AMERICAN ELECTRIC POWER CO INC
Form 10-Q
November 02, 2016

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 September 30, 2016
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 November 1, 2016
American Electric Power Company, Inc.	491,711,533 ($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
September 30, 2016

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	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, hedging activities, asset management and commercial and industrial sales in the deregulated Ohio and Texas market.
AEPRO	AEP River Operations, LLC.
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.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a competitive AEP subsidiary in the Generation & Marketing segment.
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 VI LLC, DCC Fuel VII, DCC Fuel VIII and DCC Fuel IX, consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
Desert Sky	Desert Sky Wind Farm, a 160.5 MW wind electricity generation facility located on Indian Mesa in Pecos County, Texas.
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.

i

Term	Meaning
ENEC	Expanded Net Energy Cost.
Energy Supply	AEP Energy Supply LLC, a nonregulated holding company for AEP's competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between Parent 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.
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.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PIRR	Phase-In Recovery Rider.

PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PPA	Power Purchase and Sale Agreement.
Price River	Rights and interests in certain coal reserves located in Carbon County, Utah.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.

Term	Meaning
PUCT	Public Utility Commission of Texas.
Putnam	Rights and interests in certain coal reserves located in Putnam, Mason and Jackson Counties, West Virginia.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants: APCo, I&M, OPCo, PSO and SWEPCo.
Registrants	SEC registrants: AEP, APCo, I&M, OPCo, PSO and SWEPCo.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RPM	Reliability Pricing Model.
RSR	Retail Stability Rider.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity for AEP and SWEPCo.
SEC	U.S. Securities and Exchange Commission.
SEET	Significantly Excessive Earnings Test.
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.
TRA	Tennessee Regulatory Authority.
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.
Trent	Trent Wind Farm, a 150 MW wind electricity generation facility located between Abilene and Sweetwater in West Texas.
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 the Registrants 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 2015 Annual Report, but there are others throughout this document which may be identified by words such as “expect,” “anticipate,” “intend,” “plan,” “believe,” “will,” “should,” “ “would,” “project,” “continue” and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, management undertakes 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 AEP service territories.

Inflationary or deflationary interest rate trends.

Volatility in the financial markets, particularly developments affecting the availability or cost of capital to finance new capital projects and refinance existing debt.

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 the ability to recover significant storm restoration costs.

The cost of fuel and its transportation and the creditworthiness and performance of fuel suppliers and transporters.

Availability of necessary generation capacity and the performance of generation plants.

The ability to recover fuel and other energy costs through regulated or competitive electric rates.

The ability to build transmission lines and facilities (including the 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 that could impact the continued operation, cost recovery and/or profitability of 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.

The ability to constrain operation and maintenance costs.

The ability to develop and execute a strategy based on a view regarding prices of electricity and gas.

Prices and demand for power generated and sold at wholesale.

Changes in technology, particularly with respect to energy storage and new, developing, alternative or distributed sources of generation.

The 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 market for generation in Ohio and PJM and the ability to recover investments in Ohio generation assets.
The ability to successfully and profitably manage competitive generation assets, including the evaluation and execution of strategic alternatives for these assets as some of the alternatives could result in a loss.
Changes in the creditworthiness of the counterparties with contractual arrangements, including participants in the energy trading market.
Actions of rating agencies, including changes in the ratings of debt.

The impact of volatility in the capital markets on the value of the investments held by the 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 the Registrants speak only as of the date of this report or as of the date they are made. The Registrants 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 2015 Annual Report and in Part II of this report.

Investors should note that the Registrants announce material financial information in SEC filings, press releases and public conference calls. Based on guidance from the SEC, the Registrants may use the Investors section of AEP's website (www.aep.com) to communicate with investors about the Registrants. It is possible that the financial and other information posted there could be deemed to be material information. The information on AEP's website is not part 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

AEP's weather-normalized retail sales volumes for the third quarter of 2016 decreased by 0.5% from the third quarter of 2015. AEP's third quarter 2016 industrial sales decreased 2.6% compared to the third quarter of 2015 primarily due to decreased sales to customers in the manufacturing sector. Weather-normalized residential sales increased by 1.2% and commercial sales decreased by 0.5% in the third quarter of 2016, respectively, from the third quarter of 2015.

AEP's weather-normalized retail sales volumes for the nine months ended September 30, 2016 decreased by 0.4% compared to the nine months ended September 30, 2015. AEP's industrial sales volumes for the nine months ended September 30, 2016 decreased 1.9% compared to the nine months ended September 30, 2015 primarily due to decreased sales to customers in the manufacturing sector. Weather-normalized residential and commercial sales increased by 0.5% and 0.4%, respectively, for the nine months ended September 30, 2016 compared to nine months ended September 30, 2015.

June 2015 - May 2018 ESP Including PPA Application and Proposed ESP Extension through 2024

In March 2016, a contested stipulation agreement related to the PPA rider application was modified and approved by the PUCO. The approved PPA rider is effective April 2016 through May 2024, subject to audit and review by the PUCO. The stipulation agreement, as approved, included (a) an Affiliate PPA between OPCo and AGR to be included in the PPA rider, (b) OPCo's OVEC PPA to be included in the PPA rider, (c) potential additional contingent customer credits of up to $100 million to be included in the PPA rider over the final four years of the PPA rider and (d) the limitation that OPCo will not flow through any capacity performance penalties or bonuses through the PPA rider. Additionally, subject to cost recovery and PUCO approval, OPCo agreed to develop and implement, by 2021, a solar energy project(s) of at least 400 MW and a wind energy project(s) of at least 500 MW, with 100% of all output to be received by OPCo. AEP affiliates could own up to 50% of these solar and wind projects. OPCo agreed to file a carbon reduction plan with the PUCO by December 2016 that will focus on fuel diversification and carbon emission reductions.

In March 2016, a group of merchant generation owners filed a complaint at the FERC against PJM seeking revisions to the Minimum Offer Price Rule (MOPR) in PJM's tariff. Although the complaint requested the FERC act in advance of the May 2016 Base Residual Auction for the 2019/2020 delivery year, the complaint is still pending without a decision from the FERC. If approved as proposed, the revised MOPR could affect future bidding behavior for units with cost recovery mechanisms.

In April 2016, the FERC issued an order granting a January 2016 complaint filed against AGR and OPCo. The FERC order rescinded the waivers of the FERC's affiliate rules as to the affiliate PPA between AGR and OPCo. As a result, AGR and OPCo cannot implement the affiliate PPA without the FERC review, in accordance with FERC's rules governing affiliate transactions. As a result of the April 2016 FERC order, management does not intend to pursue the affiliate PPA.

In May 2016, OPCo filed an application for rehearing with the PUCO related to certain aspects of the March 2016 PUCO order. The application included a proposed OVEC-only PPA Rider that included an option for the rider to be bypassable. The proposed OVEC-only PPA Rider included (a) the elimination of the PUCO-imposed customer-specific rate impact cap of 5% through May 2018, (b) modifications to proportionately decrease the amount of the potential customer credits and (c) the inclusion of PJM capacity performance penalties within the PPA rider. Also in May 2016, intervenors filed applications for rehearing with the PUCO opposing the modified and approved stipulation agreement.

OPCo has the option to exercise its right to withdraw from the PPA stipulation if the PUCO does not accept the requested modifications.

1

Consistent with the terms of the modified and approved stipulation agreement, in May 2016, OPCo filed an amended ESP that proposed to extend the ESP through May 2024. The amended ESP included (a) an extension of the PPA rider, which includes only OPCo's entitlements to its ownership percentage of OVEC, (b) a proposed 10.41% return on common equity on capital costs for certain riders, (c) the continuation of riders previously approved in the June 2015 - May 2018 ESP, (d) proposed increases in rate caps related to OPCo's Distribution Investment Rider and (e) the addition of various new riders, including a Generation Resource Rider. Based upon a September 2016 PUCO order, OPCo will refile its ESP extension application and supporting testimony in November 2016.

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.

Ohio Electric Security Plan Filings

2009 - 2011 ESP

In 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. 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 2015, the Supreme Court of Ohio issued a decision that reversed the PUCO order on the carrying cost rate issue and remanded the matter back to the PUCO for reinstatement of the WACC rate. In June 2016, the PUCO approved OPCo's proposed increase to the PIRR rates, in accordance with the Supreme Court of Ohio ruling. The increase to PIRR rates included $146 million in additional carrying charges and the recovery of $40 million in additional under-recovered fuel costs resulting from a decrease in customer demand. The increase is effective July 2016 through December 2018. In July 2016, intervenors filed requests for rehearing with the PUCO, which the PUCO granted in August 2016.

If the PUCO determines after rehearing that the additional PIRR carrying charges are not recoverable, it could reduce future net income and cash flows and impact financial condition.

June 2012 - May 2015 ESP Including Capacity Charge

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

In July 2012, the PUCO issued an order in a separate capacity proceeding requiring OPCo to 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 included reserve margins, was approximately $34/MW day through May 2014 and $150/MW day from June 2014 through May 2015. In April 2016, the Supreme Court of Ohio issued two opinions related to the deferral of OPCo's capacity charges. In one of the opinions, the Supreme Court of Ohio ruled that the PUCO must reconsider an energy credit that was used to determine OPCo's authorized capacity deferral threshold of $188.88/MW day during the August 2012 through May 2015 period. The PUCO reduced OPCo's authorized capacity deferral threshold to $188.88/MW day largely due to an offset for an energy credit of $147.41/MW day. The Supreme Court of Ohio directed the PUCO to substantively address OPCo's arguments that the $147.41/MW day credit was overstated by approximately $100/MW day due to various inaccuracies affecting input data and assumptions.

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 2015, the PUCO issued an order that modified and approved OPCo's July 2014 application to collect the unrecovered portion of the deferred capacity costs. As of September 30, 2016, OPCo's net deferred capacity costs balance was $239 million, including debt carrying costs. In April 2016, the second Supreme Court of Ohio opinion rejected a portion of OPCo's RSR revenues collected during the period September 2012 through May 2015 and directed the PUCO to reduce OPCo's deferred capacity costs by these previously collected RSR revenues. The Supreme Court of Ohio was not able to determine the amount of the reduction to OPCo's deferred capacity costs and remanded the issue to the PUCO to determine the appropriate reduction. As directed by the PUCO, in May 2016, OPCo submitted revised RSR tariffs that reflect the RSR being collected subject to refund.

In April 2016, the Supreme Court of Ohio also ruled favorably on OPCo's cross-appeal regarding a previously PUCO-imposed SEET threshold under the ESP and remanded this issue to the PUCO. See "Significantly Excessive Earnings Test Filings" section of Note 4.

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 November 2013, the PUCO issued an order approving OPCo's competitive bid process with modifications. 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 with the PUCO for the period August 2012 through May 2015. 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. Management believes that no over-recovery of costs has occurred and disagrees with the findings in the audit report.

In June 2016, OPCo filed a request with the PUCO that requested a consolidated procedural schedule to resolve interrelated proceedings including (a) OPCo's deferral of capacity costs for the period August 2012 through May 2015, (b) the implementation of OPCo's RSR and (c) the concerns related to the recovery of fixed fuel costs through both the FAC and the approved capacity charges. As part of the filing, OPCo requested that its net deferred capacity costs balance as of May 31, 2015 increase by $157 million, including carrying charges through September 2016. This net increase consists of a $327 million decrease due to the non-deferral portion of the RSR collections and an increase of $484 million for the correction of the energy credit. Recovery of the $157 million was requested to be effective October 2016 through December 2018. Additionally, OPCo filed testimony supporting the position that double recovery of fixed fuel costs could not have occurred because OPCo was unable to fully recover its capacity costs, which included fixed fuel costs, even with a corrected energy credit.

Due to the interrelated nature of the two Supreme Court of Ohio opinions that directly relate to OPCo's deferred capacity costs, management believes that the PUCO will rule upon these issues together. Further, management believes that the net impact of these issues will not result in a material future reduction of OPCo's net income. The recovery of fixed fuel costs will be addressed in a separate hearing scheduled for January 2017. See "2012 and 2013 Fuel Adjustment Clause Audits" section of Note 4.

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.

3

Merchant Generation Assets

In September 2016, AEP signed an agreement to sell Darby, Gavin, Lawrenceburg and Waterford Plants ("Disposition Plants") totaling 5,326 MWs of competitive generation for approximately $2.2 billion to a nonaffiliated party. The sale is subject to regulatory approvals from the FERC, the IURC and federal clearance pursuant to the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR). In October 2016, the Federal Trade Commission granted the sale early termination of the HSR waiting period thereby satisfying the HSR conditions to close the transaction. As of September 30, 2016, the net book value of these assets, including related materials and supplies inventory and CWIP, was $1.8 billion. AEP expects to receive net proceeds of approximately $1.2 billion in cash after taxes, debt retirement and transaction fees. AEP is evaluating options to invest these proceeds, including reinvestment in regulated businesses and renewable energy projects and additional debt retirement. The sale is expected to close in the first quarter of 2017. An after tax gain of approximately $150 million is expected from the sale subject to inventory true-ups, income tax and other adjustments.

The assets and liabilities included in the sale transaction have been recorded as Assets Held for Sale and Liabilities Held for Sale, respectively, on the balance sheet as of September 30, 2016. See "Assets and Liabilities Held for Sale" section of Note 6 for additional information.

In September 2016, due to AEP's ongoing evaluation of strategic alternatives for its merchant generation assets, declining forecasts of future energy and capacity prices, and a decreasing likelihood of cost recovery through regulatory proceedings or legislation in the state of Ohio providing for the recovery of AEP's existing Ohio merchant generation assets, AEP performed an impairment analysis at the unit level on the remaining merchant generation assets in accordance with accounting guidance for impairments of long-lived assets. The evaluation was performed using generating unit specific estimated future cash flows and resulted in a material impairment of certain merchant generation fleet assets. As a result, AEP recorded a pretax impairment of $2.3 billion ($1.5 billion, net of tax) in Asset Impairments and Other Related Charges on the statement of operations related to 2,684 MWs of Ohio merchant generation including Cardinal Unit 1, 43.5% ownership interest in Conesville Unit 4, Conesville Units 5-6, 26.0% ownership interest in Stuart Units 1-4, and 25.4% ownership interest in Zimmer Unit 1, as well as Putnam coal and I&M's Price River coal reserves, Desert Sky and Trent Wind Farms and the merchant generation portion of the Oklaunion Plant. As of September 30, 2016, the remaining net book value of these assets is $50 million. See "Merchant Generating Assets (Generation & Marketing Segment)" section of Note 6 for additional information.

Management continues to evaluate potential alternatives for the remaining merchant generation assets. These potential alternatives may include, but are not limited to, propose restructuring of Ohio electricity regulations to allow certain of these assets to be acquired by OPCo for the benefit of its customers, transfer or sale of AEP's ownership interests, or a wind down of merchant coal-fired generation fleet operations. AEP is also continuing a separate strategic review and evaluating alternatives related to the 48 MW Racine Hydroelectric Plant. Management has not set a specific time frame for a decision on these assets. These alternatives could result in additional losses which could reduce future net income and cash flows and impact financial condition.

Renewable Generation Portfolio

The growth of AEP's renewable generation portfolio reflects the company's strategy to diversify generation resources to provide clean energy options to customers that meet both their energy and capacity needs.

AEP has formed two new subsidiaries within the Generation & Marketing segment to further develop its renewable portfolio. AEP OnSite Partners, LLC works directly with wholesale and large retail customers to provide tailored solutions based upon market knowledge, technology innovations and deal structuring which may include distributed solar, wind, combined heat and power, energy storage, waste heat recovery, energy efficiency, peaking generation and other forms of cost reducing energy technologies. AEP OnSite Partners, LLC pursues projects where a suitable termed agreement is entered into with a credit-worthy counterparty. AEP Renewables, LLC develops and/or acquires large scale renewable generation projects that are backed with long-term contracts with credit-worthy counterparties. These subsidiaries have approximately 4 MW of renewable generation projects in operation and 56 MW of renewable generation projects under construction with an estimated financial commitment of approximately $119 million. As of September 30, 2016, $49 million of costs have been incurred related to these projects.

