and transmission projects.
- Income Tax Expense increased $19 million primarily due to an increase in pretax book income, partially offset by other book/tax differences which are accounted for on a flow-through basis.

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 2014 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 249 for a discussion of accounting pronouncements.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
REVENUES				
Electric Generation, Transmission and Distribution	$433,187	$444,652	$861,722	$871,279
Sales to AEP Affiliates	4,486	3,947	7,156	17,545
Other Revenues	364	684	868	1,049
TOTAL REVENUES	438,037	449,283	869,746	889,873
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	125,365	161,116	283,097	306,703
Purchased Electricity for Resale	27,188	40,255	47,202	101,420
Purchased Electricity from AEP Affiliates	—	—	—	3,766
Other Operation	67,899	69,304	133,444	137,841
Maintenance	38,237	33,668	65,651	64,079
Depreciation and Amortization	47,964	45,864	94,918	91,525
Taxes Other Than Income Taxes	21,316	20,289	43,048	41,026
TOTAL EXPENSES	327,969	370,496	667,360	746,360
OPERATING INCOME	110,068	78,787	202,386	143,513
Other Income (Expense):				
Interest Income	1,184	206	1,164	92
Allowance for Equity Funds Used During Construction	5,882	2,197	11,111	4,278
Interest Expense	(31,945)	(31,738)	(62,160)	(63,614)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	85,189	49,452	152,501	84,269
Income Tax Expense	26,887	17,045	48,059	29,210
Equity Earnings of Unconsolidated Subsidiary	1,124	416	1,721	726
NET INCOME	59,426	32,823	106,163	55,785
Net Income Attributable to Noncontrolling Interest	956	1,126	1,989	2,228
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$58,470	$31,697	$104,174	$53,557

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net Income	$59,426	$32,823	$106,163	$55,785
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $306 and $306 for the Three Months Ended June 30, 2015 and 2014, Respectively, and $611 and $576 for the Six Months Ended June 30, 2015 and 2014, Respectively	567	567	1,134	1,069
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $129 and $127 for the Three Months Ended June 30, 2015 and 2014, Respectively, and $258 and $253 for the Six Months Ended June 30, 2015 and 2014, Respectively	(239)	(235)	(479)	(469)
TOTAL OTHER COMPREHENSIVE INCOME	328	332	655	600
TOTAL COMPREHENSIVE INCOME	59,754	33,155	106,818	56,385
Total Comprehensive Income Attributable to Noncontrolling Interest	956	1,126	1,989	2,228
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$58,798	$32,029	$104,829	$54,157

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Six Months Ended June 30, 2015 and 2014
(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, 2013	$135,660	$674,606	$1,253,617	$(8,444)	$478	$2,055,917
Common Stock Dividends			(50,000)			(50,000)
Common Stock Dividends – Nonaffiliated					(2,309)	(2,309)
Net Income			53,557		2,228	55,785
Other Comprehensive Income				600		600
TOTAL EQUITY - JUNE 30, 2014	$135,660	$674,606	$1,257,174	$(7,844)	$397	$2,059,993
TOTAL EQUITY - DECEMBER 31, 2014	$135,660	$674,606	$1,293,986	$(7,466)	$415	$2,097,201
Common Stock Dividends			(60,000)			(60,000)
Common Stock Dividends – Nonaffiliated					(2,107)	(2,107)
Net Income			104,174		1,989	106,163
Other Comprehensive Income				655		655
TOTAL EQUITY - JUNE 30, 2015	$135,660	$674,606	$1,338,160	$(6,811)	$297	$2,141,912

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2015 and December 31, 2014
(in thousands)
(Unaudited)

	June 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents (June 30, 2015 and December 31, 2014 Amounts Include $6,436 and $12,695, Respectively, Related to Sabine)	$ 8,017	$ 14,356
Advances to Affiliates	179,709	41,033
Accounts Receivable:		
Customers	72,169	46,738
Affiliated Companies	24,986	37,114
Miscellaneous	26,675	25,625
Allowance for Uncollectible Accounts	(39)	(516)
Total Accounts Receivable	123,791	108,961
Fuel (June 30, 2015 and December 31, 2014 Amounts Include $30,020 and $38,920, Respectively, Related to Sabine)	105,171	116,955
Materials and Supplies	73,297	73,666
Risk Management Assets	2,077	31
Deferred Income Tax Benefits	9,610	9,041
Accrued Tax Benefits	9,423	15,408
Regulatory Asset for Under-Recovered Fuel Costs	19,118	24,024
Prepayments and Other Current Assets	23,912	25,779
TOTAL CURRENT ASSETS	554,125	429,254
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	3,927,856	3,864,543
Transmission	1,344,858	1,300,729
Distribution	1,928,523	1,894,572
Other Property, Plant and Equipment (Including Plant to be Retired) (June 30, 2015 and December 31, 2014 Amounts Include $291,642 and $288,183, Respectively, Related to Sabine)	891,788	878,753
Construction Work in Progress	577,984	471,980
Total Property, Plant and Equipment	8,671,009	8,410,577
Accumulated Depreciation and Amortization (June 30, 2015 and December 31, 2014 Amounts Include $149,588 and $142,983, Respectively, Related to Sabine)	2,579,758	2,503,290
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,091,251	5,907,287
OTHER NONCURRENT ASSETS		
Regulatory Assets	417,551	393,602
Long-term Risk Management Assets	33	—
Deferred Charges and Other Noncurrent Assets	120,330	86,750

TOTAL OTHER NONCURRENT ASSETS	537,914	480,352
TOTAL ASSETS	$7,183,290	$6,816,893

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
June 30, 2015 and December 31, 2014
(Unaudited)

	June 30, 2015	December 31, 2014
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$138,971	$175,109
Affiliated Companies	82,129	67,410
Long-term Debt Due Within One Year – Nonaffiliated	153,250	306,750
Risk Management Liabilities	2,523	1,082
Customer Deposits	60,741	59,903
Accrued Taxes	74,559	43,965
Accrued Interest	46,139	44,328
Obligations Under Capital Leases	17,358	17,557
Other Current Liabilities	62,108	104,553
TOTAL CURRENT LIABILITIES	637,778	820,657
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,282,228	1,833,687
Deferred Income Taxes	1,397,455	1,351,111
Regulatory Liabilities and Deferred Investment Tax Credits	460,854	458,530
Asset Retirement Obligations	107,688	92,015
Employee Benefits and Pension Obligations	24,496	25,374
Obligations Under Capital Leases	83,245	91,044
Deferred Credits and Other Noncurrent Liabilities	47,634	47,274
TOTAL NONCURRENT LIABILITIES	4,403,600	3,899,035
TOTAL LIABILITIES	5,041,378	4,719,692
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 7,600,000 Shares		
Outstanding – 7,536,640 Shares	135,660	135,660
Paid-in Capital	674,606	674,606
Retained Earnings	1,338,160	1,293,986
Accumulated Other Comprehensive Income (Loss)	(6,811)	(7,466)
TOTAL COMMON SHAREHOLDER’S EQUITY	2,141,615	2,096,786
Noncontrolling Interest	297	415
TOTAL EQUITY	2,141,912	2,097,201

TOTAL LIABILITIES AND EQUITY	$7,183,290	$6,816,893

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Six Months Ended June 30,	
	2015	2014
OPERATING ACTIVITIES		
Net Income	$106,163	$55,785
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	94,918	91,525
Deferred Income Taxes	31,457	179,336
Allowance for Equity Funds Used During Construction	(11,111)	(4,278)
Mark-to-Market of Risk Management Contracts	(639)	593
Pension Contributions to Qualified Plan Trust	(8,052)	(3,832)
Property Taxes	(26,093)	(25,053)
Fuel Over/Under-Recovery, Net	4,906	(18,825)
Change in Other Noncurrent Assets	(4,443)	8,034
Change in Other Noncurrent Liabilities	(454)	(3,464)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(14,732)	21,194
Fuel, Materials and Supplies	12,153	22,914
Accounts Payable	(3,174)	8,186
Accrued Taxes, Net	36,579	(108,460)
Other Current Assets	1,428	(3,310)
Other Current Liabilities	(40,627)	(10,700)
Net Cash Flows from Operating Activities	178,279	209,645
INVESTING ACTIVITIES		
Construction Expenditures	(268,423)	(220,968)
Change in Advances to Affiliates, Net	(138,676)	—
Other Investing Activities	2,138	3,394
Net Cash Flows Used for Investing Activities	(404,961)	(217,574)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	445,949	—
Change in Advances from Affiliates, Net	—	69,918
Retirement of Long-term Debt – Nonaffiliated	(155,125)	(1,625)
Principal Payments for Capital Lease Obligations	(9,138)	(9,156)
Dividends Paid on Common Stock	(60,000)	(50,000)
Dividends Paid on Common Stock – Nonaffiliated	(2,107)	(2,309)
Other Financing Activities	764	831
Net Cash Flows from Financing Activities	220,343	7,659
Net Decrease in Cash and Cash Equivalents	(6,339)	(270)
Cash and Cash Equivalents at Beginning of Period	14,356	17,241
Cash and Cash Equivalents at End of Period	$8,017	$16,971

SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$55,799	$60,001
Net Cash Paid (Received) for Income Taxes	9,628	(7,556)
Noncash Acquisitions Under Capital Leases	1,162	3,354
Construction Expenditures Included in Current Liabilities as of June 30,	73,626	63,813

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 171.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to SWEPCo'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 SWEPCo.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to condensed financial statements that follow are a combined presentation for the Registrant Subsidiaries. The following list indicates the registrants to which the footnotes apply:

1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed 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 interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods for each Registrant Subsidiary. Net income for the three and six months ended June 30, 2015 is not necessarily indicative of results that may be expected for the year ending December 31, 2015. The condensed financial statements are unaudited and should be read in conjunction with the audited 2014 financial statements and notes thereto, which are included in the Registrant Subsidiaries' Annual Reports on Form 10-K as filed with the SEC on February 20, 2015.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to the Registrant Subsidiaries' business. The following final pronouncements will impact the financial statements.

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

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

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014. If applicable, this standard will change the presentation of financial statements but will not affect the calculation of net income, comprehensive income or earnings per share. Management adopted ASU 2014-08 effective January 1, 2015. There were no events requiring the application of this new accounting guidance.

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

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

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

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

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

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

ASU 2015-03 “Simplifying the Presentation of Debt Issuance Costs” (ASU 2015-03)

In April 2015, the FASB issued ASU 2015-03 to simplify the presentation of debt issuance costs on the balance sheets. Under the new standard, debt issuance costs related to a recognized debt liability will be presented on the balance sheets as a direct deduction from the carrying amount of that debt liability, consistent with discounts. The Registrant Subsidiaries include debt issuance costs in Deferred Charges and Other Noncurrent Assets on the condensed balance sheets. Debt issuance costs represent less than 1% of total long-term debt.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. Management intends to early adopt ASU 2015-03 for the 2015 Form 10-K.

ASU 2015-05 “Accounting for Fees Paid in a Cloud Computing Arrangement” (ASU 2015-05)

In April 2015, the FASB issued ASU 2015-05 to provide guidance to customers about whether a cloud computing arrangement includes a software license. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2015-05 effective January 1, 2016.

ASU 2015-11 “Simplifying the Measurement of Inventory” (ASU 2015-11)

In July 2015, the FASB issued ASU 2015-11 to simplify the guidance on the subsequent measurement of inventory, excluding inventory measured using last-in, first out or the retail inventory method. Under the new standard, inventory should be at the lower of cost and net realizable value. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016 with early adoption permitted. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2015-11 effective January 1, 2017.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three and six months ended June 30, 2015 and 2014. All amounts in the following tables are presented net of related income taxes.

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 30, 2015

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of March 31, 2015	$—	$4,025	$678	$4,703
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	2	(458)	(456)
Net Current Period Other Comprehensive Income (Loss)	—	2	(458)	(456)
Balance in AOCI as of June 30, 2015	$—	$4,027	$220	$4,247

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of March 31, 2014	$87	$3,343	$(566)	$2,864
Change in Fair Value Recognized in AOCI	103	—	—	103
Amounts Reclassified from AOCI	(190)	253	(333)	(270)
Net Current Period Other Comprehensive Income (Loss)	(87)	253	(333)	(167)
Balance in AOCI as of June 30, 2014	$—	$3,596	$(899)	$2,697

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2015

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of December 31, 2014	$—	$3,896	$1,136	$5,032
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	131	(916)	(785)
Net Current Period Other Comprehensive Income (Loss)	—	131	(916)	(785)
Balance in AOCI as of June 30, 2015	$—	$4,027	$220	$4,247

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of December 31, 2013	$94	$3,090	$(233)	$2,951
Change in Fair Value Recognized in AOCI	1,686	—	—	1,686
Amounts Reclassified from AOCI	(1,780)	506	(666)	(1,940)
Net Current Period Other Comprehensive Income (Loss)	(94)	506	(666)	(254)
Balance in AOCI as of June 30, 2014	$—	$3,596	$(899)	$2,697

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 30, 2015

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of March 31, 2015	$—	$(14,139)	$58	$(14,081)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	268	10	278
Net Current Period Other Comprehensive Income	—	268	10	278
Balance in AOCI as of June 30, 2015	$—	$(13,871)	$68	$(13,803)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of March 31, 2014	$61	$(15,566)	$464	$(15,041)
Change in Fair Value Recognized in AOCI	68	—	—	68
Amounts Reclassified from AOCI	(129)	411	43	325
Net Current Period Other Comprehensive Income (Loss)	(61)	411	43	393
Balance in AOCI as of June 30, 2014	$—	$(15,155)	$507	$(14,648)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2015

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of December 31, 2014	$—	$(14,406)	$46	$(14,360)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	535	22	557
Net Current Period Other Comprehensive Income	—	535	22	557
Balance in AOCI as of June 30, 2015	$—	$(13,871)	$68	$(13,803)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of December 31, 2013	$46	$(15,976)	$421	$(15,509)
Change in Fair Value Recognized in AOCI	1,130	—	—	1,130
Amounts Reclassified from AOCI	(1,176)	821	86	(269)
Net Current Period Other Comprehensive Income (Loss)	(46)	821	86	861
Balance in AOCI as of June 30, 2014	$—	$(15,155)	$507	$(14,648)

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 30, 2015

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
	(in thousands)		
Balance in AOCI as of March 31, 2015	$—	$5,259	$5,259
Change in Fair Value Recognized in AOCI	—	—	—
Amounts Reclassified from AOCI	—	(343)	(343)
Net Current Period Other Comprehensive Loss	—	(343)	(343)
Balance in AOCI as of June 30, 2015	$—	$4,916	$4,916

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 30, 2014

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
	(in thousands)		
Balance in AOCI as of March 31, 2014	$—	$6,631	$6,631
Change in Fair Value Recognized in AOCI	—	—	—
Amounts Reclassified from AOCI	—	(343)	(343)
Net Current Period Other Comprehensive Loss	—	(343)	(343)
Balance in AOCI as of June 30, 2014	$—	$6,288	$6,288