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 Utilities 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. As of September 30, 2016, the net book value of Turk Plant was $1.5 billion, before cost of removal, including materials and supplies inventory and CWIP.

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.

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 would review base rates in 2014 and 2015 and that SWEPCo would 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. A hearing at the LPSC related to the Turk Plant prudence review is scheduled for March 2017. 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.

Welsh Plant - Environmental Impact

Management currently estimates that the investment necessary to meet proposed environmental regulations through 2025 for Welsh Plant, Units 1 and 3 could cost approximately $850 million, excluding AFUDC. As of September 30, 2016, SWEPCo had incurred costs of $395 million, including AFUDC, and had remaining contractual construction obligations of $14 million related to these projects. As part of this investment, in 2016 SWEPCo completed construction of environmental control projects to meet Mercury and Air Toxics Standards for Welsh Plant, Units 1 and 3 at a cost of approximately $370 million, excluding AFUDC. Management continues to evaluate the impact of environmental rules and related project cost estimates. In March 2016, SWEPCo filed a request with the APSC to recover $69 million in environmental costs related to the Arkansas retail jurisdictional share of Welsh Plant, Units 1 and 3, which was approved by the APSC in August 2016. SWEPCo began recovering the Arkansas jurisdictional share of these costs in March 2016, subject to review in the next filed base rate proceeding. In September 2016, SWEPCo filed an additional request to increase the Arkansas retail jurisdictional share of the environmental investment by $10 million, for a total of $79 million. SWEPCo implemented the increase in September 2016.

SWEPCo will seek recovery of the remaining project costs from customers 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.

5

As of September 30, 2016, the net book value of Welsh Plant, Units 1 and 3 was $632 million, before cost of removal, including materials and supplies inventory and CWIP. In April 2016, Welsh Plant, Unit 2 was retired. Upon retirement, $76 million was reclassified as Regulatory Assets on the balance sheet related to the net book value of Welsh Plant, Unit 2 and the related asset retirement obligation costs. Management will seek recovery of the remaining regulatory assets in future rate proceedings.

If any of these costs are not recoverable, including retirement-related costs for Welsh Plant, Unit 2, it could reduce future net income and cash flows and impact financial condition.

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 of 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 common equity of 10.5% effective in January 2016. The proposed $44 million increase related to environmental investments was effective in March 2016, after the Northeastern Plant, Unit 3 environmental controls were placed 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 September 30, 2016, PSO had incurred costs of $180 million and $43 million, including AFUDC, for Northeastern Plant, Unit 3 and Comanche Plant, respectively.

In addition, the filing also notified the OCC that the incremental replacement capacity and energy costs, including the first year effects of new PPAs, estimated to be $35 million, will be incurred related to the environmental compliance plan due to the closure of Northeastern Plant, Unit 4, which would be recovered through the FAC. In April 2016, Northeastern Plant, Unit 4 was retired. Upon retirement, $87 million was reclassified as Regulatory Assets on the balance sheet related to the net book value of Northeastern Plant, Unit 4. These regulatory assets are pending regulatory approval.

In June 2016, an Administrative Law Judge (ALJ) issued a report related to PSO's base rate case filing and subsequently provided an additional supplemental report in August 2016. The ALJ recommended a 9.25% return on common equity. The ALJ found that PSO's environmental compliance plan is prudent and provided for cost recovery of the investment in this case with a recommended investment cap of $210 million on environmental controls installed at Northeastern Plant, Unit 3. Additionally, the ALJ recommendations included (a) a $14 million increase in depreciation expense, (b) continued depreciation of Northeastern Plant, Units 3 and 4 through 2040 (no accelerated depreciation), (c) return of, but no return on, the remaining net book value of Northeastern Plant, Unit 4, (d) elimination of the rider to recover advanced metering starting in December 2016, without inclusion in base rates and (e) elimination of the system reliability rider through consolidation in base rates, without addressing a transition for recovery of rider costs, including deferred costs. The estimated annual revenue increase resulting from the ALJ recommendations is approximately $47 million.

In June and September 2016, PSO, the OCC staff, the Attorney General and intervenors filed exceptions to the ALJ reports. The OCC staff filed exceptions that supported the full recovery of Northeastern Plant, Unit 4, including a return, and recommended a $32 million increase in annual revenues. An order from the OCC is anticipated in the fourth quarter of 2016.

If any of these costs, including a return on Northeastern Plant, Unit 4, 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.

6

Indiana Amended PJM Settlement Agreement

In September 2016, I&M and certain intervenors filed an amended settlement agreement with the IURC. This agreement amends a previously approved 2014 settlement agreement that addresses the recovery of 43.5% of certain transmission expenses through the Indiana PJM rider through 2017.

The amended agreement allows I&M to recover 100% of the Indiana jurisdictional share of these transmission expenses not recovered through base rates through the Indiana PJM rider, subject to a $109 million cap for the period January 2017 through June 2018. Beginning July 2018, I&M will be allowed to recover 100% of the Indiana jurisdictional share of these transmission expenses through the Indiana PJM rider, without a cap, until the issue is addressed by the IURC in a future proceeding, subject to the condition that I&M files a base rate case on or before January 2018. The amended agreement also provides for deferral of incremental vegetation management expenses over the period January 2017 through June 2018. Any vegetation management expenses deferred would reduce the cap for the transmission expenses described above. As part of the amended settlement, I&M agreed that it will not file a base rate case before July 2017 and will not implement new base rates prior to July 2018. A hearing at the IURC was held in October 2016.

Rockport Plant, Unit 2 Selective Catalytic Reduction (SCR)

In October 2016, I&M filed an application with the IURC for approval of a Certificate of Public Convenience and Necessity (CPCN) to install SCR technology at Rockport Plant, Unit 2 by December 2019. The equipment will allow I&M to reduce emissions of NO_x from Rockport Plant, Unit 2 in order for I&M to continue to operate that unit under current environmental requirements. The estimated cost of the SCR project is $274 million, excluding AFUDC, to be shared equally between I&M and AEGCo. The filing included a request for authorization for I&M to defer its Indiana jurisdictional ownership share of costs including investment carrying costs, depreciation over a 10-year life and other related expenses. I&M proposed recovery of these costs using the existing Clean Coal Technology Rider. The AEGCo ownership share of the proposed SCR project will be billable under the Rockport Unit Power Agreement to affiliates, including I&M, with I&M's share recoverable in its base rates.

TCC and TNC Merger

In June 2016, TCC and TNC filed applications with the PUCT and FERC that requested approval to merge TCC and TNC into AEP Utilities, Inc. Upon merger, AEP Utilities, Inc. will change its name to AEP Texas Inc. The proposed merger would be effective December 31, 2016. The applications proposed no changes to current TCC and TNC rates. A hearing at the PUCT was held in August 2016. In September 2016, the FERC issued an order approving the merger application. In October 2016, the ALJ issued a proposal for decision that recommends approval of the merger provided certain post-merger conditions are imposed. The conditions recommended by the ALJ include a) the sharing of certain interest rate savings with customers and b) an annual credit to customers of approximately $630 thousand for savings resulting from an expected reduction in post-merger debt issuance costs, effective until the next base rate case. Management is evaluating the conditions recommended by the ALJ. A decision from the PUCT is expected in the fourth quarter of 2016.

FERC Transmission Complaint

In October 2016, several parties filed a joint complaint with the FERC that states the base return on common equity used by various AEP affiliates in calculating formula transmission rates under the PJM Open Access Transmission Tariff (OATT) is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. Management is reviewing the filing and evaluating a response to the complaint. Management is unable to determine a range of potential losses, if any, that is reasonably possible of occurring. If the FERC orders revenue reductions, including refunds from the date of filing, it could reduce future net income and cash flows and impact financial condition.

7

Kingsport Base Rate Case

In January 2016, KGPCo filed a request with the TRA to increase base rates by $12 million annually based upon a proposed return on common equity of 10.66%. In August 2016, the TRA approved a settlement agreement that included an $8 million annual increase in base rates with a 9.85% return on common equity effective September 2016.

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 amendments provide 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 asset impairments related to new carbon emission guidelines issued by the Federal EPA.

In February 2016, certain APCo industrial customers filed a petition with the Virginia SCC requesting the issuance of a declaratory order that finds the amendments to Virginia law suspending biennial reviews unconstitutional and, accordingly, directs APCo to make biennial review filings beginning in 2016. In July 2016, the Virginia SCC issued an order that denied the petition. In July 2016, intervenors, including certain APCo industrial customers, filed an appeal of the order with the Supreme Court of Virginia. Management is unable to predict the outcome of these challenges to the Virginia legislation. If the biennial review process is reinstated in advance of March 2020, it could reduce future net income and cash flows and impact financial condition.

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.

In June 2015, FERC approved PJM’s proposal to create a new Capacity Performance (CP) product, intended to improve generator performance and reliability during emergency events by allowing higher offers into the RPM auction and imposing greater charges for non-performance during emergency events. PJM procured approximately 80% CP and 20% Base Capacity for the June 2018 through May 2019 and June 2019 through May 2020 periods, while transitioning to 100% CP with the June 2020 through May 2021 period. FERC also approved transition incremental auctions to procure CP for the June 2016 through May 2017 and June 2017 through May 2018 periods.

In the third quarter of 2015, PJM conducted the two transition auctions. The transition auctions allowed generators, including AGR, to re-offer cleared capacity that qualifies as CP. Shown below are the results of the two transition auctions:

PJM Auction Period	Capacity Performance Transition Incremental Auction Price (dollars per MW day)
June 2016 through May 2017	134.00
June 2017 through May 2018	151.50

AGR cleared 7,169MW at $134/MW-day for the June 2016 through May 2017 period, replacing the original auction clearing price of $59.37/MW-day. AGR cleared 6,495MW for the June 2017 through May 2018 period at

$151.50/MW-day, replacing the original auction clearing price of $120/MW-day.

In August 2015, PJM held its first base residual auction implementing CP rules for the June 2018 through May 2019 period. AGR cleared 7,209 MW at the CP auction price of $164.77/MW-day. The base residual auction for the June 2019 through May 2020 period was conducted in May 2016. AGR cleared 7,301 MW at the CP auction price of $100/MW-day. Shown below are the results for the June 2018 through May 2019 and June 2019 through May 2020 periods:

PJM Auction Period	Capacity Performance Auction Price (dollars per MW day)	Base Capacity Auction Price (dollars per MW day)
June 2018 through May 2019	164.77	150.00
June 2019 through May 2020	100.00	80.00

Once the pending sale of the Darby, Gavin, Lawrenceburg and Waterford Plants is closed, AGR will not be responsible for or receive capacity revenue for the portion of the cleared capacity associated with these plants.

The FERC order exempted Fixed Resource Requirement (FRR) entities, including APCo, I&M, KPCo and WPCo, from the CP rules through the delivery period ending May 2019. Beginning in June 2019, FRR entities are subject to CP rules.

LITIGATION

In the ordinary course of business, AEP 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 that have a probable likelihood of loss if the loss can be estimated. For details on the 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 2015 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 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 plaintiff’s claims. Several claims remained, 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. The plaintiff subsequently filed an amended complaint to add another claim under the lease and also filed a motion for partial summary judgment. In November 2015, AEGCo and I&M filed a motion to strike the plaintiff’s motion for partial judgment and filed a motion to dismiss the case for failure to state a claim. In March 2016, the court entered an opinion and order in favor of AEGCo and I&M, dismissing certain of the plaintiffs’ claims for breach of contract and dismissing claims for breach of implied covenant of good faith and fair dealing, and further dismissing plaintiffs' claim for indemnification of costs. By the same order, the court permitted plaintiffs to move forward with their claim that AEGCo and I&M failed to exercise prudent utility practices in the maintenance and operation of Rockport Plant, Unit 2. In April 2016, the plaintiffs filed a notice of voluntary dismissal of all remaining claims with prejudice and the court subsequently entered a final judgment. In May 2016, Plaintiffs filed a notice of appeal on whether AEGCo and

9

I&M are in breach of certain contract provisions that Plaintiffs allege operate to protect the Plaintiffs' residual interests in the unit and whether the trial court erred in dismissing Plaintiffs' claims that AEGCo and I&M breached the covenant of good faith and fair dealing. This matter is currently pending before the U.S. Court of Appeals for the Sixth Circuit. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

ENVIRONMENTAL ISSUES

AEP is implementing a substantial capital investment program and incurring additional operational costs to comply with environmental control requirements. Additional investments and operational changes will need to be made in response to existing and anticipated requirements such as CAA requirements to reduce emissions of SO_2, NO_x, PM, CO_2 and hazardous air pollutants (HAPs) from fossil fuel-fired power plants, rules governing the beneficial use and disposal of coal combustion products, clean water rules and renewal permits for certain water discharges.

AEP is engaged in litigation about environmental issues, was notified of potential responsibility for the clean-up of contaminated sites and incurred costs for disposal of SNF and future decommissioning of the nuclear units. AEP, along with various industry groups, affected states and other parties 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 state plans to reduce 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 "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2015 Annual Report. AEP 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 AEP is 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. Management continues to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of September 30, 2016, the AEP System had a total generating capacity of approximately 31,000 MWs, of which approximately 16,000 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 fossil generating facilities. Based upon management estimates, AEP's investment to meet these proposed requirements ranges from approximately \$2.8 billion to \$3.4 billion through 2025. Management continues to evaluate the impact of the merchant fleet operations on this range. The estimates include investments to convert some of the coal generation to natural gas.

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 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 addition, management is continuing to evaluate the economic feasibility of environmental investments on both regulated and competitive plants.

10

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

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 September 30, 2016, the net book value of the AGR units listed above was zero. 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 approved for recovery, except for $144 million which management plans to seek regulatory approval.

In April 2016, AEP retired the following units of plants:

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 September 30, 2016, the net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of the PSO and SWEPCo units listed above was $161 million. For Northeastern Station, Unit 4, PSO is seeking regulatory recovery of remaining net book values. For Welsh Plant, Unit 2, SWEPCo will seek regulatory recovery of remaining net book values.

In October 2015, KPCo obtained permits following the KPSC’s approval to convert its 278 MW Big Sandy Plant, Unit 1 to natural gas. Big Sandy Plant, Unit 1 began operations as a natural gas unit in May 2016.

APCo obtained permits following the Virginia SCC’s and WVPSC’s approval to convert its 470 MW Clinch River Plant, Units 1 and 2 to natural gas. In the third and fourth quarters of 2015, APCo retired the coal-related assets of Clinch River Plant, Units 1 and 2. Of the retired coal related assets for Clinch River Plant, Units 1 and 2, management plans to seek regulatory approval for $24 million. Clinch River Plant, Unit 1 and Unit 2 began operations as natural gas units in February 2016 and April 2016, respectively.

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.

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. In July 2015, the U.S. Court of Appeals for the District of Columbia Circuit remanded the rule to the Federal EPA. In September 2016, the Federal EPA finalized its response to the remand for ozone season NO_x budgets. All of the states in which AEP's power plants are located are covered by CSAPR. See "Cross-State Air Pollution Rule" section below.

The Federal EPA issued the final maximum achievable control technology (MACT) standards for coal and oil-fired power plants in 2012, but the rule was remanded to the Federal EPA upon further review. The Federal EPA issued a supplemental finding, received comments and affirmed its decision on the MACT standards for power plants. That decision has been challenged in the courts but the rule remains in effect. 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 were consistent with the environmental controls currently under construction. In September 2016, the Federal EPA published a final FIP that retains its BART determinations, but accelerates the schedule for implementation of certain required controls. 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. Management supports compliance with CSAPR programs as satisfaction of the BART requirements. The Federal EPA also proposed revisions to the requirements for submission of visibility SIPs by the states for future planning periods.

The Federal EPA issued rules for CO_2 emissions that apply to new and existing electric utility units. See "Climate Change, CO_2 Regulation and Energy Policy" section below.