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2015

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
	(in thousands)		
Balance in AOCI as of December 31, 2014	$—	$5,602	$5,602
Change in Fair Value Recognized in AOCI	—	—	—
Amounts Reclassified from AOCI	—	(686)	(686)
Net Current Period Other Comprehensive Loss	—	(686)	(686)
Balance in AOCI as of June 30, 2015	$—	$4,916	$4,916

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2014

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
	(in thousands)		
Balance in AOCI as of December 31, 2013	$105	$6,974	$7,079
Change in Fair Value Recognized in AOCI	—	—	—
Amounts Reclassified from AOCI	(105)	(686)	(791)
Net Current Period Other Comprehensive Loss	(105)	(686)	(791)
Balance in AOCI as of June 30, 2014	$—	$6,288	$6,288

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 30, 2015

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
	(in thousands)		
Balance in AOCI as of March 31, 2015	$—	$4,753	$4,753
Change in Fair Value Recognized in AOCI	—	—	—
Amounts Reclassified from AOCI	—	(190)	(190)
Net Current Period Other Comprehensive Loss	—	(190)	(190)
Balance in AOCI as of June 30, 2015	$—	$4,563	$4,563

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 30, 2014

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
	(in thousands)		
Balance in AOCI as of March 31, 2014	$—	$5,512	$5,512
Change in Fair Value Recognized in AOCI	—	—	—
Amounts Reclassified from AOCI	—	(190)	(190)
Net Current Period Other Comprehensive Loss	—	(190)	(190)
Balance in AOCI as of June 30, 2014	$—	$5,322	$5,322

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2015

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
	(in thousands)		
Balance in AOCI as of December 31, 2014	$—	$4,943	$4,943
Change in Fair Value Recognized in AOCI	—	—	—
Amounts Reclassified from AOCI	—	(380)	(380)
Net Current Period Other Comprehensive Loss	—	(380)	(380)
Balance in AOCI as of June 30, 2015	$—	$4,563	$4,563

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2014

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
	(in thousands)		
Balance in AOCI as of December 31, 2013	$57	$5,701	$5,758
Change in Fair Value Recognized in AOCI	—	—	—
Amounts Reclassified from AOCI	(57)	(379)	(436)
Net Current Period Other Comprehensive Loss	(57)	(379)	(436)
Balance in AOCI as of June 30, 2014	$—	$5,322	$5,322

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 30, 2015

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of March 31, 2015	$—	$(10,469)	$3,330	$(7,139)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	567	(239)	328
Net Current Period Other Comprehensive Income (Loss)	—	567	(239)	328
Balance in AOCI as of June 30, 2015	$—	$(9,902)	$3,091	$(6,811)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of March 31, 2014	$—	$(12,736)	$4,560	$(8,176)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	567	(235)	332
Net Current Period Other Comprehensive Income (Loss)	—	567	(235)	332
Balance in AOCI as of June 30, 2014	$—	$(12,169)	$4,325	$(7,844)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2015

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of December 31, 2014	$—	$(11,036)	$3,570	$(7,466)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	1,134	(479)	655
Net Current Period Other Comprehensive Income (Loss)	—	1,134	(479)	655
Balance in AOCI as of June 30, 2015	$—	$(9,902)	$3,091	$(6,811)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of December 31, 2013	$66	$(13,304)	$4,794	$(8,444)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	(66)	1,135	(469)	600
Net Current Period Other Comprehensive Income (Loss)	(66)	1,135	(469)	600
Balance in AOCI as of June 30, 2014	$—	$(12,169)	$4,325	$(7,844)

Reclassifications from Accumulated Other Comprehensive Income

The following tables provide details of reclassifications from AOCI for the three and six months ended June 30, 2015 and 2014. 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.

APCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended June 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI Three Months Ended June 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Purchased Electricity for Resale	$—	$(64)
Regulatory Assets/(Liabilities), Net (a)	—	(228)
Subtotal – Commodity	—	(292)
Interest Rate and Foreign Currency:		
Interest Expense	3	390
Subtotal – Interest Rate and Foreign Currency	3	390
Reclassifications from AOCI, before Income Tax (Expense) Credit	3	98
Income Tax (Expense) Credit	1	35
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	2	63
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(1,283)	(1,283)
Amortization of Actuarial (Gains)/Losses	578	770
Reclassifications from AOCI, before Income Tax (Expense) Credit	(705)	(513)
Income Tax (Expense) Credit	(247)	(180)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(458)	(333)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$(456)	$(270)

APCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Six Months Ended June 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI Six Months Ended June 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Purchased Electricity for Resale	$—	$(526)
Other Operation Expense	—	(10)
Maintenance Expense	—	(20)
Property, Plant and Equipment	—	(17)
Regulatory Assets/(Liabilities), Net (a)	—	(2,165)
Subtotal – Commodity	—	(2,738)
Interest Rate and Foreign Currency:		
Interest Expense	202	780
Subtotal – Interest Rate and Foreign Currency	202	780
Reclassifications from AOCI, before Income Tax (Expense) Credit	202	(1,958)
Income Tax (Expense) Credit	71	(684)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	131	(1,274)
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(2,565)	(2,565)
Amortization of Actuarial (Gains)/Losses	1,156	1,540
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1,409)	(1,025)
Income Tax (Expense) Credit	(493)	(359)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(916)	(666)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$(785)	$(1,940)

I&M

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended June 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI Three Months Ended June 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Purchased Electricity for Resale	$—	$(95)
Regulatory Assets/(Liabilities), Net (a)	—	(103)
Subtotal – Commodity	—	(198)
Interest Rate and Foreign Currency:		
Interest Expense	411	631
Subtotal – Interest Rate and Foreign Currency	411	631
Reclassifications from AOCI, before Income Tax (Expense) Credit	411	433
Income Tax (Expense) Credit	143	151
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	268	282
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(199)	(198)
Amortization of Actuarial (Gains)/Losses	215	262
Reclassifications from AOCI, before Income Tax (Expense) Credit	16	64
Income Tax (Expense) Credit	6	21
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	10	43
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$278	$325

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I&M

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Six Months Ended June 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI Six Months Ended June 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Purchased Electricity for Resale	$—	$(812)
Other Operation Expense	—	(7)
Maintenance Expense	—	(7)
Property, Plant and Equipment	—	(10)
Regulatory Assets/(Liabilities), Net (a)	—	(973)
Subtotal – Commodity	—	(1,809)
Interest Rate and Foreign Currency:		
Interest Expense	822	1,262
Subtotal – Interest Rate and Foreign Currency	822	1,262
Reclassifications from AOCI, before Income Tax (Expense) Credit	822	(547)
Income Tax (Expense) Credit	287	(192)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	535	(355)
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(398)	(397)
Amortization of Actuarial (Gains)/Losses	432	527
Reclassifications from AOCI, before Income Tax (Expense) Credit	34	130
Income Tax (Expense) Credit	12	44
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	22	86
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$557	$(269)

OPCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended June 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI Three Months Ended June 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Other Operation Expense	$—	$—
Maintenance Expense	—	—
Property, Plant and Equipment	—	—
Regulatory Assets/(Liabilities), Net (a)	—	—
Subtotal – Commodity	—	—
Interest Rate and Foreign Currency:		
Depreciation and Amortization Expense	(3)	(3)
Interest Expense	(524)	(524)
Subtotal – Interest Rate and Foreign Currency	(527)	(527)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(527)	(527)
Income Tax (Expense) Credit	(184)	(184)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$(343)	$(343)

OPCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Six Months Ended June 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI Six Months Ended June 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Other Operation Expense	$—	$(11)
Maintenance Expense	—	(11)
Property, Plant and Equipment	—	(18)
Regulatory Assets/(Liabilities), Net (a)	—	(122)
Subtotal – Commodity	—	(162)
Interest Rate and Foreign Currency:		
Depreciation and Amortization Expense	(6)	(6)
Interest Expense	(1,048)	(1,048)
Subtotal – Interest Rate and Foreign Currency	(1,054)	(1,054)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1,054)	(1,216)
Income Tax (Expense) Credit	(368)	(425)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$(686)	$(791)

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PSO

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended June 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI Three Months Ended June 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Other Operation Expense	$—	$—
Maintenance Expense	—	—
Property, Plant and Equipment	—	—
Regulatory Assets/(Liabilities), Net (a)	—	—
Subtotal – Commodity	—	—
Interest Rate and Foreign Currency:		
Interest Expense	(292)	(292)
Subtotal – Interest Rate and Foreign Currency	(292)	(292)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(292)	(292)
Income Tax (Expense) Credit	(102)	(102)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$(190)	$(190)

PSO

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Six Months Ended June 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI Six Months Ended June 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Other Operation Expense	$—	$(8)
Maintenance Expense	—	(9)
Property, Plant and Equipment	—	(13)
Regulatory Assets/(Liabilities), Net (a)	—	(58)
Subtotal – Commodity	—	(88)
Interest Rate and Foreign Currency:		
Interest Expense	(584)	(584)
Subtotal – Interest Rate and Foreign Currency	(584)	(584)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(584)	(672)
Income Tax (Expense) Credit	(204)	(236)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$(380)	$(436)

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SWEPCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended June 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI Three Months Ended June 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Other Operation Expense	$—	$—
Maintenance Expense	—	—
Property, Plant and Equipment	—	—
Regulatory Assets/(Liabilities), Net (a)	—	—
Subtotal – Commodity	—	—
Interest Rate and Foreign Currency:		
Interest Expense	872	872
Subtotal – Interest Rate and Foreign Currency	872	872
Reclassifications from AOCI, before Income Tax (Expense) Credit	872	872
Income Tax (Expense) Credit	305	305
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	567	567
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(467)	(477)
Amortization of Actuarial (Gains)/Losses	99	115
Reclassifications from AOCI, before Income Tax (Expense) Credit	(368)	(362)
Income Tax (Expense) Credit	(129)	(127)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(239)	(235)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$328	$332

SWEPCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Six Months Ended June 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI Six Months Ended June 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Other Operation Expense	$—	$(13)
Maintenance Expense	—	(10)
Property, Plant and Equipment	—	(11)
Regulatory Assets/(Liabilities), Net (a)	—	(67)
Subtotal – Commodity	—	(101)
Interest Rate and Foreign Currency:		
Interest Expense	1,744	1,744
Subtotal – Interest Rate and Foreign Currency	1,744	1,744
Reclassifications from AOCI, before Income Tax (Expense) Credit	1,744	1,643
Income Tax (Expense) Credit	610	574
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1,134	1,069
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(934)	(955)
Amortization of Actuarial (Gains)/Losses	197	233
Reclassifications from AOCI, before Income Tax (Expense) Credit	(737)	(722)
Income Tax (Expense) Credit	(258)	(253)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(479)	(469)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$655	$600

(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 2014 Annual Report, the Registrant Subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2014 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 2015 and updates the 2014 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

	APCo	
	June 30, 2015	December 31, 2014
Noncurrent Regulatory Assets	(in thousands)	
Regulatory Assets Currently Earning a Return		
Materials and Supplies Related to Retired Plants	$7,588	$—
Vegetation Management Program – West Virginia	—	19,089
Regulatory Assets Currently Not Earning a Return		
Asset Retirement Obligation Costs Related to Retired Plants	24,399	—
Demand Response Program Costs – Virginia	10,781	8,791
Amos Plant Transfer Costs – West Virginia	1,950	1,377
Storm Related Costs – West Virginia	—	65,206
Carbon Capture and Storage Product Validation Facility – West Virginia, FERC	—	13,264
IGCC Pre-Construction Costs – West Virginia, FERC	—	10,838
Expanded Net Energy Charge – Coal Inventory	—	3,421
Expanded Net Energy Charge – Construction Surcharge	—	2,307
Carbon Capture and Storage Commercial Scale Facility – West Virginia, FERC	—	1,287
Other Regulatory Assets Pending Final Regulatory Approval	168	168
Total Regulatory Assets Pending Final Regulatory Approval	$44,886	$125,748

	I&M	
	June 30, 2015	December 31, 2014
Noncurrent Regulatory Assets	(in thousands)	
Regulatory Assets Currently Earning a Return		
Materials and Supplies Related to Retired Plants	$11,722	$—
Regulatory Assets Currently Not Earning a Return		
Asset Retirement Obligation Costs Related to Retired Plants	27,079	—
Cook Plant Turbine	8,169	6,596
Stranded Costs on Abandoned Plants	3,897	3,897
Deferred Cook Plant Life Cycle Management Project Costs – Michigan	2,721	1,222
Storm Related Costs – Indiana	857	1,074
Other Regulatory Assets Pending Final Regulatory Approval	547	860
Total Regulatory Assets Pending Final Regulatory Approval	$54,992	$13,649

	OPCo	
	June 30, 2015	December 31, 2014
Noncurrent Regulatory Assets	(in thousands)	
Regulatory Assets Currently Not Earning a Return		
Ormet Special Rate Recovery Mechanism	$10,483	$10,483
Other Regulatory Assets Pending Final Regulatory Approval	44	—
Total Regulatory Assets Pending Final Regulatory Approval	$10,527	$10,483

	PSO	
	June 30, 2015	December 31, 2014
Noncurrent Regulatory Assets	(in thousands)	
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	$—	$16,614
Other Regulatory Assets Pending Final Regulatory Approval	—	1,079
Total Regulatory Assets Pending Final Regulatory Approval	$—	$17,693

	SWEPCo	
	June 30, 2015	December 31, 2014
Noncurrent Regulatory Assets	(in thousands)	
Regulatory Assets Currently Not Earning a Return		
Rate Case Expenses	$—	$8,126
Shipe Road Transmission Project	3,022	2,287
Asset Retirement Obligation	1,320	1,144
Other Regulatory Assets Pending Final Regulatory Approval	558	558
Total Regulatory Assets Pending Final Regulatory Approval	$4,900	$12,115

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. 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.

In August 2012, the PUCO issued an order in a separate proceeding which implemented a PIRR to recover deferred fuel costs in rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. In November 2012, OPCo appealed that PUCO order to the Supreme Court of Ohio claiming a long-term debt rate modified the previously adjudicated 2009 - 2011 ESP order, which granted a weighted average cost of capital (WACC) rate. In November 2012, the IEU filed an appeal of the PUCO decision that included the argument that carrying costs should be reduced due to an accumulated deferred income tax credit. In June 2015, the Supreme Court of Ohio issued a decision that reversed the PUCO order on the carrying cost rate issue and dismissed the appeal filed by the IEU. In June 2015, the IEU filed a motion for reconsideration with the Supreme Court of Ohio related to the accumulated deferred income tax credit. If the Supreme Court of Ohio upholds its June 2015 order, it would remand the matter back to the PUCO for reinstatement of the WACC rate.