The Federal EPA also issued new, more stringent national ambient air quality standards (NAAQS) for PM, SO_2 and ozone. In October 2015, the Federal EPA announced a lower final NAAQS for ozone of 70 parts per billion. 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 AEP's operations are discussed in the following sections.

Cross-State Air Pollution Rule

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. A 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 filed briefs and presented oral arguments. In July 2015, the U.S. Court of Appeals for the District of Columbia Circuit found that the Federal EPA over-controlled the SO_2 and/or NO_x budgets of 14 states. The U.S. Court of Appeals for the District of Columbia Circuit remanded the rule to the Federal EPA to timely revise the rule consistent with the court's opinion while CSAPR remains in place.

In December 2015, the Federal EPA issued a proposal to revise the ozone season NO_x budgets in 23 states beginning in 2017 to address transport issues associated with the 2008 ozone standard and the budget errors identified in the U.S. Court of Appeals for the District of Columbia Circuit's July 2015 decision. The proposal was open for public comment through February 1, 2016. A final rule has been signed that addressed some of the concerns raised in comments, but will significantly reduce ozone season budgets in many states and discounts the value of banked CSAPR ozone season allowances. Management believes that there are flaws in the underlying analysis of and justification for this rule. Management is evaluating compliance options for the 2017 ozone season, including any opportunity to further optimize NO_x emissions and availability of allowances.

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. Management 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.

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. The U.S. Court of Appeals for the District of Columbia Circuit remanded the Mercury and Air Toxics Standards (MATS) rule for further proceedings consistent with the U.S. Supreme Court's 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 Federal EPA issued notice of a supplemental finding concluding that it is appropriate and necessary to regulate HAP emissions from coal-fired and oil-fired units. Management submitted comments on the proposal. In April 2016, the Federal EPA affirmed its determination that regulation of HAPs from electric generating units is necessary and appropriate. Petitions for review of the Federal EPA's April 2016 determination have been filed in the U.S. Court of Appeals for the District of Columbia Circuit. The rule remains in effect.

Climate Change, CO_2 Regulation and Energy Policy

The majority of the states where AEP has generating facilities passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements that can assist in reducing carbon emissions. Management is taking steps to comply with these requirements, including increasing wind power purchases and broadening the AEP System's portfolio of energy efficiency programs.

In October 2015, the Federal EPA published the final standards for new, modified and reconstructed fossil fired steam generating units and combustion turbines, and final guidelines for the development of state plans to regulate CO_2 emissions from existing sources. The final standard for new combustion turbines is 1,000 pounds of CO_2 per MWh and the final standard for new fossil steam units is 1,400 pounds of CO_2 per MWh. Reconstructed turbines are subject to the same standard as new units and no standard for modified combustion turbines was issued. Reconstructed fossil steam units are subject to a standard of 1,800 pounds of CO_2 per MWh for larger units and 2,000 pounds of CO_2 per MWh for smaller units. Modified fossil steam units will be subject to a site specific standard no lower than the standards that would be applied if the units were reconstructed.

The final emissions guidelines for existing sources, known as the Clean Power Plan (CPP), are based on a series of declining emission rates that are implemented beginning in 2022 through 2029. The final emission rate is 771 pounds of CO_2 per MWh for existing natural gas combined cycle units and 1,305 pounds of CO_2 per MWh for existing fossil steam units in 2030 and thereafter. The Federal EPA also developed a set of rate-based and mass-based state goals.

The Federal EPA also published proposed "model" rules that can be adopted by the states that would allow sources within "trading ready" state programs to trade, bank or sell allowances or credits issued by the states. These rules would also be the basis for any federal plan issued by the Federal EPA in a state that fails to submit or receive approval for a state plan. The Federal EPA intends to finalize either a rate-based or mass-based trading program that can be enforced in states that fail to submit approved plans by the deadlines established in the final guidelines. The Federal EPA established a 90-day public comment period on the proposed rules and management submitted comments. In June 2016, the Federal EPA issued a separate proposal for the Clean Energy Incentive Program (CEIP) that was included in the model rules. The Federal EPA will accept comments on the proposed rules through November 1, 2016. Through the CEIP, states could issue allowances or credits for eligible actions prior to the first compliance period under the CPP. Management is evaluating the potential impacts of the final CPP and the proposed CEIP, as well as the anticipated actions by states where assets are located. The final rules are being challenged in the courts. In February 2016, the U.S. Supreme Court issued a stay on the final Clean Power Plan, including all of the deadlines for submission of initial or final state plans. The stay will remain in effect until a final decision is issued by the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court considers any petition for review.

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 AEP to close some coal-fired facilities and could lead to possible impairment of assets.

Coal Combustion Residual Rule

In April 2015, the Federal EPA published a final 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 final rule became effective in October 2015. The Federal EPA regulates CCR as a non-hazardous solid waste by its issuance of new minimum federal solid waste management standards. 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, 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. The CCR rule requirements contain a compliance schedule spanning an approximate four year implementation period. If CCR units do not meet these standards within the timeframes provided, they will be required to close. Extensions of time for closure are available provided there is no alternative disposal capacity or the owner can certify cessation of a boiler by a certain date. Challenges to the rule by industry associations of which AEP is a member are proceeding. In April 2016, the parties entered into a settlement agreement that would require the Federal EPA to reconsider certain aspects of the rule. In June 2016, the U.S. Court of Appeals for the District of Columbia issued an order granting the voluntary remand of certain provisions including the Federal EPA's issuance of a rule vacating the provision creating specific closure requirements for inactive surface impoundments that complete closure by April 17, 2018. In August 2016, the Federal EPA proposed a direct final rule to extend the deadlines for these facilities to comply with the CCR standards. The proposed rule received no adverse comments and became effective 60 days following publication. Management does not believe the direct final rule will have a significant impact on its planned pond closures. The Federal EPA will also use its best efforts to complete reconsideration of all of the affected provisions within three years.

Because AEP currently uses surface impoundments and landfills to manage CCR materials at generating facilities, significant costs will be incurred to upgrade or close and replace these existing facilities at some point in the future as the new rule is implemented. Management recorded a $95 million increase in asset retirement obligations in the second quarter of 2015 primarily due to the publication of the final rule. Management will continue to evaluate the rule's impact on operations.

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 AEP'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.

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. Briefs by the various parties are due during the fourth quarter of 2016.

In addition, the Federal EPA developed revised effluent limitation guidelines for electricity generating facilities. A final rule was issued in November 2015. The rule has been challenged in the U.S. Court of Appeals for the Fifth Circuit. Industry petitioners, including SWEPCo, have filed a joint motion for reconsideration of the single judge order denying the motion to complete the administrative record. In addition to other requirements, the final rule establishes limits on flue gas desulfurization wastewater, zero discharge for fly ash and bottom ash transport water and flue gas mercury control wastewater. The applicability of these requirements is as soon as possible after November 2018 and no later than December 2023. These new requirements will be implemented through each facility’s wastewater discharge permit. Management continues to assess technology additions and retrofits.

In June 2015, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a final rule to clarify the scope of the regulatory definition of "waters of the United States" in light of recent U.S. Supreme Court cases. The CWA provides for federal jurisdiction over "navigable waters" defined as "the waters of the United States." This jurisdictional definition applies 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. 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 believes that clarity and efficiency in the permitting process is needed. Management remains concerned that the rule introduces new concepts and could subject more of AEP's operations to CWA jurisdiction, thereby increasing the time and complexity of permitting. The final rule is being challenged in both courts of appeal and district courts. Challengers include industry associations of which AEP is a member. The U.S. Court of Appeals for the Sixth Circuit granted a nationwide stay of the rule pending jurisdictional determinations. In February 2016, the U.S. Court of Appeals for the Sixth Circuit issued a decision holding that it has exclusive jurisdiction to decide the challenges to the "waters of the United States" rule. Industry, state and related associations have filed petitions for a rehearing of the jurisdictional decision. In April 2016, the U.S. Court of Appeals for the Sixth Circuit denied the petitions and proceeded to issue a case management order for the merits of the case. In September 2016, the case management order was held in abeyance pending the court's ruling on the outstanding motions to complete the administrative record. In October 2016, the U.S. Court of Appeals for the Sixth Circuit issued an order granting in part and denying in part the motions to complete the record. Following this order, a revised case management order was issued scheduling briefing to be completed by March 2017. No date for oral argument has been set.

RESULTS OF OPERATIONS

SEGMENTS

AEP's primary business is the generation, transmission and distribution of electricity. Within its Vertically Integrated Utilities segment, AEP centrally dispatches generation assets and manages its 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.

AEP's 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 AEP's wholly-owned transmission-only subsidiaries and transmission-only joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

Generation & Marketing

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

The remainder of AEP's 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, Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs. With the sale of AEPRO in November 2015, the activities related to the AEP River Operations segment have been moved to Corporate and Other for the periods presented. See "AEPRO (Corporate and Other Segment)" section of Note 6 for additional information.

The following discussion of AEP's results of operations by operating segment includes an analysis of gross margin, which is a non-GAAP financial measure. Gross margin includes Total Revenues less the costs of Fuel and Other Consumables Used for Electric Generation as well as Purchased Electricity for Resale, as presented in AEP's statements of operations. These expenses are generally collected from customers through cost recovery mechanisms. As such, management uses gross margin for internal reporting analysis as it excludes the fluctuations in revenue caused by changes in these expenses. Operating income, which is presented in accordance with GAAP in AEP's statements of operations, is the most directly comparable GAAP financial measure to the presentation of gross margin. AEP's definition of gross margin may not be directly comparable to similarly titled financial measures used by other companies.

The table below presents Earnings (Loss) Attributable to AEP Common Shareholders by segment for the three and nine months ended September 30, 2016 and 2015.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Vertically Integrated Utilities	$342.3	$273.5	$829.3	$779.7
Transmission and Distribution Utilities	155.5	113.0	388.1	287.8
AEP Transmission Holdco	69.0	45.6	207.5	146.6
Generation & Marketing	(1,369.2)	91.6	(1,248.8)	360.3
Corporate and Other	36.6	(5.4)	61.4	3.1
Earnings (Loss) Attributable to AEP Common Shareholders	$(765.8)	$518.3	$237.5	$1,577.5

AEP CONSOLIDATED

Third Quarter of 2016 Compared to Third Quarter of 2015

Earnings (Loss) Attributable to AEP Common Shareholders decreased from income of $518 million in 2015 to a loss of $766 million in 2016 primarily due to:

- An impairment of certain merchant generation assets.
- A decrease in weather-normalized sales.

These decreases were partially offset by:

- A decrease in system income taxes primarily due to reduced pretax book income as a result of the impairment of certain merchant generation assets as well as the reversal of valuation allowances related to the pending sale of certain merchant generation assets, as well as favorable 2015 income tax return adjustments related to AEP's commercial barging operations.
- An increase in weather-related usage.
- Favorable rate proceedings in AEP's various jurisdictions.
- An increase due to increased revenues from Ohio transmission and distribution riders.
- An increase in income at AEP Transmission Holdco as a result of increased transmission investment and related increases in recoverable operating expenses.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015

Earnings (Loss) Attributable to AEP Common Shareholders decreased from income of $1.6 billion in 2015 to income of $238 million in 2016 primarily due to:

- An impairment of certain merchant generation assets.
- A decrease in generation revenues due to lower capacity revenue and a decrease in wholesale energy prices.
- A decrease in weather-related usage.

These decreases were partially offset by:

- A decrease in system income taxes primarily due to reduced pretax book income as a result of the impairment of certain merchant generation assets as well as the reversal of valuation allowances related to the pending sale of certain merchant generation assets and the settlement of a 2011 audit issue with the IRS, as well as favorable 2015 income tax return adjustments related to AEP's commercial barging operations.

- An increase due to increased revenues from Ohio transmission and distribution riders.
- An increase in income at AEP Transmission Holdco as a result of increased transmission investment as well as an increase due to annual formula rate true-up adjustments.

AEP's results of operations by operating segment are discussed below.

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
	(in millions)			
Revenues	$2,556.3	$2,471.5	$6,927.8	$7,159.1
Fuel and Purchased Electricity	858.3	931.0	2,299.8	2,694.8
Gross Margin	1,698.0	1,540.5	4,628.0	4,464.3
Other Operation and Maintenance	673.0	652.8	1,926.9	1,843.4
Asset Impairments and Other Related Charges	10.5	—	10.5	—
Depreciation and Amortization	277.7	264.0	815.5	802.4
Taxes Other Than Income Taxes	99.0	97.6	295.0	288.2
Operating Income	637.8	526.1	1,580.1	1,530.3
Interest and Investment Income	0.8	0.7	2.4	3.9
Carrying Costs Income	0.8	3.4	8.1	8.5
Allowance for Equity Funds Used During Construction	10.0	15.4	35.4	45.5
Interest Expense	(136.7)	(129.1)	(399.9)	(391.5)
Income Before Income Tax Expense and Equity Earnings	512.7	416.5	1,226.1	1,196.7
Income Tax Expense	172.0	142.4	398.4	416.1
Equity Earnings of Unconsolidated Subsidiaries	2.7	0.4	4.9	2.1
Net Income	343.4	274.5	832.6	782.7
Net Income Attributable to Noncontrolling Interests	1.1	1.0	3.3	3.0
Earnings Attributable to AEP Common Shareholders	$342.3	$273.5	$829.3	$779.7

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
	(in millions of KWhs)			
Retail:				
Residential	9,575	9,019	25,373	26,070
Commercial	7,137	7,008	19,207	19,315
Industrial	8,655	8,882	25,576	26,178
Miscellaneous	634	616	1,740	1,739
Total Retail	26,001	25,525	71,896	73,302
Wholesale (a)	6,765	6,577	17,253	20,748
Total KWhs	32,766	32,102	89,149	94,050

(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 the eastern region have a larger effect on revenues than changes in the 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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in degree days)			
Eastern Region				
Actual – Heating (a)	—	—	1,684	2,138
Normal – Heating (b)	5	5	1,775	1,748
Actual – Cooling (c)	954	702	1,306	1,104
Normal – Cooling (b)	726	728	1,058	1,057
Western Region				
Actual – Heating (a)	—	—	685	1,049
Normal – Heating (b)	1	1	927	912
Actual – Cooling (c)	1,519	1,472	2,262	2,190
Normal – Cooling (b)	1,400	1,398	2,116	2,114

(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) Cooling degree days are calculated on a 65 degree temperature base.

Third Quarter of 2016 Compared to Third Quarter of 2015
Reconciliation of Third Quarter of 2015 to Third Quarter of 2016
Earnings Attributable to AEP Common Shareholders from
Vertically Integrated Utilities
(in millions)

Third Quarter of 2015	$273.5
Changes in Gross Margin:	
Retail Margins	136.2
Off-system Sales	3.5
Transmission Revenues	13.4
Other Revenues	4.4
Total Change in Gross Margin	157.5
Changes in Expenses and Other:	
Other Operation and Maintenance	(20.2)
Asset Impairments and Other Related Charges	(10.5)
Depreciation and Amortization	(13.7)
Taxes Other Than Income Taxes	(1.4)
Interest and Investment Income	0.1
Carrying Costs Income	(2.6)
Allowance for Equity Funds Used During Construction	(5.4)
Interest Expense	(7.6)
Total Change in Expenses and Other	(61.3)
Income Tax Expense	(29.6)
Equity Earnings	2.3
Net Income Attributable to Noncontrolling Interests	(0.1)
Third Quarter of 2016	$342.3

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 $136 million primarily due to the following:
- The effect of rate proceedings in AEP's service territories which included:
- A $35 million increase due to increases in rates in West Virginia and Virginia.
- A $24 million increase for PSO due to interim base rate increases.
- A $17 million increase for I&M due to increases in riders in the Indiana service territory.
- A $16 million increase for KPCo primarily due to increases in base rates and riders.
- A $6 million increase for SWEPCo due to revenue increases from rate riders in Texas and Arkansas.

For the increases described above, $55 million relate to riders/trackers which have corresponding increases in expense items below.

- A $53 million increase in weather-related usage.
- A $3 million increase for SWEPCo in municipal and cooperative revenues due to formula rate adjustments.

These increases were partially offset by:

- A $27 million decrease primarily due to lower weather-normalized margins.

- Margins from Off-system Sales increased $4 million primarily due to increased sales volumes.
- Transmission Revenues increased $13 million primarily due to the following:
- A $5 million accrual for SPP sponsor-funded transmission upgrades. This increase was offset by a corresponding increase in Other Operation and Maintenance expenses below.
- A $5 million increase due to higher Network Integration Transmission Service revenues associated with increased transmission investments.

- A $4 million increase in SPP Non-Affiliated Base Plan Funding associated with increased transmission investments. This increase was offset by a corresponding increase in Other Operation and Maintenance expenses below.
- Other Revenues increased $4 million primarily due to increased revenues from Demand Side Management (DSM) programs in Kentucky.

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

- Other Operation and Maintenance expenses increased $20 million primarily due to the following:
- A $51 million increase in recoverable expenses, primarily including PJM, Big Sandy Unit 1 operation rider, energy efficiency and vegetation management expenses fully recovered in rate recovery riders/trackers.
- A $17 million increase associated with amortization of deferred transmission costs in accordance with the Virginia Transmission Rate Adjustment Clause effective January 2016. This increase in expense is offset within Retail Margins above.
- A $12 million accrual for SPP sponsor-funded transmission upgrades. This increase was partially offset by a corresponding increase in Transmission Revenues above.

These increases were partially offset by:

- A $33 million decrease in employee and AEPSC related expenses.
- An $18 million decrease in plant outages and maintenance primarily in the eastern region.
- A $6 million decrease in vegetation management expenses.
- Asset Impairments and Other Related Charges increased $11 million due to the impairment of I&M's Price River Coal reserves.
- Depreciation and Amortization expenses increased $14 million primarily due to:
- A $12 million increase due to a higher depreciable base.
- A $9 million increase in depreciation primarily related to interim rate increases in Oklahoma.

These increases were partially offset by:

- A $3 million decrease in amortization related to the advanced metering infrastructure projects in Oklahoma.
- A $3 million decrease in the amortization of capitalized software due to prior year retirements.
- Allowance for Equity Funds Used During Construction decreased $5 million primarily due to the completion of environmental projects at SWEPCo.
- Interest Expense increased $8 million primarily due to the following:
- A $4 million increase due to higher long-term debt balances at I&M.
- A $4 million increase due to a decrease in the debt component of AFUDC as a result of decreased environmental projects at SWEPCo.
- Income Tax Expense increased $30 million primarily due to an increase in pretax book income.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015
Reconciliation of Nine Months Ended September 30, 2015 to
Nine Months Ended September 30, 2016
Earnings Attributable to AEP Common Shareholders from
Vertically Integrated Utilities
(in millions)

Nine Months Ended September 30, 2015	$779.7
Changes in Gross Margin:	
Retail Margins	191.9
Off-system Sales	(19.7)
Transmission Revenues	(14.3)
Other Revenues	5.8
Total Change in Gross Margin	163.7
Changes in Expenses and Other:	
Other Operation and Maintenance	(83.5)
Asset Impairments and Other Related Charges	(10.5)
Depreciation and Amortization	(13.1)
Taxes Other Than Income Taxes	(6.8)
Interest and Investment Income	(1.5)
Carrying Costs Income	(0.4)
Allowance for Equity Funds Used During Construction	(10.1)
Interest Expense	(8.4)
Total Change in Expenses and Other	(134.3)
Income Tax Expense	17.7
Equity Earnings	2.8
Net Income Attributable to Noncontrolling Interests	(0.3)
Nine Months Ended September 30, 2016	$829.3

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 $192 million primarily due to the following:
- The effect of rate proceedings in AEP's service territories which include:
- A $120 million increase primarily due to increases in rates in West Virginia and Virginia, which includes recognition of deferred billing in West Virginia as approved by the WVPSC in June 2016. This increase is partially offset by a prior year adjustment affected by the amended Virginia law that has an impact on biennial reviews.
- A $45 million increase for KPCo primarily due to increases in base rates and riders.
- A $43 million increase for PSO due to interim base rate increases.
- A $29 million increase for I&M due to increases in riders in the Indiana service territory.
- A $16 million increase for SWEPCo due to revenue increases from rate riders in Arkansas and Texas.

For the increases described above, $139 million relate to riders/trackers which have corresponding increases in expense items below.
These increases were partially offset by:

- A $29 million decrease in weather-related usage.
- A $14 million decrease in weather-normalized margins primarily in the eastern region.
- A $22 million decrease for SWEPCo in municipal and cooperative revenues due to a true-up of formula rates in 2015.
- A $12 million decrease for I&M in FERC municipal and cooperative revenues due to annual formula rate adjustments offset by increased formula rate changes.

- Margins from Off-system Sales decreased $20 million primarily due to lower market prices and decreased sales volumes.
- Transmission Revenues decreased $14 million primarily due to the following:
  - A $26 million decrease due to lower Network Integration Transmission Service revenues.

  This decrease was partially offset by:
  - A $9 million increase in SPP Non-Affiliated Base Plan Funding associated with increased transmission investments. This increase was offset by a corresponding increase in Other Operation and Maintenance expenses below.
  - A $5 million accrual for SPP sponsor-funded transmission upgrades. This increase was offset by a corresponding increase in Other Operation and Maintenance expenses below.
- Other Revenues increased $6 million primarily due to increased revenues from DSM programs in Kentucky.

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

- Other Operation and Maintenance expenses increased $84 million primarily due to the following:
  - A $72 million increase in recoverable expenses, primarily including PJM, vegetation management, energy efficiency and storm expenses fully recovered in rate recovery riders/trackers.
  - A $41 million increase associated with amortization of deferred transmission costs in accordance with the Virginia Transmission Rate Adjustment Clause effective January 2016. This increase in expense is offset within Retail Margins above.
  - A $27 million increase in SPP and PJM transmission services expense.
  - A $12 million accrual for SPP sponsor-funded transmission upgrades. This increase was partially offset by a corresponding increase in Transmission Revenues above.
  - A $9 million increase in distribution expenses primarily due to increased asset inspections.
  - A $6 million increase due to the reduction of an environmental liability in 2015 at I&M.
  - A $6 million increase in storm expenses, primarily in the APCo region.

  These increases were partially offset by:
  - A $60 million decrease in plant outages, primarily planned outages in the eastern region.
  - A $13 million decrease in vegetation management expenses.
  - A $6 million decrease due to a gain on the sale of property in the current year in the APCo region.
- Asset Impairments and Other Related Charges increased $11 million due to the impairment of I&M’s Price River Coal reserves.
- Depreciation and Amortization expenses increased $13 million primarily due to:
  - A $25 million increase in depreciation primarily related to interim rate increases in Oklahoma.
  - A $12 million increase due to a higher depreciable base.

  These increases were partially offset by the following:
  - An $11 million decrease in the amortization of capitalized software due to prior year retirements.
  - A $6 million decrease in amortization related to the advanced metering infrastructure projects in Oklahoma.
  - A $5 million revision in I&M’s nuclear asset retirement obligation (ARO) estimate, which has a corresponding increase in Other Operation and Maintenance expenses above.
  - A $4 million decrease in the ARO expense due to steam plant retirements in 2015.
- Taxes Other Than Income Taxes increased $7 million primarily due to an increase in property taxes as a result of increased property investment.
- Allowance for Equity Funds Used During Construction decreased $10 million primarily due to the completion of environmental projects at SWEPCo.
- Interest Expense increased $8 million primarily due to higher long-term debt balances in I&M.
- Income Tax Expense decreased $18 million primarily due to the recording of federal and state income tax adjustments and other book/tax differences which are accounted for on a flow-through basis, partially offset by an increase in pretax book income.

24

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
	(in millions)			
Revenues	$1,275.6	$1,188.6	$3,468.5	$3,519.4
Purchased Electricity	253.6	228.2	662.2	919.5
Amortization of Generation Deferrals	66.1	55.4	173.0	122.2
Gross Margin	955.9	905.0	2,633.3	2,477.7
Other Operation and Maintenance	357.9	347.9	1,008.2	955.5
Depreciation and Amortization	181.4	197.6	505.0	535.7
Taxes Other Than Income Taxes	132.0	122.3	373.0	362.2
Operating Income	284.6	237.2	747.1	624.3
Interest and Investment Income	1.0	1.4	4.3	4.7
Carrying Costs Income (Expense)	0.9	(1.6)	4.0	10.0
Allowance for Equity Funds Used During Construction	2.2	3.6	10.6	11.3
Interest Expense	(63.2)	(68.7)	(195.8)	(206.3)
Income Before Income Tax Expense	225.5	171.9	570.2	444.0
Income Tax Expense	70.0	58.9	182.1	156.2
Net Income	155.5	113.0	388.1	287.8
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$155.5	$113.0	$388.1	$287.8

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
	(in millions of KWhs)			
Retail:				
Residential	8,325	7,590	20,575	20,486
Commercial	7,287	7,033	19,676	19,320
Industrial	5,518	5,665	16,522	16,754
Miscellaneous	187	194	528	532
Total Retail (a)	21,317	20,482	57,301	57,092
Wholesale (b)	654	497	1,389	1,460
Total KWhs	21,971	20,979	58,690	58,552

(a) Represents energy delivered to distribution customers.
(b) Primarily 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 the eastern region have a larger effect on revenues than changes in the 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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in degree days)			
Eastern Region				
Actual – Heating (a)	—	—	1,929	2,575
Normal – Heating (b)	7	6	2,110	2,073
Actual – Cooling (c)	900	620	1,209	970
Normal – Cooling (b)	664	666	956	956
Western Region				
Actual – Heating (a)	—	—	123	320
Normal – Heating (b)	—	—	198	192
Actual – Cooling (d)	1,534	1,476	2,619	2,380
Normal – Cooling (b)	1,358	1,355	2,384	2,381

(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.

Third Quarter of 2016 Compared to Third Quarter of 2015
Reconciliation of Third Quarter of 2015 to Third Quarter of 2016
Earnings Attributable to AEP Common Shareholders from
Transmission and Distribution Utilities
(in millions)

Third Quarter of 2015	$113.0
Changes in Gross Margin:	
Retail Margins	54.3
Off-system Sales	8.6
Transmission Revenues	12.4
Other Revenues	(24.4)
Total Change in Gross Margin	50.9
Changes in Expenses and Other:	
Other Operation and Maintenance	(10.0)
Depreciation and Amortization	16.2
Taxes Other Than Income Taxes	(9.7)
Interest and Investment Income	(0.4)
Carrying Costs Income	2.5
Allowance for Equity Funds Used During Construction	(1.4)
Interest Expense	5.5
Total Change in Expenses and Other	2.7
Income Tax Expense	(11.1)
Third Quarter of 2016	$155.5

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 $54 million primarily due to the following:
  - An $18 million increase in collections of the Ohio PIRR as a result of the June 2016 PUCO order.
  - A $4 million increase in revenues associated with the Ohio Distribution Investment Rider (DIR).
  - A $10 million increase in Ohio transmission and PJM revenues, partially offset by a corresponding decrease in other expense items below.
  - A $9 million increase in the Universal Service Fund (USF) rider in Ohio. This increase in Retail Margins is primarily offset by an increase in Other Operation and Maintenance expenses below.
  - A $4 million increase in TCC and TNC revenues primarily due to the recovery of ERCOT transmission expenses, offset in Other Operation and Maintenance expenses below.
  - A $4 million increase in TCC and TNC revenues primarily due to the recovery of distribution expenses.
  - A $3 million increase in Texas weather-normalized margins in the residential class.
- Margins from Off-system Sales increased $9 million primarily due to prior year losses from a power contract with OVEC.
- Transmission Revenues increased $12 million primarily due to the following:
  - A $9 million increase primarily due to increased transmission investment in ERCOT.
  - A $4 million increase in Ohio primarily due to increased investment in the transmission system.
- Other Revenues decreased $24 million primarily due to the following:

- A $29 million decrease due to a decrease in Texas securitization revenue due to the final maturity of the first Texas securitization bond, offset in Depreciation and Amortization and other expense items below.

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

- Other Operation and Maintenance expenses increased $10 million primarily due to the following:
  - A $22 million increase in recoverable expenses, primarily including gridSMART®, ERCOT and PJM expenses, currently fully recovered in rate recovery riders/trackers.
  - A $9 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in Retail Margins above.

  These increases were partially offset by:
  - A $14 million decrease in employee and AEPSC related expenses.
  - A $4 million decrease in vegetation management expenses.
- Depreciation and Amortization expenses decreased $16 million primarily due to the following:
  - A $25 million decrease in TCC's securitization transition asset due to the final maturity of TCC's first securitization bond, which is offset in Other Revenues above.
  - A $5 million decrease in recoverable gridSMART® depreciation expenses in Ohio.

  These decreases were partially offset by:
  - A $6 million increase in Ohio DIR recoveries.
  - A $6 million increase in depreciation expense primarily due to an increase in depreciable base of transmission and distribution assets.
- Taxes Other Than Income Taxes increased $10 million primarily due to the following:
  - A $5 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.
  - A $4 million increase in state excise taxes in Ohio due to an increase in metered KWh.
- Interest Expense decreased $6 million due to maturities of debt in Ohio and Texas.
- Income Tax Expense increased $11 million primarily due to an increase in pretax book income partially offset by the recording of federal income tax adjustments and other book/tax differences which are accounted for on a flow-through basis.

28

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015
Reconciliation of Nine Months Ended September 30, 2015 to
Nine Months Ended September 30, 2016
Earnings Attributable to AEP Common Shareholders from
Transmission and Distribution Utilities
(in millions)

Nine Months Ended September 30, 2015	$287.8
Changes in Gross Margin:	
Retail Margins	235.6
Off-system Sales	(9.1)
Transmission Revenues	(10.8)
Other Revenues	(60.1)
Total Change in Gross Margin	155.6
Changes in Expenses and Other:	
Other Operation and Maintenance	(52.7)
Depreciation and Amortization	30.7
Taxes Other Than Income Taxes	(10.8)
Interest and Investment Income	(0.4)
Carrying Costs Income	(6.0)
Allowance for Equity Funds Used During Construction	(0.7)
Interest Expense	10.5
Total Change in Expenses and Other	(29.4)
Income Tax Expense	(25.9)
Nine Months Ended September 30, 2016	$388.1

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

- Retail Margins increased $236 million primarily due to the following:
- A $128 million increase in Ohio transmission and PJM revenues primarily due to the energy supplied as a result of the Ohio auction and a regulatory change which resulted in revenues collected through a non-bypassable transmission rider, partially offset by a corresponding decrease in Transmission Revenues below.
- A $31 million increase in Ohio riders such as Universal Service Fund (USF) and gridSMART®. This increase in Retail Margins is primarily offset by an increase in Other Operation and Maintenance expenses below.
- A $21 million increase due to a reversal of a regulatory provision resulting from a favorable court decision in Ohio.
- An $18 million increase in collections of the Ohio PIRR as a result of the June 2016 PUCO order.
- A $16 million increase in revenues associated with the Ohio DIR.
- An $18 million increase in Texas weather-normalized margins primarily in the residential class.
- A $13 million increase in TCC and TNC revenues primarily due to the recovery of ERCOT transmission expenses, offset in Other Operation and Maintenance expenses below.
- A $10 million increase in carrying charges due to the collection of carrying costs on Ohio deferred capacity charges beginning June 2015.
- A $4 million increase in TCC and TNC revenues primarily due to the recovery of distribution expenses.

These increases were partially offset by:

- A $16 million decrease in revenues associated with the recovery of 2012 storm costs under the Ohio 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.
- A $6 million decrease in weather-related usage in Texas.

- Margins from Off-system Sales decreased $9 million primarily due to increased losses from a power contract with OVEC.
- Transmission Revenues decreased $11 million primarily due to the following:
- A $55 million decrease in NITS revenue primarily 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, partially offset by a corresponding increase in Retail Margins above.