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

June 2012 – May 2015 ESP Including Capacity Charge

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

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

As part of the August 2012 ESP order, the PUCO established a non-bypassable RSR, effective September 2012. The RSR was collected from customers at $3.50/MWh through May 2014 and 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 July 2014, OPCo submitted a separate application to continue the RSR to collect the unrecovered portion of the deferred capacity costs at the rate of $4.00/MWh until the balance of the capacity deferrals has been collected. In April 2015, the PUCO issued an order approving the application to continue the RSR, with modifications. The order included approval to continue the collection of deferred capacity costs at a rate of $4.00/MWh beginning June 1, 2015 for approximately 32 months, with carrying costs at a long-term cost of debt rate. Additionally, the order stated that an audit will be conducted of the May 31, 2015 capacity deferral balance, which was $444 million. In May 2015, the PUCO granted intervenors requests for rehearing. As of June 30, 2015, OPCo's incurred deferred capacity costs balance of $432 million, including debt carrying costs, was recorded in Regulatory Assets on the condensed balance sheet.

In 2013, the PUCO issued its Orders on Rehearing for the ESP which generally upheld its August 2012 order. The PUCO clarified that a final reconciliation of revenues and expenses would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket related to the competitive bid process (CBP). In 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO's ESP order. Oral arguments at the Supreme Court of Ohio were held in May 2015.

In November 2013, the PUCO issued an order approving OPCo's CBP with modifications. As ordered, in 2014, OPCo conducted multiple energy-only auctions for a total of 100% of the SSO load with delivery beginning April 2014 through May 2015. As provided for in the June 2015 - May 2018 ESP, for delivery starting in June 2015, OPCo now conducts energy and capacity auctions for its entire SSO load. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings.

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

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

June 2015 - May 2018 ESP

In December 2013, OPCo filed an application with the PUCO to approve an ESP that included proposed rate adjustments and the continuation and modification of certain existing riders, including the Distribution Investment Rider (DIR), effective June 2015 through May 2018. The proposal included a return on common equity of 10.65% on capital costs for certain riders. The proposal also included a purchased power agreement (PPA) rider that would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based PPA. The PPA would initially be based upon the OVEC contractual entitlement and could, upon further approval, be expanded to include other contracts involving other Ohio legacy generation assets. In October 2014, OPCo filed a separate application with the PUCO to propose a new extended PPA with AGR for 2,671 MW for inclusion in the PPA rider.

In February 2015, the PUCO issued an order approving OPCo's ESP application, subject to certain modifications, with a return on common equity of 10.2% on capital costs for certain riders. The order included (a) approval of the DIR with modified rate caps established by the PUCO, (b) authorization to establish a zero rate rider for OPCo's proposed PPA, (c) the option for OPCo to reapply in a future proceeding with a more detailed PPA proposal and (d) a directive to continue to pursue the transfer of the OVEC contractual entitlement to AGR or to otherwise divest of its interest in OVEC. In May 2015, on rehearing, the PUCO issued an order that increased the DIR rate caps and deferred ruling on all requests for rehearing related to the establishment of the PPA rider. In June 2015, OPCo and various intervenors filed applications for rehearing with the PUCO related to the May 2015 order on rehearing. In July 2015, the PUCO granted the requests for rehearing.

In May 2015, OPCo filed an amended PPA application between OPCo and AGR that (a) included OPCo's OVEC contractual entitlement, (b) addressed the PPA requirements set forth in the PUCO's February 2015 order, (c) updated supporting testimony to reflect a current analysis of the PPA proposal and (d) continued to include the 2,671 MW to be available for capacity, energy and ancillary services, produced by AGR over the lives of the respective generating units.

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

Significantly Excessive Earnings Test Filings

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

In June 2015, OPCo filed its 2014 SEET filing with the PUCO. Management believes its financial statements adequately address the impact of 2014 SEET requirements.

Corporate Separation

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

2009 Fuel Adjustment Clause Audit

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

In September 2014, the Supreme Court of Ohio upheld the PUCO order on appeal. A review of the coal reserve valuation by an outside consultant has not been initiated by the PUCO. 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.

2012 and 2013 Fuel Adjustment Clause Audits

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

Ormet

Ormet, a large aluminum company, had a contract to purchase power from OPCo through 2018. In 2013, Ormet filed for bankruptcy and subsequently shut down operations. In March 2014, the PUCO issued an order in OPCo’s Economic Development Rider (EDR) filing allowing OPCo to include $39 million of Ormet-related foregone revenues in the EDR effective April 2014. The order stated that if the stipulation agreement between OPCo and Ormet is subsequently adopted by the PUCO, OPCo could file an application to modify the EDR rate for the remainder of the period requesting recovery of the remaining $10 million of Ormet deferrals which, as of June 30, 2015, is recorded in Regulatory Assets on the condensed balance sheet. In April 2014, an intervenor filed testimony objecting to $5 million of the remaining foregone revenues. A hearing at the PUCO related to the stipulation agreement was held in May 2014.

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

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

SWEPCo Rate Matters

2012 Texas Base Rate Case

In 2012, SWEPCo filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In 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 June 30, 2015, the net book value of Welsh Plant, Unit 2 was $83 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 and in April 2014, this order became final. In May 2014, intervenors filed appeals of that order with the Texas District Court. In June 2014, SWEPCo intervened in those appeals and filed initial responses.

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

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

2014 Louisiana Formula Rate Filing

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

2015 Louisiana Formula Rate Filing

In April 2015, SWEPCo filed its formula rate plan for test year 2014 with the LPSC. The filing included a $14 million annual increase, which will be effective August 2015. This increase is subject to LPSC staff review and is subject to refund. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Welsh Plant, Units 1 and 3 – Environmental Projects

To comply with pending Federal EPA regulations, SWEPCo is currently constructing environmental control projects to meet mercury and air toxics standards for Welsh Plant, Units 1 and 3 at a cost of approximately $410 million, excluding AFUDC. Management currently estimates that the total environmental projects to be completed through 2020 for Welsh Plant, Units 1 and 3 will cost approximately $600 million, excluding AFUDC. As of June 30, 2015, SWEPCo has incurred costs of $256 million, including AFUDC, and has remaining contractual construction obligations of $89 million related to these projects. SWEPCo will seek recovery of these project costs from customers through filings at the state commissions and the FERC. As of June 30, 2015, the net book value of Welsh Plant, Units 1 and 3 was $484 million, before cost of removal, including materials and supplies inventory and CWIP. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

APCo Rate Matters

2014 West Virginia Base Rate Case

In June 2014, APCo filed a request with the WVPSC to increase annual base rates by $156 million, based upon a 10.62% return on common equity, to be effective in the second quarter of 2015. The filing included a request to increase generation depreciation rates primarily due to the increase in plant investment and changes in the expected service lives of various generating units. The filing also requested recovery of $77 million in regulatory assets over five years related to 2012 West Virginia storm costs, IGCC and other deferred costs. In addition to the base rate request, the filing also included a request to implement a rider of approximately $38 million annually to recover vegetation management costs, including a return on capital investment.

In May 2015, the WVPSC issued an order on the base rate case. Upon implementation of the order in May 2015, and consistent with the WVPSC authorized total revenue, annual base rates were authorized to be increased by $85 million based upon a 9.75% return on common equity. The order included a delayed billing of $22 million of the annual base rate increase to residential customers until July 2016. The order provided for carrying charges based upon a WACC rate for the $22 million annual delayed billing through June 2016, and stated recovery would be addressed in the next ENEC case scheduled for 2016. Additionally, the order included approval of (a) an initial vegetation management rider of $38 million annually, (b) revised deprecation rates, including recovery of plants to be retired and (c) the recovery of $77 million in previously recorded regulatory assets, which will predominantly be recovered over five years.

In June 2015, the WVPSC staff and intervenors filed motions for reconsideration and clarification related to various issues including recovery of lost revenues and the allowed carrying charge rate related to the delayed residential revenues. In July 2015, the WVPSC issued an order that denied all motions for reconsideration.

2015 Virginia Regulatory Asset Proceeding

In January 2015, the Virginia SCC initiated a separate proceeding to address the proper treatment of APCo’s authorized regulatory assets. As of June 30, 2015, APCo’s authorized regulatory assets under review in this proceeding are estimated to be $12 million. In February and March 2015, briefs related to this proceeding were filed by various parties. If any of these costs, or any additional costs that may be subject to review, are not recoverable, it could reduce future net income and cash flows and impact financial condition.

New Virginia Legislation Affecting Biennial Reviews

In February 2015, amendments to Virginia law governing the regulation of investor-owned electric utilities were enacted. Under the amended Virginia law, APCo's existing generation and distribution base rates are frozen until after the Virginia SCC rules on APCo's next biennial review, which APCo will file in March 2020 for the 2018 and 2019 test years. These amendments also preclude the Virginia SCC from performing biennial reviews of APCo's earnings for the years 2014 through 2017. APCo's financial statements adequately address the impact of these amendments. The new law provides that APCo will absorb its Virginia jurisdictional share of incremental generation and distribution costs incurred during 2014 through 2017 that are associated with severe weather events and/or natural disasters and costs associated with potential impairments related to new carbon emission guidelines issued by the Federal EPA.

PSO Rate Matters

2015 Oklahoma Base Rate Case

In July 2015, PSO filed a request with the OCC to increase annual revenues by $137 million to recover costs associated with its environmental compliance plan for the Federal EPA's Regional Haze Rule and Mercury and Air Toxics Standards, and to recover investments and other costs that have increased since the last base rate case. The annual increase consists of (a) a base rate increase of $89 million, which includes $48 million in increased depreciation expense that reflects, among other things, recovery through June 2026 for Northeastern Plant, Units 3 and 4, (b) a rider or base rate increase of $44 million to recover costs for the environmental controls being installed on Northeastern Plant, Unit 3 and the Comanche Plant and (c) a request to include environmental consumable costs in the FAC, estimated to be $4 million annually. The rate increase includes a proposed return on equity of 10.5% and is proposed to be effective in January 2016, except for the $44 million for environmental investments, which is proposed to be effective in March 2016, after the Northeastern Plant, Unit 3 environmental controls go in service. The total estimated cost of the environmental controls to be installed at Northeastern Plant, Unit 3 and the Comanche Plant is $219 million, excluding AFUDC. As of June 30, 2015, PSO has incurred costs of $140 million related to these projects, including AFUDC.

In addition, the filing also notified the OCC that future incremental purchased capacity and energy costs of an estimated $35 million will be incurred related to the environmental compliance plan, due to the closure of Northeastern Plant, Unit 4 in April 2016, which would be recovered through the FAC. As of June 30, 2015, the net book value of Northeastern Plant, Unit 4 was $95 million, before cost of removal, including materials and supplies inventory and CWIP.

If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2014 Oklahoma Base Rate Case

In April 2015, the OCC issued an order that approved a non-unanimous stipulation agreement between PSO, the OCC staff and certain intervenors. The approved stipulation provides for no overall change to the transmission rider or to annual revenues, other than additional revenues through a separate rider related to advanced metering costs, and that the terms of the stipulation be effective November 2014. The advanced metering rider provides $24 million of revenues over 14 months beginning in November 2014 and increases to $27 million in 2016. The stipulation also included (a) new depreciation rates for advanced metering investments and existing meters, also effective November 2014, (b) a return on common equity of 9.85% to be used only in the formula to calculate AFUDC, factoring of customer receivables and for riders with an equity component and (c) recovery of regulatory assets for 2013 storms and regulatory case expenses. The advanced metering cost rider was implemented in November 2014.

I&M Rate Matters

Tanners Creek Plant

In October 2014, I&M filed an application with the IURC seeking approval of revised depreciation rates for Rockport Plant, Unit 1 and the Tanners Creek Plant. Upon retirement of the Tanners Creek Plant, I&M proposed that, for purposes of determining its depreciation rates, the net book value of the Tanners Creek Plant be recovered over the remaining life of the Rockport Plant. The new depreciation rates would result in a decrease in I&M's Indiana jurisdictional electric depreciation expense which I&M proposed to reduce customer rates through a credit rider. In May 2015, the IURC issued an order approving I&M's request for revised depreciation rates.

In May 2015, Tanners Creek Plant was retired. Upon retirement, $265 million was reclassified as Regulatory Assets on the condensed balance sheet related to the net book value of Tanners Creek Plant and is being amortized over 29 years. An additional $38 million was reclassified as Regulatory Assets on the condensed balance sheet for related asset retirement obligations and materials and supplies. These additional regulatory assets are currently not being amortized, pending regulatory approval.

Transmission, Distribution and Storage System Improvement Charge (TDSIC)

In October 2014, I&M filed petitions with the IURC for approval of a TDSIC Rider and approval of I&M’s seven-year TDSIC Plan, from 2015 through 2021, for eligible transmission, distribution and storage system improvements. The initial estimated cost of the capital improvements and associated operation and maintenance expenses included in the TDSIC Plan of $787 million, excluding AFUDC, would be updated annually. The TDSIC Plan included distribution investments specific to the Indiana jurisdiction. The TDSIC Rider would allow the periodic adjustment of I&M's rates to provide for timely recovery of 80% of approved TDSIC Plan costs. I&M would defer the remaining 20% of approved TDSIC Plan costs to be recovered in I&M's next general rate case. I&M did not seek a rate adjustment in this proceeding but sought approval of a TDSIC Rider rate adjustment mechanism for subsequent proceedings. In April 2015, I&M filed a notice with the IURC to seek approval of the proposed TDSIC Plan excluding $117 million of certain projects that were challenged in this proceeding. In May 2015, the IURC issued an order that denied I&M's TDSIC Plan and Rider. In May 2015, I&M filed a petition for reconsideration and/or rehearing with the IURC and in June 2015, filed a notice of appeal with the Indiana Court of Appeals.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The Registrant Subsidiaries are subject to certain claims and legal actions arising in their ordinary course of business. In addition, their business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation 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 the financial statements. The Commitments, Guarantees and Contingencies note within the 2014 Annual Report should be read in conjunction with this report.

GUARANTEES

Liabilities for guarantees are recorded 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 – Affecting APCo, I&M and OPCo

Certain Registrant Subsidiaries enter into standby letters of credit with third parties. These letters of credit are issued in the ordinary course of business and cover items such as insurance programs, security deposits and debt service reserves.

AEP has two revolving credit facilities totaling $3.5 billion, under which up to $1.2 billion may be issued as letters of credit. As of June 30, 2015, the maximum future payments for letters of credit issued under the revolving credit facilities were as follows:

Company	Amount (in thousands)	Maturity
I&M	$35	March 2016
OPCo	4,200	June 2016

The Registrant Subsidiaries have $307 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $310 million as follows:

Company	Pollution Control Bonds	Bilateral Letters of Credit	Maturity of Bilateral Letters of Credit
	(in thousands)		
APCo	$229,650	$232,293	March 2016 to March 2017
I&M	77,000	77,886	March 2017

Guarantees of Third-Party Obligations – Affecting 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, it is estimated the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of $58 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of June 30, 2015, SWEPCo has collected $65 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 $49 million is recorded in Asset Retirement Obligations on SWEPCo's 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 – Affecting APCo, I&M, OPCo, PSO and SWEPCo

Contracts

The Registrant Subsidiaries enter into certain 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, exposure generally does not exceed the sale price. As of June 30, 2015, there were no material liabilities recorded for any indemnifications.

APCo, I&M and OPCo are jointly and severally liable for activity conducted by AEPSC on behalf of AEP companies related to power purchase and sale activity pursuant to the SIA. PSO and SWEPCo are jointly and severally liable for activity conducted by AEPSC on behalf of PSO and SWEPCo related to power purchase and sale activity pursuant to the SIA.

Master Lease Agreements

The Registrant Subsidiaries 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, the Registrant Subsidiaries 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 June 30, 2015, the maximum potential loss by Registrant Subsidiary for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term was as follows:

Company	Maximum Potential Loss (in thousands)
APCo	$4,864
I&M	3,323
OPCo	5,618
PSO	2,428
SWEPCo	2,825

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 assignments are accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $11 million and $12 million for I&M and SWEPCo, respectively, for the remaining railcars as of June 30, 2015.

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 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 $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, management believes 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 – Affecting I&M

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, the generation plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. The Registrant Subsidiaries 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. In 2014, I&M recorded an accrual for remediation at certain additional sites in Michigan. As a result of receiving approval of completed remediation work from the MDEQ in March 2015, I&M's accrual for all of these sites was reduced. As of June 30, 2015, I&M's accrual for all of these sites is approximately $9 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 sites or changes in the scope of remediation. Management cannot predict the amount of additional cost, if any.

NUCLEAR CONTINGENCIES – AFFECTING I&M

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission. I&M has 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 generation 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 – Affecting I&M

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 a motion to transfer this case to the U.S. District Court for the Southern District of Ohio. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M. In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiffs’ claims. Several claims remain, including the claim for breach of the participation agreement and a claim alleging breach of an implied covenant of good faith and fair dealing. In June 2015, AEGCo and I&M filed a motion for partial judgment on the claims seeking dismissal of the breach of participation agreement claim as well as any claim for indemnification of costs associated with this case. In July 2015, the plaintiffs responded to the motion for partial judgment and simultaneously moved for partial summary judgment on their claims for breach of the lease and participation agreement. Management will continue to defend against the remaining claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Wage and Hours Lawsuit – Affecting PSO

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

In March 2014, the federal court granted plaintiffs' motion to conditionally certify the action as a class action. Notice was given to all potential class members and an additional 44 individuals opted in to the class, bringing the plaintiff class to 80 current and former employees. Two plaintiffs have since dismissed their claims without prejudice, leaving 78 plaintiffs. Management will continue to defend the case. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Gavin Landfill Litigation – Affecting OPCo

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

6. BENEFIT PLANS

The Registrant Subsidiaries participate in an AEP sponsored qualified pension plan and two unfunded nonqualified pension plans. Substantially all employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. The Registrant Subsidiaries also participate in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees.

Components of Net Periodic Benefit Cost

The following tables provide the components of net periodic benefit cost (credit) by Registrant Subsidiary for the plans for the three and six months ended June 30, 2015 and 2014:

APCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$2,175	$1,759	$285	$362
Interest Cost	6,679	7,406	2,585	3,197
Expected Return on Plan Assets	(8,746)	(8,481)	(4,529)	(4,633)
Amortization of Prior Service Cost (Credit)	45	49	(2,512)	(2,512)
Amortization of Net Actuarial Loss	3,474	4,148	899	1,145
Net Periodic Benefit Cost (Credit)	$3,627	$4,881	$(3,272)	$(2,441)

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$4,350	$3,518	$571	$724
Interest Cost	13,358	14,812	5,169	6,394
Expected Return on Plan Assets	(17,491)	(16,963)	(9,058)	(9,266)
Amortization of Prior Service Cost (Credit)	90	99	(5,025)	(5,025)
Amortization of Net Actuarial Loss	6,947	8,296	1,799	2,291
Net Periodic Benefit Cost (Credit)	$7,254	$9,762	$(6,544)	$(4,882)

I&M

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$3,217	$2,517	$407	$487
Interest Cost	6,115	6,574	1,592	1,910
Expected Return on Plan Assets	(8,116)	(7,748)	(3,304)	(3,363)
Amortization of Prior Service Cost (Credit)	46	48	(2,356)	(2,356)
Amortization of Net Actuarial Loss	3,144	3,646	507	592
Net Periodic Benefit Cost (Credit)	$4,406	$5,037	$(3,154)	$(2,730)

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$6,434	$5,034	$813	$974
Interest Cost	12,230	13,147	3,184	3,819
Expected Return on Plan Assets	(16,232)	(15,496)	(6,608)	(6,727)
Amortization of Prior Service Cost (Credit)	91	97	(4,711)	(4,711)
Amortization of Net Actuarial Loss	6,289	7,292	1,013	1,184
Net Periodic Benefit Cost (Credit)	$8,812	$10,074	$(6,309)	$(5,461)

OPCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$1,672	$1,285	$215	$257
Interest Cost	5,070	5,526	1,615	1,900
Expected Return on Plan Assets	(6,878)	(6,606)	(3,378)	(3,380)
Amortization of Prior Service Cost (Credit)	35	39	(1,730)	(1,730)
Amortization of Net Actuarial Loss	2,644	3,105	518	595
Net Periodic Benefit Cost (Credit)	$2,543	$3,349	$(2,760)	$(2,358)

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$3,344	$2,570	$431	$513
Interest Cost	10,140	11,052	3,230	3,801
Expected Return on Plan Assets	(13,756)	(13,213)	(6,754)	(6,760)
Amortization of Prior Service Cost (Credit)	70	78	(3,461)	(3,461)

Amortization of Net Actuarial Loss	5,288	6,211	1,035	1,190
Net Periodic Benefit Cost (Credit)	$5,086	$6,698	$(5,519)	$(4,717)

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PSO

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$1,599	$1,302	$169	$210
Interest Cost	2,732	3,014	759	894
Expected Return on Plan Assets	(3,786)	(3,651)	(1,577)	(1,575)
Amortization of Prior Service Cost (Credit)	63	74	(1,072)	(1,073)
Amortization of Net Actuarial Loss	1,417	1,688	241	277
Net Periodic Benefit Cost (Credit)	$2,025	$2,427	$(1,480)	$(1,267)

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$3,198	$2,604	$339	$420
Interest Cost	5,463	6,028	1,518	1,787
Expected Return on Plan Assets	(7,572)	(7,302)	(3,154)	(3,150)
Amortization of Prior Service Cost (Credit)	126	148	(2,145)	(2,145)
Amortization of Net Actuarial Loss	2,834	3,376	483	554
Net Periodic Benefit Cost (Credit)	$4,049	$4,854	$(2,959)	$(2,534)

SWEPCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$2,082	$1,654	$210	$253
Interest Cost	2,932	3,162	838	998
Expected Return on Plan Assets	(4,008)	(3,857)	(1,736)	(1,754)
Amortization of Prior Service Cost (Credit)	77	88	(1,289)	(1,289)
Amortization of Net Actuarial Loss	1,507	1,762	266	308
Net Periodic Benefit Cost (Credit)	$2,590	$2,809	$(1,711)	$(1,484)

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$4,163	$3,309	$421	$506
Interest Cost	5,864	6,325	1,675	1,996
Expected Return on Plan Assets	(8,016)	(7,714)	(3,471)	(3,508)
Amortization of Prior Service Cost (Credit)	154	175	(2,578)	(2,578)

Amortization of Net Actuarial Loss	3,014	3,523	532	617
Net Periodic Benefit Cost (Credit)	$5,179	$5,618	$(3,421)	$(2,967)

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7. BUSINESS SEGMENTS

The Registrant Subsidiaries each have one reportable segment, an integrated electricity generation, transmission and distribution business, except OPCo, an electricity transmission and distribution business that started in 2014. The Registrant Subsidiaries' other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

The Registrant Subsidiaries are exposed to certain market risks as major power producers and participants in the wholesale electricity, natural gas, coal and emission allowance markets. 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 the Registrant Subsidiaries due to changes in the underlying market prices or rates. AEPSC, on behalf of the Registrant Subsidiaries, manages these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The 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 AEPSC transacts on behalf of the Registrant Subsidiaries. To accomplish these objectives, AEPSC, on behalf of the Registrant Subsidiaries, primarily employs 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.

AEPSC, on behalf of the Registrant Subsidiaries, enters 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 the energy business. AEPSC, on behalf of the Registrant Subsidiaries, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with the Registrant Subsidiaries’ commodity portfolio. For disclosure purposes, such risks are grouped as “Commodity,” as these risks are related to energy risk management activities. AEPSC, on behalf of the Registrant Subsidiaries, also engages 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 established risk management policies as approved by the Finance Committee of AEP’s Board of Directors.

The following tables represent the gross notional volume of the Registrant Subsidiaries' outstanding derivative contracts as of June 30, 2015 and December 31, 2014:

Notional Volume of Derivative Instruments
June 30, 2015

Primary Risk Exposure	Unit of Measure	APCo	I&M	OPCo	PSO	SWEPCo
		(in thousands)				
Commodity:						
Power	MWhs	82,828	38,036	5,428	26,530	31,839
Coal	Tons	232	250	—	—	750
Natural Gas	MMBtus	339	227	—	12	14
Heating Oil and Gasoline	Gallons	1,468	695	1,546	852	975
Interest Rate	USD	$3,590	$2,435	$—	$—	$—

Notional Volume of Derivative Instruments
December 31, 2014

Primary Risk Exposure	Unit of Measure	APCo	I&M	OPCo	PSO	SWEPCo
		(in thousands)				
Commodity:						
Power	MWhs	32,479	23,774	20,334	16,765	20,469
Coal	Tons	279	500	—	—	1,500
Natural Gas	MMBtus	421	286	—	—	—
Heating Oil and Gasoline	Gallons	1,089	521	1,108	614	699
Interest Rate	USD	$5,094	$3,455	$—	$—	$—

Cash Flow Hedging Strategies

AEPSC, on behalf of the Registrant Subsidiaries, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of power ("Commodity") in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. The Registrant Subsidiaries do not hedge all commodity price risk.

The Registrant Subsidiaries' vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of the Registrant Subsidiaries, enters into financial heating oil and gasoline derivative contracts in order to mitigate price risk of future fuel purchases. Cash flow hedge accounting for these derivative contracts was discontinued effective March 31, 2014. In March 2014, these contracts were grouped as "Commodity" with other risk management activities. The Registrant Subsidiaries do not hedge all fuel price risk.

AEPSC, on behalf of the Registrant Subsidiaries, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. AEPSC, on behalf of the Registrant Subsidiaries, also enters into interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. The Registrant Subsidiaries do not hedge all interest rate exposure.

At times, the Registrant Subsidiaries are exposed to foreign currency exchange rate risks primarily when some fixed assets are purchased from foreign suppliers. In accordance with AEP’s risk management policy, AEPSC, on behalf of the Registrant Subsidiaries, 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. The Registrant Subsidiaries do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE 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 sheet 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 the derivative instruments, the Registrant Subsidiaries 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 management's 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 risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," the Registrant Subsidiaries reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrant Subsidiaries are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the June 30, 2015 and December 31, 2014 condensed balance sheets, the Registrant Subsidiaries netted cash collateral received from third parties against short-term and long-term risk management assets and cash collateral paid to third parties against short-term and long-term risk management liabilities as follows:

Company	June 30, 2015 Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities	December 31, 2014 Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities
	(in thousands)			
APCo	$—	$915	$68	$98
I&M	—	428	163	47
OPCo	—	121	—	102
PSO	—	115	—	54
SWEPCo	—	134	—	62

The following tables represent the gross fair value of the Registrant Subsidiaries' derivative activity on the condensed balance sheets as of June 30, 2015 and December 31, 2014:

APCo

Fair Value of Derivative Instruments
June 30, 2015

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$52,015	$—	$—	$52,015	$(13,138)	$38,877
Long-term Risk Management Assets	3,286	—	—	3,286	(284)	3,002
Total Assets	55,301	—	—	55,301	(13,422)	41,879
Current Risk Management Liabilities	23,210	—	—	23,210	(14,051)	9,159
Long-term Risk Management Liabilities	1,734	—	—	1,734	(286)	1,448
Total Liabilities	24,944	—	—	24,944	(14,337)	10,607
Total MTM Derivative Contract Net Assets (Liabilities)	$30,357	$—	$—	$30,357	$915	$31,272

APCo

Fair Value of Derivative Instruments
December 31, 2014

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$32,903	$—	$—	$32,903	$(9,111)	$23,792

Long-term Risk Management Assets	5,159	—	—	5,159	(268)	4,891
Total Assets	38,062	—	—	38,062	(9,379)	28,683
Current Risk Management Liabilities	20,161	—	—	20,161	(9,144)	11,017
Long-term Risk Management Liabilities	2,322	—	—	2,322	(265)	2,057
Total Liabilities	22,483	—	—	22,483	(9,409)	13,074
Total MTM Derivative Contract Net Assets (Liabilities)	$ 15,579	$—	$—	$ 15,579	$ 30	$ 15,609

(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 include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."

(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.

I&M

Fair Value of Derivative Instruments
June 30, 2015

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$26,147	$—	$—	$26,147	$(9,633)	$16,514
Long-term Risk Management Assets	2,219	—	—	2,219	(193)	2,026
Total Assets	28,366	—	—	28,366	(9,826)	18,540
Current Risk Management Liabilities	14,553	—	—	14,553	(10,060)	4,493
Long-term Risk Management Liabilities	1,176	—	—	1,176	(194)	982
Total Liabilities	15,729	—	—	15,729	(10,254)	5,475
Total MTM Derivative Contract Net Assets (Liabilities)	$12,637	$—	$—	$12,637	$428	$13,065

I&M

Fair Value of Derivative Instruments
December 31, 2014

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$28,545	$—	$—	$28,545	$(6,217)	$22,328
Long-term Risk Management Assets	3,499	—	—	3,499	(182)	3,317
Total Assets	32,044	—	—	32,044	(6,399)	25,645

Current Risk Management Liabilities	11,326	—	—	11,326	(6,103)	5,223
Long-term Risk Management Liabilities	1,575	—	—	1,575	(180)	1,395
Total Liabilities	12,901	—	—	12,901	(6,283)	6,618
Total MTM Derivative Contract Net Assets (Liabilities)	$19,143	$—	$—	$19,143	$(116)	$19,027

(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 include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."

(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.

OPCo

Fair Value of Derivative Instruments
June 30, 2015

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$70	$—	$—	$70	$(70)	$—
Long-term Risk Management Assets	44,056	—	—	44,056	—	44,056
Total Assets	44,126	—	—	44,126	(70)	44,056
Current Risk Management Liabilities	2,201	—	—	2,201	(191)	2,010
Long-term Risk Management Liabilities	4,573	—	—	4,573	—	4,573
Total Liabilities	6,774	—	—	6,774	(191)	6,583
Total MTM Derivative Contract Net Assets (Liabilities)	$37,352	$—	$—	$37,352	$121	$37,473

OPCo

Fair Value of Derivative Instruments
December 31, 2014

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$7,242	$—	$—	$7,242	$—	$7,242
Long-term Risk Management Assets	45,102	—	—	45,102	—	45,102
Total Assets	52,344	—	—	52,344	—	52,344

Current Risk Management Liabilities	2,045	—	—	2,045	(102	) 1,943
Long-term Risk Management Liabilities	3,013	—	—	3,013	—	3,013
Total Liabilities	5,058	—	—	5,058	(102	) 4,956
Total MTM Derivative Contract Net Assets (Liabilities)	$47,286	$—	$—	$47,286	$102	$47,388

(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 include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."