This decrease was partially offset by:

- A $27 million increase primarily due to increased transmission investment in ERCOT.
- A $19 million increase in Ohio due to a settlement recorded in 2015, a decrease in amortization of the formula rate true-up and the recording of the current year formula rate true-up in 2016.
- Other Revenues decreased $60 million primarily due to a decrease in Texas securitization revenue as a result of the final maturity of the first Texas securitization bond, offset in Depreciation and Amortization and other expense items below.

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

- Other Operation and Maintenance expenses increased $53 million primarily due to the following:
- An $88 million increase in recoverable expenses, primarily including PJM expenses and gridSMART® expenses, currently fully recovered in rate recovery riders/trackers.
- A $15 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in Retail Margins above.

These increases were partially offset by:

- A $14 million decrease due to the completion of the Ohio amortization of 2012 deferred storm expenses. This decrease was offset by a corresponding decrease in Retail Margins above.
- A $13 million decrease in distribution expenses primarily related to prior year asset inspections.
- A $9 million decrease in vegetation management expenses.
- A $6 million decrease due to a PUCO ordered contribution to the Ohio Growth Fund recorded in 2015.
- Depreciation and Amortization expenses decreased $31 million primarily due to the following:
- A $49 million decrease in TCC's securitization transition asset due to the final maturity of TCC's first securitization bond, which is offset in Other Revenues above.
- An $11 million decrease in recoverable gridSMART® depreciation expenses in Ohio.

These decreases were partially offset by:

- A $17 million increase in depreciation expense primarily due to an increase in depreciable base of transmission and distribution assets.
- An $8 million increase due to recoveries of Ohio transmission cost rider carrying costs. This increase was offset by a corresponding increase in Retail Margins above.
- A $6 million increase in amortization expenses for the collection of carrying costs on Ohio deferred capacity charges beginning June 2015. This increase was offset by a corresponding increase in Retail Margins above.
- Taxes Other Than Income Taxes increased $11 million primarily due to increased property taxes resulting from additional investments in transmission and distribution assets and higher tax rates.
- Carrying Costs Income decreased $6 million primarily due to the following:
- A $10 million decrease due to the collection of carrying costs on Ohio deferred capacity charges beginning June 2015.

This decrease was partially offset by:

- A $4 million increase primarily due to an unfavorable prior period adjustment related to gridSMART® capital carrying charges in Ohio.
- Interest Expense decreased $11 million primarily due to:
- An $11 million decrease in TCC's securitization transition assets due to the final maturity of the first Texas securitization bond. This decrease was offset by a corresponding decrease in Other Revenues above.
- A $7 million decrease due to the maturity of an OPCo senior unsecured note in June 2016.
- A $3 million decrease in recoverable gridSMART® interest expenses in Ohio.

These decreases were partially offset by the following:

- An $11 million increase due to issuances of senior unsecured notes by TCC and TNC.
- Income Tax Expense increased $26 million primarily due to an increase in pretax book income partially offset by the recording of state and federal income tax adjustments and other book/tax differences which are accounted for on a flow-through basis.

AEP TRANSMISSION HOLDCO

AEP Transmission Holdco	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
	(in millions)			
Transmission Revenues	$132.4	$87.5	$382.7	$244.9
Other Operation and Maintenance	12.2	11.0	32.7	26.8
Depreciation and Amortization	17.1	11.7	48.4	30.3
Taxes Other Than Income Taxes	22.7	16.4	65.7	49.2
Operating Income	80.4	48.4	235.9	138.6
Carrying Costs Expense	—	—	(0.2)	(0.1)
Allowance for Equity Funds Used During Construction	13.5	13.6	39.8	39.6
Interest Expense	(12.2)	(9.9)	(35.4)	(27.0)
Income Before Income Tax Expense and Equity Earnings	81.7	52.1	240.1	151.1
Income Tax Expense	35.2	23.4	103.2	66.2
Equity Earnings of Unconsolidated Subsidiaries	23.0	17.2	72.6	62.8
Net Income	69.5	45.9	209.5	147.7
Net Income Attributable to Noncontrolling Interests	0.5	0.3	2.0	1.1
Earnings Attributable to AEP Common Shareholders	$69.0	$45.6	$207.5	$146.6

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

	September 30, 2016	September 30, 2015
	(in millions)	
Net Plant in Service	$3,242.4	$2,252.6
CWIP	1,565.8	1,298.5

Third Quarter of 2016 Compared to Third Quarter of 2015

Reconciliation of Third Quarter of 2015 to Third Quarter of 2016
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Third Quarter of 2015	$45.6
Changes in Transmission Revenues:	
Transmission Revenues	44.9
Total Change in Transmission Revenues	44.9
Changes in Expenses and Other:	
Other Operation and Maintenance	(1.2)
Depreciation and Amortization	(5.4)
Taxes Other Than Income Taxes	(6.3)
Allowance for Equity Funds Used During Construction	(0.1)
Interest Expense	(2.3)
Total Change in Expenses and Other	(15.3)
Income Tax Expense	(11.8)
Equity Earnings	5.8
Net Income Attributable to Noncontrolling Interests	(0.2)
Third Quarter of 2016	$69.0

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 $45 million due to formula rate increases driven by continued investment in transmission assets and the related increases in recoverable operating expenses.

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

- Depreciation and Amortization expenses increased $5 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $6 million primarily due to increased property taxes as a result of additional transmission investment.
- Income Tax Expense increased $12 million primarily due to an increase in pretax book income.
- Equity Earnings increased $6 million primarily due to increased transmission investment by ETT.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015

Reconciliation of Nine Months Ended September 30, 2015 to Nine Months Ended September 30, 2016
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Nine Months Ended September 30, 2015	$146.6
Changes in Transmission Revenues:	
Transmission Revenues	137.8
Total Change in Transmission Revenues	137.8
Changes in Expenses and Other:	
Other Operation and Maintenance	(5.9)
Depreciation and Amortization	(18.1)
Taxes Other Than Income Taxes	(16.5)
Carrying Costs Expense	(0.1)
Allowance for Equity Funds Used During Construction	0.2
Interest Expense	(8.4)
Total Change in Expenses and Other	(48.8)
Income Tax Expense	(37.0)
Equity Earnings	9.8
Net Income Attributable to Noncontrolling Interests	(0.9)
Nine Months Ended September 30, 2016	$207.5

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 $138 million primarily due to the following:
- A $110 million increase due to formula rate increases driven by continued investment in transmission assets and the related increases in recoverable operating expenses.
- A $28 million increase due to AEPTCo annual formula rate true-up adjustments.

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

- Other Operation and Maintenance expenses increased $6 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $18 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $17 million primarily due to increased property taxes as a result of additional transmission investment.
- Interest Expense increased $8 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $37 million primarily due to an increase in pretax book income.
- Equity Earnings increased $10 million primarily due to increased transmission investment by ETT.

GENERATION & MARKETING

Generation & Marketing	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
	(in millions)			
Revenues	$859.4	$836.0	$2,291.2	$2,806.7
Fuel, Purchased Electricity and Other	567.4	564.4	1,490.6	1,771.3
Gross Margin	292.0	271.6	800.6	1,035.4
Other Operation and Maintenance	95.8	60.2	290.2	276.6
Asset Impairments and Other Related Charges	2,254.4	—	2,254.4	—
Depreciation and Amortization	50.5	50.9	149.8	151.8
Taxes Other Than Income Taxes	8.7	10.5	29.0	30.4
Operating Income (Loss)	(2,117.4)	150.0	(1,922.8)	576.6
Other Income	0.3	0.6	1.2	2.2
Interest Expense	(9.5)	(10.4)	(27.1)	(31.0)
Income (Loss) Before Income Tax Expense	(2,126.6)	140.2	(1,948.7)	547.8
Income Tax Expense (Credit)	(757.4)	48.6	(699.9)	187.5
Net Income (Loss)	(1,369.2)	91.6	(1,248.8)	360.3
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings (Loss) Attributable to AEP Common Shareholders	$(1,369.2)	$91.6	$(1,248.8)	$360.3

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
	(in millions of MWhs)			
Fuel Type:				
Coal	8	7	19	23
Natural Gas	4	3	11	10
Wind	—	1	—	1
Total MWhs	12	11	30	34

35

Third Quarter of 2016 Compared to Third Quarter of 2015
Reconciliation of Third Quarter of 2015 to Third Quarter of 2016
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Third Quarter of 2015	$91.6
Changes in Gross Margin:	
Generation	(2.8)
Retail, Trading and Marketing	25.0
Other	(1.8)
Total Change in Gross Margin	20.4
Changes in Expenses and Other:	
Other Operation and Maintenance	(35.6)
Asset Impairments and Other Related Charges	(2,254.4)
Depreciation and Amortization	0.4
Taxes Other Than Income Taxes	1.8
Other Income	(0.3)
Interest Expense	0.9
Total Change in Expenses and Other	(2,287.2)
Income Tax Expense	806.0
Third Quarter of 2016	$(1,369.2)

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

- Retail, Trading and Marketing increased $25 million primarily due to the impact of favorable wholesale trading and marketing performance and higher retail margins and volume.

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

- Other Operation and Maintenance expenses increased $36 million primarily due to the prior year sale of certain assets and revision of the related asset retirement obligations.
- Asset Impairments and Other Related Charges increased $2.3 billion due to an asset impairment of certain merchant generation assets.
- Income Tax Expense decreased $806 million primarily due to reduced pretax book income as a result of the impairment of certain merchant generation assets.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015
Reconciliation of Nine Months Ended September 30, 2015
to Nine Months Ended September 30, 2016
Earnings Attributable to AEP Common Shareholders from
Generation & Marketing
(in millions)

Nine Months Ended September 30, 2015	$360.3
Changes in Gross Margin:	
Generation	(227.5)
Retail, Trading and Marketing	(3.0)
Other	(4.3)
Total Change in Gross Margin	(234.8)
Changes in Expenses and Other:	
Other Operation and Maintenance	(13.6)
Asset Impairments and Other Related Charges	(2,254.4)
Depreciation and Amortization	2.0
Taxes Other Than Income Taxes	1.4
Other Income	(1.0)
Interest Expense	3.9
Total Change in Expenses and Other	(2,261.7)
Income Tax Expense	887.4
Nine Months Ended September 30, 2016	$(1,248.8)

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 $228 million primarily due to lower capacity revenues due to plant retirements and the transition of the Ohio Standard Service offer to full market pricing and a decrease in wholesale energy prices partially offset by favorable hedging activity.

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

- Other Operation and Maintenance expenses increased $14 million primarily due to the prior year sale of certain assets and revision of the related asset retirement obligations, partially offset by a decrease in maintenance due to plant retirements in June 2015.
- Asset Impairments and Other Related Charges increased $2.3 billion due to an asset impairment of certain merchant generation assets.
- Interest Expense decreased $4 million primarily due to decreased long-term debt balances.
- Income Tax Expense decreased $887 million primarily due to reduced pretax book income as a result of the impairment of certain merchant generation assets.

CORPORATE AND OTHER

Third Quarter of 2016 Compared to Third Quarter of 2015

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from a loss of $6 million in 2015 to a gain of $36 million in 2016 primarily due to the reversal of capital loss valuation allowances related to the pending sale of certain merchant generation assets as well as tax return adjustments related to the prior year disposition of AEP’s commercial barging operations. This was partly offset by decreased income from the discontinued operations of AEP’s commercial barging operations which was sold in November 2015.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from income of $3 million in 2015 to income of $61 million in 2016 primarily due to the reversal of capital loss valuation allowances related to the settlement of a 2011 audit issue with the IRS and the impact of the pending sale of certain merchant generation assets as well as 2015 tax return adjustments related to the disposition of AEP’s commercial barging operations. This was partly offset by charges related to the final accounting of the disposition of AEP’s commercial barging operations and decreased income from the discontinued operations of AEP’s commercial barging operations which was sold in November 2015.

AEP SYSTEM INCOME TAXES

Third Quarter of 2016 Compared to Third Quarter of 2015

Income Tax Expense decreased $810 million primarily due to reduced pretax book income as a result of the impairment of certain merchant generation assets and the reversal of capital loss valuation allowances related to the pending sale of certain merchant generation assets as well as 2015 tax return adjustments related to the disposition of AEP’s commercial barging operations.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015

Income Tax Expense decreased $961 million primarily due to reduced pretax book income as a result of the impairment of certain merchant generation assets and the reversal of capital loss valuation allowances related to the pending sale of certain merchant generation assets and the settlement of a 2011 audit issue with the IRS as well as 2015 tax return adjustments related to the disposition of AEP’s commercial barging operations.

FINANCIAL CONDITION

AEP measures financial condition by the strength of its balance sheet and the liquidity provided by its cash flows.

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	September 30, 2016				December 31, 2015		
	(dollars in millions)						
Long-term Debt, including amounts due within one year	$19,839.5	(a)	51.3	%	$19,572.7	51.1	%
Short-term Debt	1,478.3		3.8		800.0	2.1	
Total Debt	21,317.8	(a)	55.1		20,372.7	53.2	

AEP Common Equity	17,321.9	44.8	17,891.7	46.8
Noncontrolling Interests	21.1	0.1	13.2	—
Total Debt and Equity Capitalization	$38,660.8	100.0%	$38,277.6	100.0%

(a) Amounts include debt related to the Lawrenceburg Plant that has been classified as Liabilities Held for Sale on the balance sheet. See “Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)” section of Note 6 for additional information.

AEP's ratio of debt-to-total capital changed primarily due to a decrease in common equity as a result of the impairment of certain merchant generation assets.

Liquidity

Liquidity, or access to cash, is an important factor in determining AEP's financial stability. Management believes AEP has adequate liquidity under its existing credit facilities. As of September 30, 2016, AEP had $3.5 billion in aggregate credit facility commitments to support its operations. Additional liquidity is available from cash from operations and a receivables securitization agreement. Management is committed to maintaining adequate liquidity. AEP generally uses short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-leaseback or leasing agreements or common stock.

Commercial Paper Credit Facilities

AEP manages liquidity by maintaining adequate external financing commitments. As of September 30, 2016, available liquidity was approximately $3 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 3,000.0	June 2021
Revolving Credit Facility	500.0	June 2018
Total	3,500.0	
Cash and Cash Equivalents	212.2	
Total Liquidity Sources	3,712.2	
Less: AEP Commercial Paper Outstanding	728.3	
Net Available Liquidity	$ 2,983.9	

AEP has two credit facilities totaling $3.5 billion to support its commercial paper program. The $3 billion credit facility allows management to issue letters of credit in an amount up to $1.2 billion.

AEP uses its commercial paper program to meet the short-term borrowing needs of its subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds certain 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 nine months of 2016 was $1.5 billion. The weighted-average interest rate for AEP's commercial paper during 2016 was 0.77%.

Other Credit Facilities

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit under four uncommitted facilities totaling $300 million. As of September 30, 2016, the maximum future payment for letters of credit issued under the uncommitted facilities was $147 million with maturities ranging from October 2016 to September 2017.

Securitized Accounts Receivable

AEP’s receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement expires in June 2018.

Debt Covenants and Borrowing Limitations

AEP’s credit agreements contain certain covenants and require it to maintain a 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 AEP’s credit agreements. Debt as defined in the revolving credit agreements excludes securitization bonds and debt of AEP Credit. As of September 30, 2016, this contractually-defined percentage was 52.7%. Nonperformance under these covenants could result in an event of default under these credit agreements. In addition, the acceleration of AEP’s payment obligations, or the obligations of certain of AEP’s 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 AEP’s non-exchange traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under AEP’s non-exchange traded commodity contracts would not cause an event of default under its 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 AEP manages its borrowings to stay within those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.59 per share in October 2016. Future dividends may vary depending upon AEP’s profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Parent’s income primarily derives from common stock equity in the earnings of its utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends.

Management does not believe these restrictions related to AEP’s various financing arrangements and regulatory requirements will have any significant impact on its ability to access cash to meet the payment of dividends on its common stock.

Credit Ratings

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

CASH FLOW

AEP relies primarily on cash flows from operations, debt issuances and its existing cash and cash equivalents to fund its liquidity and investing activities. AEP’s investing and capital requirements are primarily capital expenditures, repaying of long-term debt and paying dividends to shareholders.

	Nine Months Ended September 30,	
	2016	2015

	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$176.4	$162.5
Net Cash Flows from Continuing Operating Activities	3,421.0	3,910.7
Net Cash Flows Used for Continuing Investing Activities	(3,428.7)	(3,248.4)
Net Cash Flows from (Used for) Continuing Financing Activities	46.0	(647.3)
Net Cash Flows from (Used for) Discontinued Operations	(2.5)	0.3
Net Increase in Cash and Cash Equivalents	35.8	15.3
Cash and Cash Equivalents at End of Period	$212.2	$177.8

40

AEP uses short-term debt, including commercial paper, as a bridge to long-term debt financing. The levels of borrowing may vary significantly due to the timing of long-term debt financings and the impact of fluctuations in cash flows.

Operating Activities

	Nine Months Ended September 30,	
	2016	2015
	(in millions)	
Income from Continuing Operations	$245.3	$1,563.4
Depreciation and Amortization	1,550.2	1,528.0
Deferred Income Taxes	(47.0)	528.6
Asset Impairments and Other Related Charges	2,264.9	—
Fuel, Materials and Supplies	11.6	193.8
Accrued Taxes, Net	(393.0)	(68.3)
Other	(211.0)	165.2
Net Cash Flows from Continuing Operating Activities	$3,421.0	$3,910.7

Net Cash Flows from Continuing Operating Activities were $3.4 billion in 2016 consisting primarily of Net Income of $245 million and $1.6 billion of noncash Depreciation and Amortization. AEP also had asset impairments of $2.3 billion during the third quarter of 2016. See Note 6 - Dispositions, Assets and Liabilities Held for Sale and Impairments for a complete discussion of asset impairments and other related charges. Accrued Taxes decreased primarily due to the impacts of bonus depreciation related to the Protecting Americans from Tax Hikes Act of 2015. Deferred Income Taxes decreased primarily due to the tax effect of the asset impairment partially offset by an increase in tax versus book temporary differences from operations, which includes provisions related to the Protecting Americans from Tax Hikes Act of 2015. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities.

Net Cash Flows from Continuing Operating Activities were $3.9 billion in 2015 consisting primarily of Net Income of $1.6 billion and $1.5 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 and plants retired during the second quarter of 2015.

Investing Activities

	Nine Months Ended September 30,	
	2016	2015
	(in millions)	
Construction Expenditures	$(3,387.0)	$(3,282.7)
Acquisitions of Nuclear Fuel	(127.6)	(53.3)
Other	85.9	87.6
Net Cash Flows Used for Continuing Investing Activities	$(3,428.7)	$(3,248.4)

Net Cash Flows Used for Continuing Investing Activities were $3.4 billion in 2016 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Net Cash Flows Used for Continuing Investing Activities were $3.2 billion in 2015 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Financing Activities

	Nine Months Ended September 30,	
	2016	2015
	(in millions)	
Issuance of Common Stock	$34.2	$67.9
Issuance of Debt, Net	930.3	235.7
Dividends Paid on Common Stock	(829.8)	(783.4)
Other	(88.7)	(167.5)
Net Cash Flows from (Used for) Continuing Financing Activities	$46.0	$(647.3)

Net Cash Flows from Continuing Financing Activities in 2016 were $46 million. AEP’s net debt issuances were $930 million. The net issuances included an increase in short-term borrowing of $678 million, issuances of $950 million of senior unsecured notes, $191 million of pollution control bonds and $430 million of other debt notes offset by retirements of $507 million of senior unsecured notes, $289 million of securitization bonds, $251 million of pollution control bonds and $261 million of other debt notes. AEP paid common stock dividends of $830 million. See Note 12 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows Used for Continuing Financing Activities in 2015 were $647 million. AEP’s net debt issuances were $236 million. The net issuances included issuances of $2.1 billion of senior unsecured notes, $140 million of pollution control bonds and $757 million of other debt notes offset by retirements of $907 million of senior unsecured notes, $308 million of securitization bonds, $229 million of pollution control bonds and $687 of other debt notes and a decrease in short term borrowing of $564 million. AEP paid common stock dividends of $783 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 $74 million. See Note 12 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

In October 2016, I&M retired $16 million of Notes Payable related to DCC Fuel.

OFF-BALANCE SHEET ARRANGEMENTS

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

	September 30,	December 31,
	2016	2015
	(in millions)	
Rockport Plant, Unit 2 Future Minimum Lease Payments	$960.1	$ 1,034.0
Railcars Maximum Potential Loss from Lease Agreement	18.1	18.1

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 2015 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2015 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in the “Cash Flow” section above.

42

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 2015 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

Long-Lived Assets

Nature of Estimates Required

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

Assumptions and Approach Used

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

Effect if Different Assumptions Used

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

ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncements Adopted During 2016

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 statements of income. 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. Management adopted ASU 2015-01 effective January 1, 2016.

The FASB issued ASU 2015-05 “Customer’s Accounting for Fees paid in a Cloud Computing Arrangement” providing 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 adopted ASU 2015-05 prospectively, effective January 1, 2016, with no impact on results of operations, financial position or cash flows.

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, determine 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 FASB deferred implementation of ASU 2014-09 under the terms in ASU 2015-14, “Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date.” The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted for annual periods beginning after December 15, 2016. Management is analyzing the impact of this new standard and the related ASUs that clarify guidance in the standard. At this time, management cannot estimate the impact of adoption on revenue or net income. Management plans to adopt ASU 2014-09 effective January 1, 2018.

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 does not expect the new standard to impact the Registrants’ results of operations, financial position or cash flows. Management plans to adopt ASU 2015-11 prospectively, effective January 1, 2017.

The FASB issued ASU 2016-01 “Recognition and Measurement of Financial Assets and Financial Liabilities” enhancing the reporting model for financial instruments. Under the new standard, equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) are required to be measured at fair value with changes in fair value recognized in net income. The new standard also amends disclosure requirements and requires separate presentation of financial assets and liabilities by measurement category and form of financial asset (that is, securities or loans and receivables) on the balance sheet or the accompanying notes to the financial statements. The amendments also clarify that an entity should evaluate the need for a valuation allowance on a deferred tax asset related to available-for-sale securities in combination with the entity's other deferred tax assets. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted. The amendments will be applied by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. 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 2016-01 effective January 1, 2018.

The FASB issued ASU 2016-02 “Accounting for Leases” increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheets and disclosing key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheets. Additionally, a capital lease will be known as a finance lease going forward. Leases with lease terms of 12 months or longer will be subject to the new requirements. Fundamentally, the criteria used to determine lease classification will remain the same, but will be more subjective under the new standard. The new accounting guidance is effective for annual periods beginning after December 15, 2018 with early adoption permitted. The guidance will be applied by means of a modified retrospective approach. The modified retrospective approach will require lessees and lessors to recognize and measure leases at the beginning of the earliest period presented as well as a number of optional practical expedients that entities may elect to apply. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption. Management expects the new standard to impact the Registrants’ financial position, but not the Registrants’ results of operations or cash flows. Management plans to adopt ASU 2016-02 effective January 1, 2019.

The FASB issued ASU 2016-09 “Compensation – Stock Compensation” simplifying the accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities and classification on the statements of cash flows. Under the new standard, all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) should be recognized as income tax expense or benefit on the statements of income. Under current GAAP, excess tax benefits are recognized in additional paid-in capital while tax deficiencies are recognized either as an offset to accumulated excess tax benefits, if any, or on the statements of income. The new accounting guidance is effective for annual periods beginning after December 15, 2016. Early adoption is permitted in any interim or annual period. Certain provisions require retrospective/modified retrospective transition while others are to be applied prospectively. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption. Management plans to adopt ASU 2016-09 effective January 1, 2017.

The FASB issued ASU 2016-13 “Measurement of Credit Losses on Financial Instruments” requiring an allowance to be recorded for all expected credit losses for financial assets. The allowance for credit losses is based on historical information, current conditions and reasonable and supportable forecasts. The new standard also makes revisions to the other than temporary impairment model for available-for-sale debt securities. Disclosures of credit quality indicators in relation to the amortized cost of financing receivables are further disaggregated by year of origination. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2019 with early adoption permitted for interim and annual periods beginning after December 15, 2018. The amendments will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. 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 2016-13 effective January 1, 2020.

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 operations and financial position that may result from any such future changes. The FASB is currently working on several projects including hedge accounting, consolidations and pension and postretirement benefits. 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

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

The Transmission and Distribution Utilities segment is exposed to energy procurement risk and interest rate risk.

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

Management employs risk management contracts including physical forward purchase-and-sale contracts and financial forward purchase-and-sale contracts. Management engages in risk management of power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. As a result, AEP is subject to price risk. The amount of risk taken is determined by the Commercial Operations, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors. AEPSC'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) 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, positions are modified 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, 2015:
MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2016

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
	(in millions)			
Total MTM Risk Management Contract Net Assets as of December 31, 2015	$8.6	$ 14.4	$ 143.2	$166.2
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(12.4)	3.5	(9.7)	(18.6)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	30.5	30.5
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	0.7	0.7
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	1.3	(63.7)	—	(62.4)
Total MTM Risk Management Contract Net Assets as of September 30, 2016	$(2.5)	$ (45.8)	$ 164.7	116.4
Commodity Cash Flow Hedge Contracts				(41.9)
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				(0.2)
Collateral Deposits				28.9
Total MTM Derivative Contract Net Assets as of September 30, 2016				$103.2

(a) Reflects fair value on primarily long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 9 – Derivatives and Hedging and Note 10 – Fair Value Measurements for additional information related to risk management contracts.

Credit Risk

Credit risk is limited in 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. Management uses 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.

AEP has risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, exposures change daily. As of September 30, 2016, credit exposure net of collateral to sub investment grade counterparties was approximately 7.1%, 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 September 30, 2016, the following table approximates AEP's 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	$751.8	$ 5.0	$ 746.8	3	$ 378.8
Split Rating	16.9	—	16.9	1	15.6
No External Ratings:					
Internal Investment Grade	113.2	—	113.2	2	57.3
Internal Noninvestment Grade	81.5	14.9	66.6	3	43.1
Total as of September 30, 2016	$963.4	$ 19.9	$ 943.5		

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

Value at Risk (VaR) Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates VaR, to measure AEP's 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 September 30, 2016, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

Management calculates the VaR for both a trading and non-trading portfolio. The trading portfolio consists primarily of contracts related to energy trading and marketing activities. The non-trading portfolio consists primarily of economic hedges of generation and retail supply activities. The following tables show the end, high, average and low market risk as measured by VaR for the periods indicated:

VaR Model
Trading Portfolio

Nine Months Ended September 30, 2016				Twelve Months Ended December 31, 2015			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$0.1	$1.1	$ 0.2	$0.1	$0.2	$0.9	$ 0.2	$0.1

VaR Model
Non-Trading Portfolio

Nine Months Ended September 30, 2016				Twelve Months Ended December 31, 2015			
End	High	Average	Low	End	High	Average	Low

(in millions)				(in millions)			
$0.9	$2.8	$ 0.9	$0.4	$1.1	$2.4	$ 0.9	$0.4

48

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

As the VaR calculation captures recent price movements, management also performs regular stress testing of the trading portfolio to understand AEP's exposure to extreme price movements. A historical-based method is employed 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. Management then researches the underlying positions, price movements and market events that created the most significant exposure and reports the findings to the Risk Executive Committee, Regulated Risk Committee, or Competitive Risk Committee as appropriate.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which 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 September 30, 2016 and December 31, 2015, the estimated EaR on AEP's debt portfolio for the following twelve months was $30 million and $25 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
For the Three and Nine Months Ended September 30, 2016 and 2015
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
REVENUES				
Vertically Integrated Utilities	$2,538.3	$ 2,435.8	$6,864.6	$ 7,081.8
Transmission and Distribution Utilities	1,245.4	1,163.6	3,398.9	3,377.9
Generation & Marketing	823.3	801.8	2,192.5	2,288.6
Other Revenues	45.2	30.2	134.0	90.2
TOTAL REVENUES	4,652.2	4,431.4	12,590.0	12,838.5
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	880.1	955.9	2,236.1	2,782.4
Purchased Electricity for Resale	774.0	730.8	2,134.6	2,050.0
Other Operation	771.1	689.9	2,150.7	1,954.6
Maintenance	286.3	311.5	854.4	923.1
Asset Impairments and Other Related Charges	2,264.9	—	2,264.9	—
Depreciation and Amortization	539.3	534.9	1,550.2	1,528.0
Taxes Other Than Income Taxes	264.4	248.2	767.9	733.3
TOTAL EXPENSES	5,780.1	3,471.2	11,958.8	9,971.4
OPERATING INCOME (LOSS)	(1,127.9)	960.2	631.2	2,867.1
Other Income (Expense):				
Interest and Investment Income	2.0	1.6	6.5	6.1
Carrying Costs Income	1.7	1.8	11.9	18.4
Allowance for Equity Funds Used During Construction	25.6	32.6	86.1	96.4
Interest Expense	(225.3)	(220.2)	(667.2)	(658.1)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (CREDIT) AND EQUITY EARNINGS	(1,323.9)	776.0	68.5	2,329.9
Income Tax Expense (Credit)	(534.5)	275.6	(134.0)	827.1
Equity Earnings of Unconsolidated Subsidiaries	25.2	11.4	42.8	60.6
INCOME (LOSS) FROM CONTINUING OPERATIONS	(764.2)	511.8	245.3	1,563.4
INCOME (LOSS) FROM DISCONTINUED OPERATIONS, NET OF TAX	—	7.8	(2.5)	18.2
NET INCOME (LOSS)	(764.2)	519.6	242.8	1,581.6
Net Income Attributable to Noncontrolling Interests	1.6	1.3	5.3	4.1

EARNINGS (LOSS) ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$(765.8)	$ 518.3	$237.5	$ 1,577.5
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	491,697,804	490,648,929	491,422,924	490,155,315
BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS	$(1.56)	$ 1.04	$0.49	$ 3.18
BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS	$—	$ 0.02	$(0.01)	$ 0.04
TOTAL BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$(1.56)	$ 1.06	$0.48	$ 3.22
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	491,813,854	490,800,335	491,596,864	490,411,020
DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS	$(1.56)	$ 1.04	$0.49	$ 3.18
DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS	$—	$ 0.02	$(0.01)	$ 0.04
TOTAL DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$(1.56)	$ 1.06	$0.48	$ 3.22
CASH DIVIDENDS DECLARED PER SHARE	$0.56	$ 0.53	$1.68	$ 1.59