(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.

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PSO

Fair Value of Derivative Instruments
June 30, 2015

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$1,821	$—	$—	$1,821	$(90)	$1,731
Long-term Risk Management Assets	29	—	—	29	—	29
Total Assets	1,850	—	—	1,850	(90)	1,760
Current Risk Management Liabilities	334	—	—	334	(205)	129
Long-term Risk Management Liabilities	—	—	—	—	—	—
Total Liabilities	334	—	—	334	(205)	129
Total MTM Derivative Contract Net Assets (Liabilities)	$1,516	$—	$—	$1,516	$115	$1,631

PSO

Fair Value of Derivative Instruments
December 31, 2014

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$360	$—	$—	$360	$(360)	$—
Long-term Risk Management Assets	—	—	—	—	—	—
Total Assets	360	—	—	360	(360)	—

Current Risk Management Liabilities	1,332	—	—	1,332	(414)	918
Long-term Risk Management Liabilities	—	—	—	—	—	—
Total Liabilities	1,332	—	—	1,332	(414)	918
Total MTM Derivative Contract Net Assets (Liabilities)	$(972)	$—	$—	$(972)	$54	$(918)

(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 include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."

(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.

SWEPCo

Fair Value of Derivative Instruments
June 30, 2015

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$2,183	$—	$—	$2,183	$(106)	$2,077
Long-term Risk Management Assets	33	—	—	33	—	33
Total Assets	2,216	—	—	2,216	(106)	2,110
Current Risk Management Liabilities	2,763	—	—	2,763	(240)	2,523
Long-term Risk Management Liabilities	—	—	—	—	—	—
Total Liabilities	2,763	—	—	2,763	(240)	2,523
Total MTM Derivative Contract Net Assets (Liabilities)	$(547)	$—	$—	$(547)	$134	$(413)

SWEPCo

Fair Value of Derivative Instruments
December 31, 2014

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$471	$—	$—	$471	$(440)	$31
Long-term Risk Management Assets	—	—	—	—	—	—
Total Assets	471	—	—	471	(440)	31

Current Risk Management Liabilities	1,584	—	—	1,584	(502)	1,082
Long-term Risk Management Liabilities	—	—	—	—	—	—
Total Liabilities	1,584	—	—	1,584	(502)	1,082
Total MTM Derivative Contract Net Assets (Liabilities)	$(1,113)	$—	$—	$(1,113)	$62	$(1,051)

(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 include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."

(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 tables below present the Registrant Subsidiaries' activity of derivative risk management contracts for the three and six months ended June 30, 2015 and 2014:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended June 30, 2015

Location of Gain (Loss)	APCo	I&M	OPCo	PSO	SWEPCo
	(in thousands)				
Electric Generation, Transmission and Distribution Revenues	$480	$619	$35	$35	$43
Sales to AEP Affiliates	355	1,005	—	—	—
Other Operation Expense	(80)	(58)	(111)	(76)	(99)
Maintenance Expense	(133)	(55)	(114)	(79)	(84)
Purchased Electricity for Resale	11	38	—	—	—
Regulatory Assets (a)	558	328	—	954	2,111
Regulatory Liabilities (a)	26,809	8,415	(7,272)	6,242	9,350
Total Gain (Loss) on Risk Management Contracts	$28,000	$10,292	$(7,462)	$7,076	$11,321

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended June 30, 2014

Location of Gain (Loss)	APCo	I&M	OPCo	PSO	SWEPCo
	(in thousands)				
Electric Generation, Transmission and Distribution Revenues	$1,184	$1,323	$56	$63	$(79)
Sales to AEP Affiliates	—	(300)	—	300	—
Regulatory Assets (a)	—	—	—	(12)	(16)
Regulatory Liabilities (a)	13,718	8,793	6,404	(669)	(1,019)
Total Gain (Loss) on Risk Management Contracts	$14,902	$9,816	$6,460	$(318)	$(1,114)

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Six Months Ended June 30, 2015

Location of Gain (Loss)	APCo	I&M	OPCo	PSO	SWEPCo
	(in thousands)				
Electric Generation, Transmission and Distribution Revenues	$1,158	$3,241	$35	$24	$26
Sales to AEP Affiliates	355	1,005	—	—	—
Other Operation Expense	(199)	(158)	(261)	(198)	(246)
Maintenance Expense	(338)	(135)	(257)	(160)	(177)
Purchased Electricity for Resale	740	332	—	—	—
Regulatory Assets (a)	1,275	(232)	—	805	(1,422)
Regulatory Liabilities (a)	28,600	5,839	(2,599)	5,575	13,309
Total Gain (Loss) on Risk Management Contracts	$31,591	$9,892	$(3,082)	$6,046	$11,490

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Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Six Months Ended June 30, 2014

Location of Gain (Loss)	APCo	I&M	OPCo	PSO	SWEPCo
	(in thousands)				
Electric Generation, Transmission and Distribution Revenues	$6,031	$7,479	$56	$127	$(56)
Sales to AEP Affiliates	—	(521)	—	521	—
Regulatory Assets (a)	4	—	—	(10)	(13)
Regulatory Liabilities (a)	46,050	27,110	41,503	(189)	311
Total Gain on Risk Management Contracts	$52,085	$34,068	$41,559	$449	$242

(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.

The 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, management designates 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. Certain derivatives that economically hedge future commodity risk are recorded in the same expense line item on the condensed statements of income as that of the associated risk. 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."

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015, see Note 4 - Rate Matters. These auctions resulted in a range of products, including 12-month, 24-month, and 36-month periods. The delivery period for each contract is scheduled to start on the first day of June of each year, immediately following the auction. Certain affiliated Vertically Integrated Utility and Generation & Marketing segment entities participated in the auction process and were awarded tranches of OPCo's SSO load. The underlying contracts are derivatives subject to the accounting guidance for "Derivatives and Hedging" and are accounted for using MTM accounting, unless the contract has been designated as a normal purchase or normal sale. The following table represents the affiliated portion of the Registrant Subsidiaries' assets and liabilities on the condensed balance sheets resulting from these transactions:

Company	June 30, 2015 Risk Management Assets	Regulatory Liabilities and Deferred Investment Tax Credits
	(in thousands)	
APCo	$2,690	$2,690

I&M	3,137	3,137

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Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), the Registrant Subsidiaries initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets until the period the hedged item affects Net Income. The Registrant Subsidiaries 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 designated as cash flow hedges are included in Revenues or Purchased Electricity for Resale on the condensed statements of income, or in Regulatory Assets or Regulatory Liabilities on the condensed balance sheets, depending on the specific nature of the risk being hedged. During the three and six months ended June 30, 2015, the Registrant Subsidiaries did not designate power derivatives as cash flow hedges. During the three and six months ended June 30, 2014, APCo and I&M designated power derivatives as cash flow hedges.

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

The Registrant Subsidiaries reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets into Interest Expense on the condensed statements of income in those periods in which hedged interest payments occur. During the three and six months ended June 30, 2015, the Registrant Subsidiaries did not designate interest rate derivatives as cash flow hedges. During the three and six months ended June 30, 2014, I&M designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets into Depreciation and Amortization expense on the 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 and six months ended June 30, 2015 and 2014, the Registrant Subsidiaries did not designate any foreign currency derivatives as cash flow hedges.

During the three and six months ended June 30, 2015 and 2014, hedge ineffectiveness was immaterial or nonexistent for all of the hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets and the reasons for changes in cash flow hedges for the three and six months ended June 30, 2015 and 2014, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets as of June 30, 2015 and December 31, 2014 were:

Impact of Cash Flow Hedges on the Registrant Subsidiaries'
Condensed Balance Sheets
June 30, 2015

	Hedging Assets (a)		Hedging Liabilities (a)		AOCI Gain (Loss) Net of Tax	
Company	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency
	(in thousands)					
APCo	$—	$—	$—	$—	$—	$4,027
I&M	—	—	—	—	—	(13,871)
OPCo	—	—	—	—	—	4,916
PSO	—	—	—	—	—	4,563
SWEPCo	—	—	—	—	—	(9,902)

	Expected to be Reclassified to Net Income During the Next Twelve Months		
Company	Commodity	Interest Rate and Foreign Currency	Maximum Term for Exposure to Variability of Future Cash Flows
	(in thousands)		(in months)
APCo	$—	$773	0
I&M	—	(1,214)	0
OPCo	—	1,350	0
PSO	—	759	0
SWEPCo	—	(1,728)	0

Impact of Cash Flow Hedges on the Registrant Subsidiaries'
Condensed Balance Sheets
December 31, 2014

	Hedging Assets (a)		Hedging Liabilities (a)		AOCI Gain (Loss) Net of Tax	
Company	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency
	(in thousands)					
APCo	$—	$—	$—	$—	$—	$3,896
I&M	—	—	—	—	—	(14,406)
OPCo	—	—	—	—	—	5,602
PSO	—	—	—	—	—	4,943
SWEPCo	—	—	—	—	—	(11,036)

	Expected to be Reclassified to Net Income During the Next Twelve Months	
Company	Commodity	Interest Rate and Foreign Currency

	(in thousands)	
APCo	$—	$275
I&M	—	(1,090)
OPCo	—	1,372
PSO	—	759
SWEPCo	—	(1,998)

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

The actual amounts reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes.

Credit Risk

AEPSC, on behalf of the Registrant Subsidiaries, limits credit risk in their 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. AEPSC, on behalf of the Registrant Subsidiaries, uses 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 AEPSC, on behalf of the Registrant Subsidiaries, uses 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 the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's 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) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, the Registrant Subsidiaries are obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. The Registrant Subsidiaries have not experienced a downgrade below investment grade. The following tables represent the Registrant Subsidiaries exposure if credit ratings were to decline below a specified rating threshold as of June 30, 2015 and December 31, 2014:

	June 30, 2015			
Company	Fair Value of Contracts with Credit Downgrade Triggers	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post for Derivative Contracts as well as Non-Derivative Contracts Subject to the Same Master Netting Arrangement	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post Attributable to RTOs and ISOs	Amount of Collateral Attributable to Other Contracts
	(in thousands)			
APCo	$—	$—	$3,211	$987
I&M	—	—	2,178	215
OPCo	—	—	—	—
PSO	—	—	244	6,783
SWEPCo	—	—	293	210

	December 31, 2014	
		Amount of Collateral the Registrant Subsidiaries Would Have Been Required

Company	Fair Value of Contracts with Credit Downgrade Triggers	to Post for Derivative Contracts as well as Non-Derivative Contracts Subject to the Same Master Netting Arrangement	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post Attributable to RTOs and ISOs	Amount of Collateral Attributable to Other Contracts
	(in thousands)			
APCo	$—	$—	$6,339	$74
I&M	—	—	4,299	47
OPCo	—	—	—	—
PSO	—	—	693	4,111
SWEPCo	—	—	877	166

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In addition, a majority of the Registrant Subsidiaries' 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, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following tables represent: (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 posted by the Registrant Subsidiaries and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering the Registrant Subsidiaries' contractual netting arrangements as of June 30, 2015 and December 31, 2014:

	June 30, 2015		
Company	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
	(in thousands)		
APCo	$6,795	$—	$6,715
I&M	4,609	—	4,554
OPCo	—	—	—
PSO	—	—	—
SWEPCo	—	—	—

	December 31, 2014		
Company	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
	(in thousands)		
APCo	$9,043	$—	$9,012
I&M	6,134	—	6,113
OPCo	—	—	—
PSO	—	—	—
SWEPCo	—	—	—

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 and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP's Board of Directors. The AEP System's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) various 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.

For 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. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included 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 the contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A significant portion of the Level 3 instruments have been economically hedged which greatly limits potential earnings volatility.

AEP utilizes its trustee's external pricing service in its estimate of the fair value of the underlying investments held in the nuclear trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the 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, Restricted Cash for Securitized Funding and Cash and Cash Equivalents 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

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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 could be realized in a current market exchange.

The book values and fair values of Long-term Debt for the Registrant Subsidiaries as of June 30, 2015 and December 31, 2014 are summarized in the following table:

	June 30, 2015		December 31, 2014	
Company	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
APCo	$3,966,647	$4,396,429	$3,980,274	$4,711,210
I&M	2,088,913	2,264,196	2,027,397	2,255,124
OPCo	2,189,159	2,515,960	2,297,123	2,709,452
PSO	1,290,995	1,417,359	1,041,036	1,216,205
SWEPCo	2,435,478	2,600,476	2,140,437	2,402,639

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 I&M 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.

I&M maintains 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 these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. 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.

The following is a summary of nuclear trust fund investments as of June 30, 2015 and December 31, 2014:

	June 30, 2015			December 31, 2014		
	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in thousands)					
Cash and Cash Equivalents	$52,861	$—	$—	$19,966	$—	$—
Fixed Income Securities:						
United States Government	786,222	37,318	(2,613)	697,042	44,615	(5,016)
Corporate Debt	61,654	2,851	(1,115)	47,792	4,523	(1,018)
State and Local Government	70,170	992	(374)	208,553	1,206	(319)
Subtotal Fixed Income Securities	918,046	41,161	(4,102)	953,387	50,344	(6,353)
Equity Securities - Domestic	1,135,183	594,609	(78,256)	1,122,379	598,788	(79,142)
Spent Nuclear Fuel and Decommissioning Trusts	$2,106,090	$635,770	$(82,358)	$2,095,732	$649,132	$(85,495)

The following table provides the securities activity within the decommissioning and SNF trusts for the three and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)			
Proceeds from Investment Sales	$287,620	$334,834	$515,784	$482,534
Purchases of Investments	294,870	344,324	540,711	508,835
Gross Realized Gains on Investment Sales	7,657	9,077	18,810	17,218
Gross Realized Losses on Investment Sales	5,885	7,834	9,656	8,708

The adjusted cost of fixed income securities was $877 million and $903 million as of June 30, 2015 and December 31, 2014, respectively. The adjusted cost of equity securities was $540 million and $524 million as of June 30, 2015 and December 31, 2014, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of June 30, 2015 was as follows:

	Fair Value of Fixed Income Securities
	(in thousands)
Within 1 year	$140,990
1 year – 5 years	375,637
5 years – 10 years	186,505
After 10 years	214,914
Total	$918,046

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, the Registrant Subsidiaries' financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2015 and December 31, 2014. 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. Management's 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 management's valuation techniques.