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net Income (Loss)	$(764.2)	$519.6	$242.8	$1,581.6
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(15.4) and $(2.9) for the Three Months Ended September 30, 2016 and 2015, Respectively, and $(11.2) and $(5.8) for the Nine Months Ended September 30, 2016 and 2015, Respectively	(28.6)	(5.3)	(20.8)	(10.7)
Securities Available for Sale, Net of Tax of $0.3 and $(0.7) for the Three Months Ended September 30, 2016 and 2015, Respectively, and $1 and $(0.5) for the Nine Months Ended September 30, 2016 and 2015, Respectively	0.5	(1.3)	1.7	(1.0)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0.1 and $0.2 for the Three Months Ended September 30, 2016 and 2015, Respectively, and $0.2 and $0.5 for the Nine Months Ended September 30, 2016 and 2015, Respectively	0.2	0.3	0.4	0.9
TOTAL OTHER COMPREHENSIVE LOSS	(27.9)	(6.3)	(18.7)	(10.8)
TOTAL COMPREHENSIVE INCOME (LOSS)	(792.1)	513.3	224.1	1,570.8
Total Comprehensive Income Attributable to Noncontrolling Interests	1.6	1.3	5.3	4.1
TOTAL COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$(793.7)	$512.0	$218.8	$1,566.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock				Accumulated Other		
	Shares	Amount	Paid-in Capital	Retained Earnings	Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY - DECEMBER 31, 2014	509.7	$3,313.3	$6,203.4	$7,406.6	$ (103.1)	$ 4.3	$16,824.5
Issuance of Common Stock	1.4	9.1	58.8				67.9
Common Stock Dividends				(780.3)		(3.1)	(783.4)
Other Changes in Equity			19.6			5.0	24.6
Net Income				1,577.5		4.1	1,581.6
Other Comprehensive Loss					(10.8)		(10.8)
Pension and OPEB Adjustment Related to Mitchell Plant					5.1		5.1
TOTAL EQUITY - SEPTEMBER 30, 2015	511.1	$3,322.4	$6,281.8	$8,203.8	$ (108.8)	$ 10.3	$17,709.5
TOTAL EQUITY - DECEMBER 31, 2015	511.4	$3,324.0	$6,296.5	$8,398.3	$ (127.1)	$ 13.2	$17,904.9
Issuance of Common Stock	0.6	4.3	29.9				34.2
Common Stock Dividends				(826.4)		(3.4)	(829.8)
Other Changes in Equity			3.6			6.0	9.6
Net Income				237.5		5.3	242.8
Other Comprehensive Loss					(18.7)		(18.7)
TOTAL EQUITY - SEPTEMBER 30, 2016	512.0	$3,328.3	$6,330.0	$7,809.4	$ (145.8)	$ 21.1	$17,343.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2016 and December 31, 2015
(in millions)
(Unaudited)

	September 30, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$212.2	$ 176.4
Other Temporary Investments (September 30, 2016 and December 31, 2015 Amounts Include $270.5 and $376.6, Respectively, Related to Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, EIS and Sabine)	279.2	386.8
Accounts Receivable:		
Customers	628.4	615.9
Accrued Unbilled Revenues	166.7	31.2
Pledged Accounts Receivable – AEP Credit	1,065.5	940.3
Miscellaneous	59.9	82.1
Allowance for Uncollectible Accounts	(40.5)	(29.0)
Total Accounts Receivable	1,880.0	1,640.5
Fuel	468.0	600.8
Materials and Supplies	556.8	738.6
Risk Management Assets	110.8	134.4
Accrued Tax Benefits	214.9	58.9
Regulatory Asset for Under-Recovered Fuel Costs	107.4	115.2
Margin Deposits	56.5	107.3
Assets Held for Sale	1,915.3	—
Prepayments and Other Current Assets	148.1	113.5
TOTAL CURRENT ASSETS	5,949.2	4,072.4
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	19,684.2	25,559.8
Transmission	15,157.8	14,247.9
Distribution	18,639.0	18,046.9
Other Property, Plant and Equipment (September 30, 2016 and December 31, 2015 Amounts Include Coal Mining and Nuclear Fuel, December 31, 2015 Amount Includes 2016 Plant Retirements)	3,467.5	3,722.9
Construction Work in Progress	3,651.3	3,903.9
Total Property, Plant and Equipment	60,599.8	65,481.4
Accumulated Depreciation and Amortization	16,337.6	19,348.2
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	44,262.2	46,133.2
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,182.4	5,140.3
Securitized Assets	1,559.0	1,749.9
Spent Nuclear Fuel and Decommissioning Trusts	2,230.8	2,106.4

Goodwill	52.5	52.5
Long-term Risk Management Assets	311.7	321.8
Deferred Charges and Other Noncurrent Assets	1,894.2	2,106.6
TOTAL OTHER NONCURRENT ASSETS	11,230.6	11,477.5
TOTAL ASSETS	$61,442.0	$ 61,683.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2016 and December 31, 2015
(dollars in millions)
(Unaudited)

	September 30, 2016	December 31, 2015
CURRENT LIABILITIES		
Accounts Payable	$ 1,340.3	$ 1,418.0
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	750.0	675.0
Other Short-term Debt	728.3	125.0
Total Short-term Debt	1,478.3	800.0
Long-term Debt Due Within One Year (September 30, 2016 and December 31, 2015 Amounts Include $393.4 and $410.4, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Sabine)	2,384.8	1,831.8
Risk Management Liabilities	79.3	87.1
Customer Deposits	341.6	346.6
Accrued Taxes	666.2	979.1
Accrued Interest	230.2	226.9
Regulatory Liability for Over-Recovered Fuel Costs	7.9	113.9
Liabilities Held for Sale	231.0	—
Other Current Liabilities	1,019.8	1,305.1
TOTAL CURRENT LIABILITIES	7,779.4	7,108.5
NONCURRENT LIABILITIES		
Long-term Debt (September 30, 2016 and December 31, 2015 Amounts Include $1,727.6 and $1,971.4, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy and Sabine)	17,319.9	17,740.9
Long-term Risk Management Liabilities	240.0	179.1
Deferred Income Taxes	11,815.1	11,733.2
Regulatory Liabilities and Deferred Investment Tax Credits	3,887.5	3,736.1
Asset Retirement Obligations	1,858.0	1,806.5
Employee Benefits and Pension Obligations	497.0	583.3
Deferred Credits and Other Noncurrent Liabilities	702.1	890.6
TOTAL NONCURRENT LIABILITIES	36,319.6	36,669.7
TOTAL LIABILITIES	44,099.0	43,778.2
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
EQUITY		

Common Stock – Par Value – $6.50 Per Share:				
	2016	2015		
Shares Authorized	600,000,000	600,000,000		
Shares Issued	512,046,044	511,389,173		
(20,336,592 Shares were Held in Treasury as of September 30, 2016 and December 31, 2015)			3,328.3	3,324.0
Paid-in Capital			6,330.0	6,296.5
Retained Earnings			7,809.4	8,398.3
Accumulated Other Comprehensive Income (Loss)			(145.8)	(127.1)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			17,321.9	17,891.7
Noncontrolling Interests			21.1	13.2
TOTAL EQUITY			17,343.0	17,904.9
TOTAL LIABILITIES AND EQUITY			$61,442.0	$ 61,683.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

54

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2016	2015
OPERATING ACTIVITIES		
Net Income	$242.8	$1,581.6
Income (Loss) from Discontinued Operations	(2.5)	18.2
Income from Continuing Operations	245.3	1,563.4
Adjustments to Reconcile Income from Continuing Operations to Net Cash Flows from Continuing Operating Activities:		
Depreciation and Amortization	1,550.2	1,528.0
Deferred Income Taxes	(47.0)	528.6
Asset Impairments and Other Related Charges	2,264.9	—
Carrying Costs Income	(11.9)	(18.4)
Allowance for Equity Funds Used During Construction	(86.1)	(96.4)
Mark-to-Market of Risk Management Contracts	56.6	17.7
Amortization of Nuclear Fuel	109.7	101.6
Pension Contributions to Qualified Plan Trust	(84.8)	(91.8)
Property Taxes	288.3	247.1
Deferred Fuel Over/Under-Recovery, Net	(28.5)	93.3
Deferral of Ohio Capacity Costs, Net	108.8	35.0
Change in Other Noncurrent Assets	(231.5)	(114.3)
Change in Other Noncurrent Liabilities	41.3	8.9
Changes in Certain Components of Continuing Working Capital:		
Accounts Receivable, Net	(240.8)	(17.5)
Fuel, Materials and Supplies	11.6	193.8
Accounts Payable	47.8	(13.3)
Accrued Taxes, Net	(393.0)	(68.3)
Other Current Assets	31.5	10.5
Other Current Liabilities	(211.4)	2.8
Net Cash Flows from Continuing Operating Activities	3,421.0	3,910.7
INVESTING ACTIVITIES		
Construction Expenditures	(3,387.0)	(3,282.7)
Change in Other Temporary Investments, Net	109.2	80.8
Purchases of Investment Securities	(2,454.5)	(1,489.4)
Sales of Investment Securities	2,427.0	1,437.3
Acquisitions of Nuclear Fuel	(127.6)	(53.3)
Other Investing Activities	4.2	58.9
Net Cash Flows Used for Continuing Investing Activities	(3,428.7)	(3,248.4)
FINANCING ACTIVITIES		
Issuance of Common Stock	34.2	67.9
Issuance of Long-term Debt	1,559.6	2,931.1

Change in Short-term Debt, Net	678.3	(564.0)
Retirement of Long-term Debt	(1,307.6)	(2,131.4)
Make Whole Premium on Extinguishment of Long-term Debt	—	(92.7)
Principal Payments for Capital Lease Obligations	(81.9)	(73.9)
Dividends Paid on Common Stock	(829.8)	(783.4)
Other Financing Activities	(6.8)	(0.9)
Net Cash Flows from (Used for) Continuing Financing Activities	46.0	(647.3)
Net Cash Flows from (Used for) Discontinued Operating Activities	(2.5)	10.1
Net Cash Flows from Discontinued Investing Activities	—	2.5
Net Cash Flows Used for Discontinued Financing Activities	—	(12.3)
Net Increase in Cash and Cash Equivalents	35.8	15.3
Cash and Cash Equivalents at Beginning of Period	176.4	162.5
Cash and Cash Equivalents at End of Period	$212.2	$177.8
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$637.0	$639.1
Net Cash Paid for Income Taxes	32.2	115.6
Noncash Acquisitions Under Capital Leases	65.8	96.9
Construction Expenditures Included in Current Liabilities as of September 30,	604.8	579.4
Construction Expenditures Included in Noncurrent Liabilities as of September 30,	—	66.3
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	0.3	31.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

55

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

56

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions of KWhs)			
Retail:				
Residential	2,845	2,599	8,743	9,039
Commercial	1,823	1,744	5,125	5,161
Industrial	2,391	2,493	7,022	7,520
Miscellaneous	217	205	637	633
Total Retail	7,276	7,041	21,527	22,353
Wholesale	1,029	681	2,413	2,335
Total KWhs	8,305	7,722	23,940	24,688

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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in degree days)			
Actual - Heating (a)	—	—	1,433	1,735
Normal - Heating (b)	2	3	1,437	1,415
Actual - Cooling (c)	1,049	804	1,437	1,275
Normal - Cooling (b)	808	809	1,177	1,175

(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) Cooling degree days are calculated on a 65 degree temperature base.

57

Third Quarter of 2016 Compared to Third Quarter of 2015
Reconciliation of Third Quarter of 2015 to Third Quarter of 2016
Net Income
(in millions)

Third Quarter of 2015	$ 74.6
Changes in Gross Margin:	
Retail Margins	54.4
Off-system Sales	1.5
Transmission Revenues	2.6
Other Revenues	1.9
Total Change in Gross Margin	60.4
Changes in Expenses and Other:	
Other Operation and Maintenance	(12.1)
Depreciation and Amortization	(1.8)
Carrying Costs Income	(0.1)
Allowance for Equity Funds Used During Construction	1.1
Interest Expense	0.2
Total Change in Expenses and Other	(12.7)
Income Tax Expense	(18.2)
Third Quarter of 2016	$ 104.1

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 $54 million primarily due to the following:
  - A $34 million increase primarily due to increases in rates in West Virginia and Virginia. Of these rate increases, $27 million relates to riders/trackers which have corresponding increases in other expense items below.
  - A $24 million increase in weather-related usage primarily due to a 30% increase in cooling degree days.

  These increases were partially offset by:
  - An $8 million decrease in weather-normalized margin in all retail classes.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $12 million primarily due to the following:
  - A $17 million increase associated with amortization of deferred transmission costs in accordance with the Virginia Transmission Rate Adjustment Clause effective January 2016. This increase in expense is offset within Retail Margins above.
  - A $7 million increase in PJM transmission expenses. This increase in expense is offset within Retail Margins above.

  These increases were partially offset by:
  - A $6 million decrease in employee-related expenses.
  - A $2 million decrease in storm-related expenses.
  - A $2 million decrease in distribution expenses primarily due to prior year vegetation pilot program.
- Income Tax Expense increased $18 million primarily due to an increase in pretax book income.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015
Reconciliation of Nine Months Ended September 30, 2015 to
Nine Months Ended September 30, 2016
Net Income
(in millions)

Nine Months Ended September 30, 2015	$275.4
Changes in Gross Margin:	
Retail Margins	93.0
Transmission Revenues	(14.1)
Other Revenues	3.5
Total Change in Gross Margin	82.4
Changes in Expenses and Other:	
Other Operation and Maintenance	(54.3)
Depreciation and Amortization	2.7
Taxes Other Than Income Taxes	(0.8)
Interest Income	(0.4)
Carrying Costs Income	(0.6)
Allowance for Equity Funds Used During Construction	(1.2)
Interest Expense	4.9
Total Change in Expenses and Other	(49.7)
Income Tax Expense	(4.3)
Nine Months Ended September 30, 2016	$303.8

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 $93 million primarily due to the following:
- A $111 million increase primarily due to increases in rates in West Virginia and Virginia, which includes recognition of deferred billing in West Virginia as approved by the WVPSC in June 2016. This increase is partially offset by a prior year adjustment affected by the amended Virginia law that has an impact on biennial reviews. Of these rate increases, $81 million relate to riders/trackers which have corresponding increases in other expense items below.

This increase was partially offset by:

- A $20 million decrease in weather-normalized margin primarily in the industrial class.
- A $10 million decrease in weather-related usage due to a 17% decrease in heating degree days offset with a 13% increase in cooling degree days.
- Transmission Revenues decreased $14 million primarily due to lower Network Integrated Transmission Service revenues.

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

- Other Operation and Maintenance expenses increased $54 million primarily due to the following:
  - A $41 million increase associated with amortization of deferred transmission costs in accordance with the Virginia Transmission Rate Adjustment Clause effective January 2016. This increase in expense is offset within Retail Margins above.
  - An $8 million increase in distribution expenses primarily due to vegetation management. This increase in expense is offset within Retail Margins above.
  - A $5 million increase in amortization of previously deferred West Virginia storm expenses as approved in the May 2015 West Virginia base case order. This increase in expense is offset within Retail Margins above.
  - A $4 million increase in storm-related expenses.

  These increases were partially offset by:
  - A $6 million gain on the sale of property in the current year.
- Depreciation and Amortization expenses decreased $3 million primarily due to the following:
  - A $7 million decrease in asset retirement obligations and plant amortizations due to plant retirements in 2015.
  - A $2 million decrease due to prior year amortization of Virginia environmental deferrals. This decrease in expense is offset within Retail Margins above.