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in thousands)				
Restricted Cash for Securitized Funding (a)	$15,565	$—	$—	$18	$15,583
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	176	20,754	34,210	(13,261)	41,879
Total Assets:	$15,741	$20,754	$34,210	$(13,243)	$57,462
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$197	$24,212	$374	$(14,176)	$10,607

APCo

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

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in thousands)				
Restricted Cash for Securitized Funding (a)	$15,599	$—	$—	$33	$15,632
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	206	20,197	17,654	(9,374)	28,683
Total Assets:	$15,805	$20,197	$17,654	$(9,341)	$44,315
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$227	$20,339	$1,912	$(9,404)	$13,074

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in thousands)				
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	$119	$15,428	$12,710	$(9,717)	$18,540
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (d)	41,818	—	—	11,043	52,861
Fixed Income Securities:					
United States Government	—	786,222	—	—	786,222
Corporate Debt	—	61,654	—	—	61,654
State and Local Government	—	70,170	—	—	70,170
Subtotal Fixed Income Securities	—	918,046	—	—	918,046
Equity Securities - Domestic (e)	1,135,183	—	—	—	1,135,183
Total Spent Nuclear Fuel and Decommissioning Trusts	1,177,001	918,046	—	11,043	2,106,090
Total Assets	$1,177,120	$933,474	$12,710	$1,326	$2,124,630
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$133	$14,621	$866	$(10,145)	$5,475

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I&M

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

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in thousands)				
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	$140	$15,893	$16,008	$(6,396)	$25,645
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (d)	9,418	—	—	10,548	19,966
Fixed Income Securities:					
United States Government	—	697,042	—	—	697,042
Corporate Debt	—	47,792	—	—	47,792
State and Local Government	—	208,553	—	—	208,553
Subtotal Fixed Income Securities	—	953,387	—	—	953,387
Equity Securities - Domestic (e)	1,122,379	—	—	—	1,122,379
Total Spent Nuclear Fuel and Decommissioning Trusts	1,131,797	953,387	—	10,548	2,095,732
Total Assets	$1,131,937	$969,280	$16,008	$4,152	$2,121,377
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$154	$11,440	$1,304	$(6,280)	$6,618

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in thousands)				
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	$—	$121	$42,474	$1,461	$44,056
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$—	$426	$4,817	$1,340	$6,583

OPCo

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

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in thousands)				
Restricted Cash for Securitized Funding (a)	$408	$—	$—	$28,288	$28,696
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	—	—	52,343	1	52,344
Total Assets	$408	$—	$52,343	$28,289	$81,040
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$—	$1,116	$3,941	$(101)	$4,956

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2015

Assets:	Level 1 (in thousands)	Level 2	Level 3	Other	Total
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	$2	$98	$1,750	$(90)	$1,760
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$5	$278	$51	$(205)	$129

PSO

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

Assets:	Level 1 (in thousands)	Level 2	Level 3	Other	Total
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	$—	$—	$360	$(360)	$—
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$—	$595	$737	$(414)	$918

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in thousands)				
Cash and Cash Equivalents (a)	$6,391	$—	$—	$1,626	$8,017
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	3	114	2,100	(107)	2,110
Total Assets	$6,394	$114	$2,100	$1,519	$10,127
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$6	$2,697	$61	$(241)	$2,523

SWEPCo

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

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in thousands)				
Cash and Cash Equivalents (a)	$12,660	$—	$—	$1,696	$14,356
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	—	31	439	(439)	31
Total Assets	$12,660	$31	$439	$1,257	$14,387
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$—	$684	$899	$(501)	$1,082

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 amounts primarily represent investment in money market funds.
(b) 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.”
(c) Substantially comprised of power contracts for APCo, I&M and OPCo and coal contracts for PSO and SWEPCo.
(d) Amounts in “Other” column primarily represent accrued interest receivables from financial institutions. Level 1 amounts primarily represent investments in money market funds.
(e) Amounts represent publicly traded equity securities and equity-based mutual funds.

There were no transfers between Level 1 and Level 2 during the three and six months ended June 30, 2015 and 2014.

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The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy for the Registrant Subsidiaries:

Three Months Ended June 30, 2015	APCo	I&M	OPCo	PSO	SWEPCo
	(in thousands)				
Balance as of March 31, 2015	$5,987	$5,573	$45,942	$(685)	$(1,222)
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(1,380)	(802)	638	766	4,173
Purchases, Issuances and Settlements (c)	(1,606)	(2,264)	(1,691)	(81)	(2,951)
Transfers out of Level 3 (e) (f)	1,167	792	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	29,668	8,545	(7,232)	1,699	2,039
Balance as of June 30, 2015	$33,836	$11,844	$37,657	$1,699	$2,039

Three Months Ended June 30, 2014	APCo	I&M	OPCo	PSO	SWEPCo
	(in thousands)				
Balance as of March 31, 2014	$7,401	$4,842	$3,912	$349	$442
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(4,046)	(2,554)	(4,236)	(349)	(442)
Purchases, Issuances and Settlements (c)	(32)	(35)	347	—	—
Transfers into Level 3 (d) (e)	182	124	—	—	—
Transfers out of Level 3 (e) (f)	3	2	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	14,886	10,544	9,277	(3)	(3)
Balance as of June 30, 2014	$18,394	$12,923	$9,300	$(3)	$(3)

Six Months Ended June 30, 2015	APCo	I&M	OPCo	PSO	SWEPCo
	(in thousands)				
Balance as of December 31, 2014	$15,742	$14,704	$48,402	$(377)	$(460)
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	1,230	(825)	1,548	(176)	9,187
Purchases, Issuances and Settlements (c)	(14,964)	(11,319)	(8,368)	553	(8,727)
Transfers out of Level 3 (e) (f)	1,167	792	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	30,661	8,492	(3,925)	1,699	2,039
Balance as of June 30, 2015	$33,836	$11,844	$37,657	$1,699	$2,039

Six Months Ended June 30, 2014	APCo	I&M	OPCo	PSO	SWEPCo
	(in thousands)				
Balance as of December 31, 2013	$10,562	$7,164	$2,920	$—	$—
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	29,132	18,211	30,768	—	—
Purchases, Issuances and Settlements (c)	(31,790)	(20,014)	(33,688)	—	—
Transfers into Level 3 (d) (e)	(3,643)	(2,471)	—	—	—
Transfers out of Level 3 (e) (f)	(2)	(2)	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	14,135	10,035	9,300	(3)	(3)
Balance as of June 30, 2014	$18,394	$12,923	$9,300	$(3)	$(3)

(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 Level 3 positions for the Registrant Subsidiaries as of June 30, 2015 and December 31, 2014:

Significant Unobservable Inputs
June 30, 2015
APCo

	Fair Value		Valuation	Significant Unobservable	Forward Price Range		Weighted
	Assets	Liabilities	Technique	Input (a)	Low	High	Average
	(in thousands)						
Energy Contracts	$10,570	$183	Discounted Cash Flow	Forward Market Price	$15.36	$56.30	$35.88
FTRs	23,640	191	Discounted Cash Flow	Forward Market Price	(6.16)	9.87	1.57
Total	$34,210	$374					

Significant Unobservable Inputs
December 31, 2014
APCo

	Fair Value		Valuation	Significant Unobservable	Forward Price Range		Weighted
	Assets	Liabilities	Technique	Input (a)	Low	High	Average
	(in thousands)						
Energy Contracts	$5,801	$1,799	Discounted Cash Flow	Forward Market Price	$13.43	$123.02	$52.47
FTRs	11,853	113	Discounted Cash Flow	Forward Market Price	(14.63)	20.02	1.01

Total	$17,654	$1,912

Significant Unobservable Inputs
June 30, 2015
I&M

	Fair Value		Valuation	Significant	Forward Price Range		Weighted
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Average
	(in thousands)						
Energy Contracts	$9,184	$116	Discounted Cash Flow	Forward Market Price	$15.36	$56.30	$35.88
FTRs	3,526	750	Discounted Cash Flow	Forward Market Price	(6.16)	9.87	1.57
Total	$12,710	$866					

Significant Unobservable Inputs
December 31, 2014
I&M

	Fair Value		Valuation	Significant	Forward Price Range		Weighted
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Average
	(in thousands)						
Energy Contracts	$6,375	$1,219	Discounted Cash Flow	Forward Market Price	$13.43	$123.02	$52.47
FTRs	9,633	85	Discounted Cash Flow	Forward Market Price	(14.63)	20.02	1.01
Total	$16,008	$1,304					

Significant Unobservable Inputs
June 30, 2015
OPCo

	Fair Value		Valuation	Significant	Forward Price Range		Weighted
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Average
	(in thousands)						
Energy Contracts	$42,474	$4,817	Discounted Cash Flow	Forward Market Price	$42.89	$163.52	$91.51

Significant Unobservable Inputs
December 31, 2014
OPCo

	Fair Value		Valuation	Significant	Forward Price Range		Weighted
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Average
	(in thousands)						
Energy Contracts	$45,101	$3,941	Discounted Cash Flow	Forward Market Price	$48.25	$159.92	$84.04
FTRs	7,242	—	Discounted Cash Flow	Forward Market Price	(14.63)	20.02	1.01
	$52,343	$3,941					

Significant Unobservable Inputs
June 30, 2015
PSO

	Fair Value		Valuation	Significant	Forward Price Range		Weighted
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Average
	(in thousands)						
FTRs	$1,750	$51	Discounted Cash Flow	Forward Market Price	$(6.16)	$9.87	$1.57

Significant Unobservable Inputs
December 31, 2014
PSO

	Fair Value		Valuation	Significant	Forward Price Range		Weighted
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Average
	(in thousands)						
FTRs	$360	$737	Discounted Cash Flow	Forward Market Price	$(14.63)	$20.02	$1.01

Significant Unobservable Inputs
June 30, 2015
SWEPCo

	Fair Value		Valuation	Significant	Forward Price Range		Weighted
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Average
	(in thousands)						
FTRs	$2,100	$61	Discounted Cash Flow	Forward Market Price	$(6.16)	$9.87	$1.57

Significant Unobservable Inputs
December 31, 2014
SWEPCo

	Fair Value		Valuation	Significant	Forward Price Range		Weighted
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Average
	(in thousands)						
FTRs	$439	$899	Discounted Cash Flow	Forward Market Price	$(14.63)	$20.02	$1.01

(a) Represents market prices in dollars per MWh.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs for the Registrant Subsidiaries as of June 30, 2015:

Sensitivity of Fair Value Measurements
June 30, 2015

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement

Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

10. INCOME TAXES

AEP System Tax Allocation Agreement

The Registrant Subsidiaries join in the filing of a consolidated federal income tax return with their affiliates in the AEP System. 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 its 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 Registrant Subsidiaries are no longer subject to U.S. federal examination for years before 2011. The IRS examination of years 2011, 2012 and 2013 started in April 2014. Although the outcome of tax audits is uncertain, in management’s opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, the Registrant Subsidiaries accrue interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact the Registrant Subsidiaries' net income.

The Registrant Subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns and the Registrant Subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes 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 the Registrant Subsidiaries' net income. The Registrant Subsidiaries are no longer subject to state or local income tax examinations by tax authorities for years before 2009.

State Tax Legislation

House Bill 32 was passed by the state of Texas in June 2015 permanently reducing the Texas income/franchise tax rate from 0.95% to 0.75% effective January 1, 2016, applicable to reports originally due on or after the effective date. The Texas income/franchise tax rate had been scheduled to return to 1% in 2016. The enacted provision did not materially impact the Registrant Subsidiaries' net income, cash flows or financial condition.

11. FINANCING ACTIVITIES

Long-term Debt

Long-term debt and other securities issued, retired and principal payments made during the first six months of 2015 are shown in the tables below:

Company	Type of Debt	Principal Amount (a)	Interest Rate	Due Date
Issuances:		(in thousands)	(%)	
APCo	Pollution Control Bonds	$86,000	1.90	2019
APCo	Senior Unsecured Notes	350,000	4.45	2045
APCo	Senior Unsecured Notes	300,000	3.40	2025
I&M	Notes Payable	111,300	Variable	2019
I&M	Other Long-term Debt	100,000	Variable	2018
PSO	Senior Unsecured Notes	125,000	3.17	2025
PSO	Senior Unsecured Notes	125,000	4.09	2045
SWEPCo	Pollution Control Bonds	53,500	1.60	2019
SWEPCo	Senior Unsecured Notes	400,000	3.90	2045

(a) Amounts indicated on the statements of cash flows are net of issuance costs and premium or discount and will not tie to the issuance amounts.

Company	Type of Debt	Principal Amount Paid	Interest Rate	Due Date
Retirements and Principal Payments:		(in thousands)	(%)	
APCo	Land Note	$18	13.718	2026
APCo	Notes Payable - Affiliated	86,000	3.125	2015
APCo	Securitization Bonds	11,037	2.008	2024
APCo	Senior Unsecured Notes	350,000	7.95	2020
APCo	Senior Unsecured Notes	300,000	3.40	2015
I&M	Notes Payable	18,600	Variable	2016
I&M	Notes Payable	13,659	Variable	2017
I&M	Notes Payable	16,501	Variable	2019
I&M	Notes Payable	5,834	Variable	2019
I&M	Notes Payable	844	Variable	2016
I&M	Notes Payable	585	2.12	2016
I&M	Other Long-term Debt	93,500	Variable	2015
I&M	Other Long-term Debt	554	6.00	2025
OPCo	Other Long-term Debt	38	1.149	2028
OPCo	Pollution Control Bonds	86,000	3.125	2015
OPCo	Securitization Bonds	22,200	0.958	2018
PSO	Other Long-term Debt	212	3.00	2027
SWEPCo	Notes Payable	1,625	4.58	2032
SWEPCo	Pollution Control Bonds	53,500	3.25	2015
SWEPCo	Senior Unsecured Notes	100,000	5.375	2015

In July 2015, OPCo retired $23 million of Securitization Bonds.

In July 2015, SWEPCo retired $150 million of 4.9% Senior Unsecured Notes due in 2015.

As of June 30, 2015, trustees held on behalf of I&M and OPCo, $40 million and $345 million, respectively, of their reacquired Pollution Control Bonds.

Dividend Restrictions

The Registrant Subsidiaries pay dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the Registrant Subsidiaries to transfer funds to Parent in the form of dividends.

Federal Power Act

The Federal Power Act prohibits each of the Registrant 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 Registrant Subsidiaries to pay dividends out of retained earnings.

Additionally, the Federal Power Act creates a reserve on earnings attributable to hydroelectric generation plants. Because of their respective ownership of such plants, this reserve applies to APCo and I&M.

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, APCo, I&M, PSO and SWEPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of June 30, 2015 and December 31, 2014 are included in Advances to Affiliates and Advances from Affiliates, respectively, on each of the Registrant Subsidiaries' condensed balance sheets. The Utility Money Pool participants' money pool activity and their corresponding authorized borrowing limits for the six months ended June 30, 2015 are described in the following table:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings from) the Utility Money Pool as of June 30, 2015	Authorized Short-term Borrowing Limit
	(in thousands)					
APCo	$82,417	$694,785	$58,723	$133,887	$(33,703)	$600,000
I&M	200,032	13,515	141,520	13,501	(127,154)	500,000
OPCo	—	367,472	—	273,487	187,812	400,000
PSO	165,947	95,472	113,117	51,855	64,212	300,000
SWEPCo	112,481	299,932	52,596	170,502	179,709	350,000

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

	Six Months Ended June 30,	
	2015	2014
Maximum Interest Rate	0.59 %	0.33 %
Minimum Interest Rate	0.39 %	0.24 %

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the six months ended June 30, 2015 and 2014 are summarized for all Registrant Subsidiaries in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Six Months Ended June 30,		Average Interest Rate for Funds Loaned to the Utility Money Pool for Six Months Ended June 30,	
Company	2015	2014	2015	2014
APCo	0.45 %	0.26 %	0.46 %	0.29 %
I&M	0.47 %	0.26 %	0.47 %	0.30 %
OPCo	— %	0.27 %	0.47 %	0.29 %
PSO	0.49 %	0.28 %	0.47 %	— %
SWEPCo	0.46 %	0.28 %	0.49 %	— %

Credit Facilities

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

Sale of Receivables – AEP Credit

Under a sale of receivables arrangement, the Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit’s financing costs, administrative costs and uncollectible accounts experience for each Registrant Subsidiary’s receivables. APCo does not have regulatory authority to sell its West Virginia accounts receivable. The costs of customer accounts receivable sold are reported in Other Operation expense on the Registrant Subsidiaries’ condensed statements of income. The Registrant Subsidiaries manage and service their customer accounts receivable sold.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement was increased in June 2014 from $700 million and expires in June 2017.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement for each Registrant Subsidiary as of June 30, 2015 and December 31, 2014 was as follows:

Company	June 30, 2015	December 31, 2014
	(in thousands)	
APCo	$139,005	$159,823
I&M	145,633	137,459
OPCo	366,098	365,834
PSO	131,940	112,905
SWEPCo	163,994	148,668

The fees paid by the Registrant Subsidiaries to AEP Credit for customer accounts receivable sold were:

	Three Months Ended June 30,		Six Months Ended June 30,	
Company	2015	2014	2015	2014
	(in thousands)			
APCo	$1,573	$2,037	$4,027	$4,460
I&M	2,063	1,785	4,420	3,825
OPCo	6,668	6,647	14,683	14,145
PSO	1,324	1,349	2,746	2,672
SWEPCo	1,625	1,579	3,347	3,145

The Registrant Subsidiaries' proceeds on the sale of receivables to AEP Credit were:

	Three Months Ended June 30,		Six Months Ended June 30,	
Company	2015	2014	2015	2014
	(in thousands)			
APCo	$330,593	$345,963	$760,217	$783,159
I&M	371,058	353,030	790,619	760,180
OPCo	563,381	626,025	1,278,365	1,312,652
PSO	311,885	325,536	614,386	615,753
SWEPCo	381,100	420,909	754,267	811,497

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 they are the primary beneficiary of a VIE, management considers for each Registrant Subsidiary factors such as equity at risk, the amount of the VIE's variability the Registrant Subsidiary absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. Management believes that significant assumptions and judgments were applied consistently. In addition, the Registrant Subsidiaries have not provided financial or other support to any VIE that was not previously contractually required.

SWEPCo is the primary beneficiary of Sabine. I&M is the primary beneficiary of DCC Fuel. OPCo is the primary beneficiary of Ohio Phase-in-Recovery Funding. APCo is the primary beneficiary of Appalachian Consumer Rate Relief Funding. In addition, the Registrant Subsidiaries have not provided material financial or other support to any of these entities that was not previously contractually required. SWEPCo holds a significant variable interest in DHLC. Each of the Registrant Subsidiaries hold a significant variable interest in AEPSC. I&M holds a significant variable interest in AEGCo.

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 June 30, 2015 and 2014 were $41 million and $41 million, respectively, and for the six months ended June 30, 2015 and 2014 were $83 million and $80 million, respectively. See the table below for the classification of Sabine's assets and liabilities on SWEPCo's condensed balance sheets.

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
VARIABLE INTEREST ENTITIES
June 30, 2015 and December 31, 2014
(in thousands)

	Sabine	
ASSETS	2015	2014
Current Assets	$57,592	$67,981
Net Property, Plant and Equipment	142,265	145,491
Other Noncurrent Assets	59,717	51,578
Total Assets	$259,574	$265,050

LIABILITIES AND EQUITY

Current Liabilities	$28,122	$36,286
Noncurrent Liabilities	231,155	228,349
Equity	297	415
Total Liabilities and Equity	$259,574	$265,050

I&M has nuclear fuel lease agreements with DCC Fuel, which 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 DCC Fuel 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 June 30, 2015 and 2014 were $34 million and $32 million, respectively, and for the six months ended June 30, 2015 and 2014 were $57 million and $56 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 I&M's 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. See the table below for the classification of DCC Fuel's assets and liabilities on I&M's condensed balance sheets.

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

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
VARIABLE INTEREST ENTITIES
June 30, 2015 and December 31, 2014
(in thousands)

	DCC Fuel	
ASSETS	2015	2014
Current Assets	$114,522	$97,361
Net Property, Plant and Equipment	219,786	158,121
Other Noncurrent Assets	117,702	79,705
Total Assets	$452,010	$335,187
LIABILITIES AND EQUITY		
Current Liabilities	$109,491	$86,026
Noncurrent Liabilities	342,519	249,161
Total Liabilities and Equity	$452,010	$335,187

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 $210 million and $232 million as of June 30, 2015 and December 31, 2014, respectively, and are included in current and long-term debt on the condensed balance sheets. Ohio Phase-in-Recovery Funding has securitized assets of $98 million and $110 million as of June 30, 2015 and December 31, 2014, respectively, which are presented separately on the face of the condensed balance sheets. 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 OPCo's condensed balance sheets.

The balances below represent the assets and liabilities of Ohio Phase-in-Recovery Funding that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

OHIO POWER COMPANY AND SUBSIDIARIES
VARIABLE INTEREST ENTITIES
June 30, 2015 and December 31, 2014
(in thousands)

	Ohio Phase-In Recovery Funding	
ASSETS	2015	2014
Current Assets	$32,778	$32,676
Other Noncurrent Assets (a)	186,609	209,922
Total Assets	$219,387	$242,598
LIABILITIES AND EQUITY		
Current Liabilities	$47,539	$47,099
Noncurrent Liabilities	170,511	194,162
Equity	1,337	1,337
Total Liabilities and Equity	$219,387	$242,598

(a) Includes an intercompany item eliminated in consolidation as of June 30, 2015 and December 31, 2014 of $87 million and $97 million, respectively.

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 $357 million and $368 million as of June 30, 2015 and December 31, 2014, respectively, and are included in current and long term debt on the condensed balance sheets. Appalachian Consumer Rate Relief Funding has securitized assets of $339 million and $350 million as of June 30, 2015 and December 31, 2014, respectively, which are presented separately on the face of the condensed balance sheets. 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 APCo’s condensed balance sheets.

The balances below represent the assets and liabilities of Appalachian Consumer Rate Relief Funding that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
VARIABLE INTEREST ENTITIES
June 30, 2015 and December 31, 2014
(in thousands)

	Appalachian Consumer Rate Relief Funding	
ASSETS	2015	2014
Current Assets	$19,145	$18,099
Other Noncurrent Assets (a)	346,809	358,264
Total Assets	$365,954	$376,363
LIABILITIES AND EQUITY		
Current Liabilities	$26,912	$26,809
Noncurrent Liabilities	337,316	347,652
Equity	1,726	1,902
Total Liabilities and Equity	$365,954	$376,363

(a) Includes an intercompany item eliminated in consolidation as of June 30, 2015 and December 31, 2014 of $4 million and $4 million, respectively.

DHLC is a mining operator which 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 June 30, 2015 and 2014 were $15 million and $6 million, respectively, and for the six months ended June 30, 2015 and 2014 were $29 million and $8 million, respectively. SWEPCo is not required to consolidate DHLC as it is not the primary beneficiary, although SWEPCo holds a significant variable interest in DHLC. SWEPCo's equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on SWEPCo's condensed balance sheets.

SWEPCo's investment in DHLC was:

	June 30, 2015			December 31, 2014		
	As Reported on the Balance Sheet	Maximum Exposure		As Reported on the Balance Sheet	Maximum Exposure	
	(in thousands)					
Capital Contribution from SWEPCo	$7,643	$7,643		$7,643	$7,643	
Retained Earnings	5,540	5,540		3,819	3,819	
SWEPCo's Guarantee of Debt	—	106,408	(a)	—	104,334	(a)
Total Investment in DHLC	$13,183	$119,591		$11,462	$115,796	

(a) Includes affiliate advances due to Parent related to participation in the Utility Money Pool of $56 million and $56 million in 2015 and 2014, respectively.

AEPSC provides certain managerial and professional services to AEP’s subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC’s cost. AEP subsidiaries have not provided financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP.

Total AEPSC billings to the Registrant Subsidiaries were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
Company	2015	2014	2015	2014
	(in thousands)			
APCo	$52,722	$53,959	$100,970	$104,096
I&M	31,134	30,103	64,636	62,073
OPCo	40,907	40,441	80,137	79,490
PSO	24,442	22,889	47,966	47,329
SWEPCo	31,900	32,718	63,414	65,741

The carrying amount and classification of variable interest in AEPSC's accounts payable are as follows:

	June 30, 2015		December 31, 2014	
Company	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in thousands)			
APCo	$19,141	$19,141	$30,692	$30,692
I&M	11,173	11,173	22,480	22,480
OPCo	15,423	15,423	24,695	24,695
PSO	9,017	9,017	15,338	15,338
SWEPCo	12,114	12,114	20,772	20,772

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1, leases a 50% interest in Rockport Plant, Unit 2 and owns 100% of the Lawrenceburg Generating Station. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEGCo has a Unit Power Agreement associated with the Lawrenceburg Generating Station which was assigned by OPCo to AGR effective January 1, 2014. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. I&M is considered to have a significant interest in AEGCo due to these transactions. I&M is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. In the event AEGCo would require financing or other support outside the billings to I&M and KPCo, this financing would be provided by AEP. For additional information regarding AEGCo's lease, see "Rockport Lease" section of Note 13 in the 2014 Annual Report.

Total billings from AEGCo were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
Company	2015	2014	2015	2014
	(in thousands)			
I&M	$59,993	$65,190	$114,958	$135,612

The carrying amount and classification of variable interest in AEGCo's accounts payable are as follows:

	June 30, 2015		December 31, 2014	
Company	As Reported on the	Maximum	As Reported on the	Maximum

	Balance Sheet	Exposure	Balance Sheet	Exposure
	(in thousands)			
I&M	$21,084	$21,084	$20,031	$20,031

13. PROPERTY, PLANT AND EQUIPMENT

Asset Retirement Obligations (ARO)

The Registrant Subsidiaries record ARO in accordance with the accounting guidance for “Asset Retirement and Environmental Obligations” for the retirement of certain ash disposal facilities, closure and monitoring of underground carbon storage facilities at Mountaineer Plant and coal mining facilities, as well as asbestos removal. I&M records ARO for the decommissioning of the Cook Plant. The Registrant Subsidiaries have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property’s use. The retirement obligation is not estimable for such easements since the Registrant Subsidiaries plan to use their facilities indefinitely. The retirement obligation would only be recognized if and when the Registrant Subsidiaries abandon or cease the use of specific easements, which is not expected.

As of June 30, 2015 and December 31, 2014, I&M's ARO liability for nuclear decommissioning of the Cook Plant was $1.3 billion and $1.3 billion, respectively. These liabilities are reflected in Asset Retirement Obligations on I&M's condensed balance sheets. As of June 30, 2015 and December 31, 2014, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $1.8 billion and $1.8 billion, respectively. These assets are included in Spent Nuclear Fuel and Decommissioning Trusts on I&M's condensed balance sheets.

The Registrant Subsidiaries recorded an increase in asset retirement obligations in the second quarter of 2015, partially related to the final Coal Combustion Residual Rule, which was published in the Federal Register in April 2015. The Federal EPA now regulates the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and also FGD gypsum generated at some coal-fired plants. The Federal EPA regulates CCR as a non-hazardous solid waste and established minimum federal solid waste management standards. Noncash increases related to the CCR Rule are recorded as Property, Plant and Equipment.

The following is a reconciliation of the 2015 and 2014 aggregate carrying amounts of ARO by Registrant Subsidiary:

Company	ARO as of December 31, 2014	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of June 30, 2015
	(in thousands)					
APCo (a)(d)	$148,377	$4,122	$—	$(10,503)	$13,962	$155,958
I&M (a)(b)(d)	1,342,549	31,731	—	(1,222)	5,639	1,378,697
OPCo (d)(e)	1,361	41	—	(8)	—	1,394
PSO (a)(d)	38,020	1,214	5,336	(115)	1,916	46,371
SWEPCo (a)(c)(d)	94,394	2,725	12,191	(2,189)	6,348	113,469

(a) Includes ARO related to ash disposal facilities.
(b) Includes ARO related to nuclear decommissioning costs for the Cook Plant of $1.3 billion and $1.3 billion as of June 30, 2015 and December 31, 2014.
(c) Includes ARO related to Sabine and DHLC.
(d) Includes ARO related to asbestos removal.
(e) Not impacted by the CCR rule.

14. DISPOSITION PLANT SEVERANCE

Management retired several generation plants or units of plants during 2015. These plant closures resulted in involuntary severances. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

The Registrant Subsidiaries' disposition plant severance activity for the six months ended June 30, 2015 is described in the following table:

Company	Balance as of December 31, 2014	Expense Allocation from AEPSC	Incurred by Registrant Subsidiaries	Settled	Adjustments	Remaining Balance as of June 30, 2015
	(in thousands)					
APCo	$9,304	$(5)	$817	$(4,478) (a)	$(129)	$5,509
I&M	8,023	(3)	363	(3,459)	—	4,924
PSO	134	(3)	416	(116)	—	431
SWEPCo	84	(4)	—	(79)	—	1

(a) Settled includes amounts received from affiliates for expenses related to joint plant.

The Registrant Subsidiaries recorded charges to Other Operation expense in 2014 primarily related to employees at the disposition plants. The total amount incurred in 2014 by Registrant Subsidiary was as follows:

Company	Total Cost Incurred
	(in thousands)
APCo	$7,112
I&M	8,185
OPCo	80
PSO	288
SWEPCo	289

These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the condensed statements of income. The remaining liability is included in Other Current Liabilities on the condensed balance sheets. The Registrant Subsidiaries incurred additional charges during the second quarter of 2015 as severance plans were finalized after the plants were retired. Management does not expect additional severance costs to be incurred related to this initiative.

COMBINED MANAGEMENT’S NARRATIVE DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the Registrant Subsidiaries’ management’s discussion and analysis. The information in this section completes the information necessary for management’s discussion and analysis of financial condition and net income and is meant to be read with (a) Management’s Narrative Discussion and Analysis of Results of Operations, (b) financial statements, (c) footnotes and (d) the schedules of each individual registrant. The Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries section of the 2014 Annual Report should also be read in conjunction with this report.

EXECUTIVE OVERVIEW

Customer Demand

AEP's weather-normalized retail sales volumes for the second quarter of 2015 increased by 0.9% from the second quarter of 2014. Second quarter 2015 industrial sales increased 0.6% compared to the second quarter of 2014 primarily due to increased sales to customers in oil and gas related sectors. Weather-normalized commercial and residential sales increased 1.9% and 0.3% in the second quarter of 2015, respectively, from the second quarter of 2014.
AEP's weather-normalized retail sales volumes for the six months ended June 30, 2015 decreased 0.3% compared to the six months ended June 30, 2014. Industrial sales volumes increased 0.9% compared to 2014, while weather-normalized commercial sales increased by 0.7%. Weather-normalized residential sales decreased 2.2% in comparison to the first six months of 2014.

ENVIRONMENTAL ISSUES

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

The Registrant Subsidiaries 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 I&M’s nuclear units. AEP, along with various industry groups, affected states and other parties have challenged some of the Federal EPA requirements in court. Management is 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. Management believes that further analysis and better coordination of these environmental requirements would facilitate planning and lower overall compliance costs while achieving the same environmental goals.

See a complete discussion of these matters in the “Environmental Issues” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” in the 2014 Annual Report. Management 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 the costs of environmental compliance are not recovered, 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. Management continues to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of June 30, 2015, the AEP System had a total generating capacity of approximately 32,100 MWs, of which approximately 18,200 MWs are coal-fired. Management continues to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on the generating facilities. For the Registrant Subsidiaries, management's current ranges of estimates of environmental investments to comply with these requirements are listed below:

	Through 2020	
	Estimated Environmental Investment	
Company	Low	High
	(in millions)	
APCo	$310	$360
I&M	370	430
PSO	270	310
SWEPCo	880	950
Total	$1,830	$2,050

For APCo, the projected environmental investment above includes the conversion of 470 MWs of coal generation to natural gas capacity. If natural gas conversion is not completed, the units could be closed 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 for each Registrant Subsidiary will also change based on: (a) the states' implementation of these regulatory programs, including the potential for state implementation plans (SIPs) or federal implementation plans (FIPs) that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on the units, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity and (g) other factors.

In May 2015, management retired the following plants or units of plants:

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	600
I&M	Tanners Creek Plant	995
Total		2,565

As of June 30, 2015, the book value of the regulated plants in the table above was $492 million. Of this amount, $348 million has been approved for recovery while $144 million is pending regulatory approval.

Subject to the factors listed above and based upon continuing evaluation, management intends to retire the following units of plants during 2016:

Company	Plant Name and Unit	Generating Capacity (in MWs)
PSO	Northeastern Station, Unit 4	470
SWEPCo	Welsh Plant, Unit 2	528
Total		998

As of June 30, 2015, the net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of the regulated plants in the table above was $178 million. Volatility in fuel prices, pending environmental rules and other market factors could also have an adverse impact on the accounting evaluation of the recoverability of the net book values of coal-fired units. For Northeastern Station, Unit 4 and Welsh Plant, Unit 2, management is seeking regulatory recovery of remaining net book values.

To the extent existing generation assets are not recoverable, it could materially reduce future net income and cash flows and impact financial condition.

Clean Air Act Requirements

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

The Federal EPA issued the Clean Air Interstate Rule (CAIR) in 2005 requiring specific reductions in SO_2 and NO_x emissions from power plants. The Federal EPA issued the Cross-State Air Pollution Rule (CSAPR) in August 2011 to replace CAIR. The CSAPR was challenged in the courts. In 2012, a panel of the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing CAIR until a replacement rule is finalized. That decision was appealed to the U.S. Supreme Court, which reversed the decision and remanded the case to the U.S. Court of Appeals for the District of Columbia Circuit. The U.S. Court of Appeals for the District of Columbia Circuit ordered CSAPR to take effect on January 1, 2015 while the remand proceeding was still pending. All of the states in which the Registrant Subsidiaries' power plants are located are covered by CSAPR. See "Cross-State Air Pollution Rule (CSAPR)" section below.

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

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's requirement that certain facilities install best available retrofit technology (BART) will address regional haze in federal parks and other protected areas. BART requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through SIPs or, if SIPs are not adequate or are not developed on schedule, through FIPs. The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas. In March 2012, the Federal EPA disapproved certain portions of the Arkansas regional haze SIP. In April 2015, the Federal EPA published a proposed FIP to replace the disapproved portions, including revised BART determinations for the Flint Creek Plant that are consistent with the environmental controls currently under construction. In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the CSAPR trading programs to use those programs in place of source-specific BART for SO_2 and NO_x emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. This rule is being challenged in the U.S. Court of

Appeals for the District of Columbia Circuit. In July 2015, management will submit comments to the proposed Arkansas FIP and participate in comments filed by industry associations of which the AEP System is a member. Management supports compliance with CSAPR programs as satisfaction of the BART requirements.

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

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for PM, SO_2 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 facilities as a result of those evaluations. Management cannot currently predict the nature, stringency or timing of those requirements.

Notable developments in significant CAA regulatory requirements affecting the Registrant Subsidiaries' operations are discussed in the following sections.

Cross-State Air Pollution Rule (CSAPR)

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

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit. In 2012, the court issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing CAIR until a replacement rule is finalized. The majority determined that the CAA does not allow the Federal EPA to “overcontrol” emissions in an upwind state and that the Federal EPA exceeded its statutory authority by failing to allow states an opportunity to develop their own implementation plans before issuing a FIP. The petition for review filed by the Federal EPA and other parties in the U.S. Supreme Court was granted in June 2013. In April 2014, the U.S. Supreme Court issued a decision reversing in part the decision of the U.S. Court of Appeals for the District of Columbia Circuit and remanding the case for further proceedings consistent with the opinion. The Federal EPA filed a motion to lift the stay and allow Phase I of CSAPR to take effect on January 1, 2015 and Phase II to take effect on January 1, 2017. The court granted the Federal EPA's motion. The parties have filed briefs, presented oral arguments and the case remains pending. Separate appeals of the Error Corrections Rule and the further revisions were filed but no briefing schedules have been established. Management 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 units burning coal on a 30-day rolling average basis for mercury, PM (as a surrogate for particles of nonmercury metals) and hydrogen chloride (as a surrogate for acid gases). 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 was required within three years. The final rule contains a slightly less stringent PM limit for existing sources than the original proposal and the revised rule provides alternative work practice standards for operators during start-up and shut down periods. Management has obtained a one-year administrative extension at several units to facilitate the installation of controls or to avoid a serious reliability problem. In addition, the Federal EPA issued an enforcement policy describing the circumstances under which an administrative consent order might be issued to provide a fifth year for the installation of controls or completion of reliability upgrades. Management remains concerned about the availability of compliance extensions, the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines and the lack of coordination among the Mercury and Air Toxics Standards (MATS) schedule and other environmental requirements.

Petitions for administrative reconsideration and judicial review of the final rule were filed. In 2012, the Federal EPA published a notice announcing that it would accept comments on its reconsideration of certain issues related to the new source standards, including clarification of the requirements that apply during periods of start-up and shut down, measurement issues and the application of variability factors that may have an impact on the level of the standards. The Federal EPA issued revisions to the new source standards consistent with the proposed rule, except the start-up and shut down provisions in March 2013. A final rule on reconsideration was issued in 2014 and a proposed rule containing technical corrections was issued in early 2015. In April 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the April 2012 final rule. Industry trade groups and several states filed petitions for further review in the U.S. Supreme Court and the court granted those petitions in November 2014.

In June 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit and remanded the MATS rule for further proceedings consistent with its decision that the Federal EPA was unreasonable in refusing to consider costs in its determination whether to regulate emissions of HAPs from power plants. The case will be remanded to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings consistent with the U.S. Supreme Court's decision. Management will continue to evaluate the impact of this decision and until further action by the U.S. Court of Appeals for the District of Columbia Circuit, the rule remains in place.

Climate Change, CO_2 Regulation and Energy Policy

National public policy makers and regulators in the 10 states the Registrant Subsidiaries serve have diverse views on climate change, carbon regulation and energy policy. Management is currently focused on responding to these emerging views with prudent actions across a range of plausible scenarios and outcomes. Management is an active participant in both state and federal policy development to assure that any proposed new requirements are feasible and the economies of the states served are not placed at a competitive disadvantage.

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

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

January 2014 and the comment period has closed.

The Federal EPA was also directed to develop and issue a separate proposal regulating carbon emissions from modified and reconstructed electric generating units (EGUs) and to issue guidelines for existing EGUs before June 2014, to finalize those standards by June 2015 and to require states to submit plans implementing the guidelines no later than June 2016. The Federal EPA issued guidelines for the development of standards for existing sources in June 2014.

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

In 2012, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision upholding, in all material respects, the Federal EPA’s endangerment finding, its regulatory program for CO_2 emissions from new motor vehicles and its plan to phase in regulation of CO_2 emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. In June 2014, the U.S. Supreme Court determined that the Federal EPA was not compelled to regulate CO_2 emissions from stationary sources under the Title V or PSD programs as a result of its adoption of the motor vehicle standards, but that sources otherwise required to obtain a PSD permit may be required to perform a Best Available Control Technology (BACT) analysis for CO_2 emissions if they exceed a reasonable level. The Federal EPA removed those provisions of the final rule from the Code of Federal Regulations that were inconsistent with the U.S. Supreme Court’s decision but continues to apply a 75,000 ton per year threshold to trigger the need for a BACT analysis. Petitions were filed with the U.S. Court of Appeals for the District of Columbia Circuit seeking to amend the judgment in the case to require Federal EPA to establish a reasonable minimum level. Those petitions are pending.

Federal and state legislation or regulations that mandate limits on the emission of CO_2 could result in significant increases in capital expenditures and operating costs, which in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force the Registrant Subsidiaries to close some coal-fired facilities and could lead to possible impairment of assets.

Coal Combustion Residual Rule

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

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

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

The final rule was published in the Federal Register in April 2015 and becomes effective six months after publication. Management recorded a $45 million increase in asset retirement obligations in the second quarter of 2015 primarily due to the publication of the final rule. Given the future effective date of the rule and the schedule for implementation, management will continue to evaluate the rule's impact on operations.

Clean Water Act (CWA) Regulations

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

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

In April 2014, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a proposed rule to clarify the scope of the regulatory definition of “waters of the United States” in light of recent U.S. Supreme Court cases and published the proposed rule in the Federal Register. The CWA provides for federal jurisdiction over “navigable waters” defined as “the waters of the United States.” This proposed jurisdictional definition applied 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. Management submitted detailed comments to the Federal EPA in November 2014 and also participated in comments filed by various organizations of which the AEP System is a member. In June 2015, the Federal EPA published the final rule that included a few changes from the proposal. The effective date of the rule is 60 days following publication. The final definition continues to recognize traditional navigable waters of the U.S. as jurisdictional as well as certain exclusions. The rule also contains a number of new specific definitions and criteria for determining whether certain other waters are jurisdictional because of a “significant nexus." Management agrees that clarity and efficiency in the permitting process is needed. Management is concerned that the rule introduces new concepts and could subject more of the operations to CWA jurisdiction, thereby increasing the time and complexity of permitting. Management anticipates that the final rule will be challenged in the courts.

ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncements Adopted During the First Quarter of 2015

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

Pronouncements Effective in the Future

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

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

The FASB issued ASU 2015-03 “Simplifying the Presentation of Debt Issuance Costs” to simplify the presentation of debt issuance costs on the balance sheets. Under the new standard, debt issuance costs related to a recognized debt liability will be presented on the balance sheets as a direct deduction from the carrying amount of that debt liability, consistent with discounts. The Registrant Subsidiaries include debt issuance costs in Deferred Charges and Other Noncurrent Assets on the condensed balance sheets. Debt issuance costs represent less than 1% of total long-term debt. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. Management intends to early adopt ASU 2015-03 for the 2015 Form 10-K.

The FASB issued ASU 2015-05 “Customer's Accounting for Fees Paid in a Cloud Computing Arrangement” to provide guidance to customers about whether a cloud computing arrangement includes a software license. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted.

Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2015-05 effective January 1, 2016.

The FASB issued ASU 2015-11 “Simplifying the Measurement of Inventory” to simplify the guidance on the subsequent measurement of inventory, excluding inventory measured using last-in, first out or the retail inventory method. Under the new standard, inventory should be at the lower of cost and net realizable value. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016 with early adoption permitted. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2015-11 effective January 1, 2017.

Future Accounting Changes

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

CONTROLS AND PROCEDURES

During the second quarter of 2015, management, including the principal executive officer and principal financial officer of each of AEP, APCo, I&M, OPCo, PSO and SWEPCo (collectively, the Registrants), evaluated the Registrants’ disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants’ management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of June 30, 2015, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

There was no change in the Registrants’ internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the second quarter of 2015 that materially affected, or is reasonably likely to materially affect, the Registrants’ internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1.   Legal Proceedings

For a discussion of material legal proceedings, see “Commitments, Guarantees and Contingencies,” of Note 5 incorporated herein by reference.

Item 1A. Risk Factors

The Annual Report on Form 10-K for the year ended December 31, 2014 includes a detailed discussion of risk factors. As of June 30, 2015, there have been no material changes to the risk factors previously disclosed in the 2014 Annual Report on Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None

Item 4. Mine Safety Disclosures

The Federal Mine Safety and Health Act of 1977 (Mine Act) imposes stringent health and safety standards on various mining operations. The Mine Act and its related regulations affect numerous aspects of mining operations, including training of mine personnel, mining procedures, equipment used in mine emergency procedures, mine plans and other matters. SWEPCo, through its ownership of DHLC, and AGR and KPCo, through their use of the Conner Run fly ash impoundment, are subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection Act and its related regulations require companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act. Exhibit 95 contains the notices of violation and proposed assessments received by DHLC and Conner Run under the Mine Act for the quarter ended June 30, 2015.

Item 5. Other Information

None

Item 6. Exhibits

3 – Composite of Amended Restated Certification of Incorporation of American Electric Power Company, Inc.

10 – Separation and Release Agreement – D.E. Welch

12 – Computation of Consolidated Ratio of Earnings to Fixed Charges

31(a) – Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31(b) – Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

32(a) – Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code
32(b) – Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

95 – Mine Safety Disclosures

101.INS – XBRL Instance Document
101.SCH – XBRL Taxonomy Extension Schema
101.CAL – XBRL Taxonomy Extension Calculation Linkbase
101.DEF – XBRL Taxonomy Extension Definition Linkbase
101.LAB – XBRL Taxonomy Extension Label Linkbase
101.PRE – XBRL Taxonomy Extension Presentation Linkbase

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature for each undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

APPALACHIAN POWER COMPANY
INDIANA MICHIGAN POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: July 23, 2015