  These decreases were partially offset by:
  - A $6 million increase due to a higher depreciable base.
- Interest Expense decreased $5 million primarily due to lower interest rates on long-term debt.
- Income Tax Expense increased $4 million primarily due to an increase in pretax book income and by the recording of federal income tax adjustments, partially offset by other book/tax differences which are accounted for on a flow-through basis and the regulatory accounting treatment of state income taxes.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2016	2015	2016	2015
REVENUES				
Electric Generation, Transmission and Distribution	$739.0	$685.3	$2,153.3	$2,184.9
Sales to AEP Affiliates	36.4	39.3	109.0	115.7
Other Revenues	2.8	2.9	9.4	7.9
TOTAL REVENUES	778.2	727.5	2,271.7	2,308.5
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	190.1	188.5	494.1	595.3
Purchased Electricity for Resale	69.2	80.5	240.9	258.9
Other Operation	117.6	101.8	349.4	311.6
Maintenance	66.8	70.5	196.3	179.8
Depreciation and Amortization	98.1	96.3	290.0	292.7
Taxes Other Than Income Taxes	32.0	32.0	93.9	93.1
TOTAL EXPENSES	573.8	569.6	1,664.6	1,731.4
OPERATING INCOME	204.4	157.9	607.1	577.1
Other Income (Expense):				
Interest Income	0.3	0.3	0.8	1.2
Carrying Costs Income	—	0.1	0.2	0.8
Allowance for Equity Funds Used During Construction	4.5	3.4	9.1	10.3
Interest Expense	(46.4)	(46.6)	(140.7)	(145.6)
INCOME BEFORE INCOME TAX EXPENSE	162.8	115.1	476.5	443.8
Income Tax Expense	58.7	40.5	172.7	168.4
NET INCOME	$104.1	$74.6	$303.8	$275.4

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

See Condensed Notes to Condensed

Financial Statements of Registrants beginning on page 113.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net Income	$104.1	$74.6	$303.8	$275.4
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended September 30, 2016 and 2015, Respectively, and $(0.3) and $0 for the Nine Months Ended September 30, 2016 and 2015, Respectively	(0.2)	(0.2)	(0.6)	(0.1)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $(0.2) for the Three Months Ended September 30, 2016 and 2015, Respectively, and $(0.5) and $(0.7) for the Nine Months Ended September 30, 2016 and 2015, Respectively	(0.3)	(0.5)	(1.0)	(1.4)
TOTAL OTHER COMPREHENSIVE LOSS	(0.5)	(0.7)	(1.6)	(1.5)
TOTAL COMPREHENSIVE INCOME	$103.6	$73.9	$302.2	$273.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

62

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$ 260.4	$ 1,809.6	$ 1,291.9	$ 5.0	$ 3,366.9
Common Stock Dividends			(181.3)		(181.3)
Net Income			275.4		275.4
Other Comprehensive Loss				(1.5)	(1.5)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2015	$ 260.4	$ 1,809.6	$ 1,386.0	$ 3.5	$ 3,459.5
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2015	$ 260.4	$ 1,828.7	$ 1,388.7	$ (2.8)	$ 3,475.0
Common Stock Dividends			(225.0)		(225.0)
Net Income			303.8		303.8
Other Comprehensive Loss				(1.6)	(1.6)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2016	$ 260.4	$ 1,828.7	$ 1,467.5	$ (4.4)	$ 3,552.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2016 and December 31, 2015
(in millions)
(Unaudited)

	September 30, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$3.3	$ 2.8
Restricted Cash for Securitized Funding	7.8	14.8
Advances to Affiliates	24.4	25.6
Accounts Receivable:		
Customers	115.4	120.9
Affiliated Companies	54.3	51.2
Accrued Unbilled Revenues	42.3	17.9
Miscellaneous	1.1	2.2
Allowance for Uncollectible Accounts	(4.7)	(4.3)
Total Accounts Receivable	208.4	187.9
Fuel	124.8	119.3
Materials and Supplies	100.0	127.0
Risk Management Assets – Nonaffiliated	3.2	14.7
Risk Management Assets – Affiliated	—	0.9
Accrued Tax Benefits	16.0	30.6
Regulatory Asset for Under-Recovered Fuel Costs	71.6	86.9
Prepayments and Other Current Assets	17.4	17.4
TOTAL CURRENT ASSETS	576.9	627.9
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,319.5	6,200.8
Transmission	2,555.3	2,408.1
Distribution	3,519.2	3,402.5
Other Property, Plant and Equipment	368.7	345.5
Construction Work in Progress	481.9	475.1
Total Property, Plant and Equipment	13,244.6	12,832.0
Accumulated Depreciation and Amortization	3,598.1	3,407.6
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	9,646.5	9,424.4
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,123.0	1,154.2
Securitized Assets	311.0	328.0
Long-term Risk Management Assets – Nonaffiliated	0.2	0.1
Deferred Charges and Other Noncurrent Assets	110.7	113.7
TOTAL OTHER NONCURRENT ASSETS	1,544.9	1,596.0
TOTAL ASSETS	$11,768.3	$ 11,648.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2016 and December 31, 2015
(Unaudited)

	September 30, 2016	December 31, 2015
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$84.1	$ 181.0
Accounts Payable:		
General	174.1	196.5
Affiliated Companies	74.8	67.7
Long-term Debt Due Within One Year – Nonaffiliated	503.1	318.0
Risk Management Liabilities – Nonaffiliated	10.7	4.8
Customer Deposits	81.8	83.9
Accrued Taxes	51.8	79.5
Accrued Interest	63.3	40.6
Other Current Liabilities	127.1	153.4
TOTAL CURRENT LIABILITIES	1,170.8	1,125.4
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,530.0	3,612.7
Long-term Risk Management Liabilities – Nonaffiliated	0.3	0.1
Deferred Income Taxes	2,632.9	2,527.0
Regulatory Liabilities and Deferred Investment Tax Credits	628.8	637.1
Asset Retirement Obligations	91.2	98.9
Employee Benefits and Pension Obligations	103.0	114.4
Deferred Credits and Other Noncurrent Liabilities	59.1	57.7
TOTAL NONCURRENT LIABILITIES	7,045.3	7,047.9
TOTAL LIABILITIES	8,216.1	8,173.3
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	260.4	260.4
Paid-in Capital	1,828.7	1,828.7
Retained Earnings	1,467.5	1,388.7
Accumulated Other Comprehensive Income (Loss)	(4.4)	(2.8)
TOTAL COMMON SHAREHOLDER'S EQUITY	3,552.2	3,475.0
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$11,768.3	$ 11,648.3

See
Condensed

Notes to Condensed Financial Statements of Registrants beginning on page 113.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Nine Months Ended September 30,					
	2016			2015		
OPERATING ACTIVITIES						
Net Income	$	303.8		$	275.4	
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:						
Depreciation and Amortization	290.0			292.7		
Deferred Income Taxes	100.9			179.1		
Carrying Costs Income	(0.2		)	(0.8		)
Allowance for Equity Funds Used During Construction	(9.1		)	(10.3		)
Mark-to-Market of Risk Management Contracts	18.4			(5.9		)
Pension Contributions to Qualified Plan Trust	(8.8		)	(10.0		)
Property Taxes	29.2			28.0		
Deferred Fuel Over/Under-Recovery, Net	19.0			(1.7		)
Change in Other Noncurrent Assets	(5.1		)	(33.2		)
Change in Other Noncurrent Liabilities	(23.0		)	(26.7		)
Changes in Certain Components of Working Capital:						
Accounts Receivable, Net	(20.5		)	28.8		
Fuel, Materials and Supplies	(1.2		)	31.4		
Accounts Payable	4.9			2.7		
Accrued Taxes, Net	(13.9		)	(75.3		)
Other Current Assets	(0.2		)	(2.6		)
Other Current Liabilities	(4.1		)	15.4		
Net Cash Flows from Operating Activities	680.1			687.0		
INVESTING ACTIVITIES						
Construction Expenditures	(472.7		)	(456.7		)
Change in Restricted Cash for Securitized Funding	7.0			8.2		
Change in Advances to Affiliates, Net	1.2			25.0		
Other Investing Activities	10.6			10.6		
	(453.9		)	(412.9		)

Net Cash Flows Used for Investing Activities		
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	314.1	726.3
Change in Advances from Affiliates, Net	(96.9)	35.2
Retirement of Long-term Debt – Nonaffiliated	(213.6)	(672.5)
Retirement of Long-term Debt – Affiliated	—	(86.0)
Make Whole Premium on Extinguishment of Long-term Debt – Nonaffiliated	—	(92.7)
Principal Payments for Capital Lease Obligations	(4.7)	(3.8)
Dividends Paid on Common Stock	(225.0)	(181.3)
Other Financing Activities	0.4	0.5
Net Cash Flows Used for Financing Activities	(225.7)	(274.3)
Net Increase (Decrease) in Cash and Cash Equivalents	0.5	(0.2)
Cash and Cash Equivalents at Beginning of Period	2.8	2.6
Cash and Cash Equivalents at End of Period	$ 3.3	$ 2.4
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 113.2	$ 128.4
Net Cash Paid for Income Taxes	55.8	33.7
Noncash Acquisitions Under Capital Leases	2.1	2.3
Construction Expenditures Included in Current Liabilities as of September 30,	66.8	81.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page

113.

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

67

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions of KWhs)			
Retail:				
Residential	1,619	1,441	4,344	4,311
Commercial	1,405	1,342	3,780	3,744
Industrial	1,996	1,972	5,876	5,712
Miscellaneous	15	15	50	50
Total Retail	5,035	4,770	14,050	13,817
Wholesale	2,613	2,649	7,038	8,732
Total KWhs	7,648	7,419	21,088	22,549

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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in degree days)			
Actual - Heating (a)	—	—	2,196	2,931
Normal - Heating (b)	10	10	2,449	2,413
Actual - Cooling (c)	741	530	1,011	796
Normal - Cooling (b)	571	574	835	836

(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) Cooling degree days are calculated on a 65 degree temperature base.

Third Quarter of 2016 Compared to Third Quarter of 2015

Reconciliation of Third Quarter of 2015 to Third Quarter of 2016	
Net Income	
(in millions)	
Third Quarter of 2015	$56.6
Changes in Gross Margin:	
Retail Margins	30.7
Off-system Sales	(0.5)
Transmission Revenues	1.7
Other Revenues	(2.9)
Total Change in Gross Margin	29.0
Changes in Expenses and Other:	
Other Operation and Maintenance	10.2
Asset Impairments and Other Related Charges	(10.5)
Depreciation and Amortization	0.2
Taxes Other Than Income Taxes	(0.9)
Other Income	1.8
Interest Expense	(3.6)
Total Change in Expenses and Other	(2.8)
Income Tax Expense	(7.4)
Third Quarter of 2016	$75.4

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 $31 million primarily due to the following:
- A $17 million increase from rate proceedings in the Indiana service territory. The increase in retail margins relating to riders has corresponding increases in other items below.
- A $15 million increase in weather-related usage due to a 40% increase in cooling degree days.
- An $8 million increase in weather-normalized margins.

These increases were partially offset by:

- A $6 million decrease in fuel recovery from wholesale customers due to the timing of fuel recovery in 2015 primarily as a result of an extended forced outage at Cook Plant, Unit 1.
- A $2 million decrease due to PJM charges not currently recovered in rate recovery riders/trackers.
- 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 activities discussed below.

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

- Other Operation and Maintenance expenses decreased $10 million primarily due to the following:
  - A $10 million decrease in nuclear expenses primarily due to an extended forced outage at Cook Plant, Unit 1 related to the emergency diesel generator repair in 2015.
  - A $4 million decrease in general and administrative expenses.
  - A $4 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 $3 million decrease in steam generation maintenance expenses at Rockport in addition to the retirement of Tanners Creek Plant in May 2015.

  These decreases were partially offset by:
  - A $5 million increase in distribution expenses primarily due to increased forestry expenses.
  - A $2 million increase in transmission expenses primarily due to increased PJM expenses.
  - A $2 million increase in accretion due to the impact of a revision in the nuclear Asset Retirement Obligation (ARO) estimate on decommissioning expense. This increase has a corresponding offset in Depreciation and Amortization expenses.
- Asset Impairments and Other Related Charges increased $11 million due to the impairment of I&M’s Price River coal reserves.
- Interest Expense increased $4 million primarily due to higher long-term debt balances.
- Income Tax Expense increased $8 million primarily due to an increase in pretax book income.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015

Reconciliation of Nine Months Ended September 30,
2015 to Nine Months Ended September 30, 2016
Net Income
(in millions)

Nine Months Ended September 30, 2015	$ 179.9
Changes in Gross Margin:	
Retail Margins	32.0
Off-system Sales	(9.8)
Transmission Revenues	(6.2)
Other Revenues	(4.9)
Total Change in Gross Margin	11.1
Changes in Expenses and Other:	
Other Operation and Maintenance	19.7
Asset Impairments and Other Related Charges	(10.5)
Depreciation and Amortization	7.0
Taxes Other Than Income Taxes	(4.5)
Other Income	3.7
Interest Expense	(7.4)
Total Change in Expenses and Other	8.0
Income Tax Expense	2.4
Nine Months Ended September 30, 2016	$ 201.4

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 $32 million primarily due to the following:
  - A $29 million increase from rate proceedings in the Indiana service territory. The increase in retail margins relating to riders has corresponding increases in other items below.
  - A $21 million increase in weather-normalized margins.

  These increases were partially offset by:
  - A $12 million decrease in FERC municipal and cooperative revenues due to annual formula rate adjustments offset by increased formula rate changes.
  - A $3 million decrease in fuel recovery from wholesale customers due to the timing of fuel recovery in 2015 primarily as a result of an extended forced outage at Cook Plant, Unit 1.
- Margins from Off-system Sales decreased $10 million primarily due to lower market prices and decreased sales volumes.
- Transmission Revenues decreased $6 million primarily due to a lower transmission formula rate true-up than in the prior year, partially offset by higher Network Integration Transmission Service revenues.
- Other Revenues decreased $5 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 activities discussed below.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $20 million primarily due to the following:
  - A $26 million decrease in nuclear expenses primarily due to an extended forced outage at Cook Plant, Unit 1 for the emergency diesel generator repair of $13 million, in addition to a low pressure turbine inspection of $7 million at Cook Plant, Unit 2.
  - An $8 million decrease due to the retirement of Tanners Creek Plant in May 2015.
  - A $6 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 $5 million decrease primarily due to Rockport environmental compliance work performed in 2015.

  These decreases were partially offset by:
  - An $8 million increase in distribution expenses primarily due to increased forestry expenses.
  - A $7 million increase in transmission expenses primarily due to increased PJM expenses.
  - A $6 million increase due to the reduction of an environmental liability in 2015.
  - A $5 million increase in accretion due to the impact of a revision in the nuclear ARO estimate on decommissioning expense. This increase has a corresponding offset in Depreciation and Amortization expenses below.
- Asset Impairments and Other Related Charges increased $11 million due to the impairment of I&M’s Price River coal reserves.
- Depreciation and Amortization expenses decreased $7 million primarily due to the retirement of Tanners Creek Plant in May 2015 and a revision in the nuclear ARO estimate, partially offset by higher depreciable base.
- Taxes Other Than Income Taxes increased $5 million primarily due to property taxes.
- Other Income increased $4 million primarily due to a $3 million increase in Life Cycle Management carrying charges and $1 million increase in AFUDC equity accrued on nuclear fuel for the Cook Plant.
- Interest Expense increased $7 million primarily due to higher long-term debt balances.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2016	2015	2016	2015
REVENUES				
Electric Generation, Transmission and Distribution	$574.7	$536.2	$1,570.8	$1,617.5
Sales to AEP Affiliates	3.9	9.6	22.4	16.6
Other Revenues – Affiliated	15.6	21.7	46.3	62.2
Other Revenues – Nonaffiliated	3.4	0.8	13.2	2.6
TOTAL REVENUES	597.6	568.3	1,652.7	1,698.9
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	91.3	90.5	236.8	264.4
Purchased Electricity for Resale	43.7	41.5	134.3	147.7
Purchased Electricity from AEP Affiliates	64.5	67.2	165.9	182.2
Other Operation	138.9	141.0	413.9	407.3
Maintenance	45.7	53.8	134.6	160.9
Asset Impairments and Other Related Charges	10.5	—	10.5	—
Depreciation and Amortization	49.1	49.3	143.2	150.2
Taxes Other Than Income Taxes	22.5	21.6	71.5	67.0
TOTAL EXPENSES	466.2	464.9	1,310.7	1,379.7
OPERATING INCOME	131.4	103.4	342.0	319.2
Other Income (Expense):				
Interest Income	1.7	1.9	9.1	7.2
Allowance for Equity Funds Used During Construction	4.1	2.1	10.9	9.1
Interest Expense	(26.7)	(23.1)	(76.3)	(68.9)
INCOME BEFORE INCOME TAX EXPENSE	110.5	84.3	285.7	266.6
Income Tax Expense	35.1	27.7	84.3	86.7
NET INCOME	$75.4	$56.6	$201.4	$179.9

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2016	2015	2016	2015
Net Income	$75.4	$56.6	$201.4	$179.9
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.1 and $0.1 for the Three Months Ended September 30, 2016 and 2015, Respectively, and $0.5 and $0.4 for the Nine Months Ended September 30, 2016 and 2015, Respectively	0.3	0.3	1.0	0.8
TOTAL COMPREHENSIVE INCOME	$75.7	$56.9	$202.4	$180.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

74

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$ 56.6	$ 980.9	$ 930.8	$ (14.3)	$ 1,954.0
Common Stock Dividends			(90.0)		(90.0)
Net Income			179.9		179.9
Other Comprehensive Income				0.8	0.8
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2015	$ 56.6	$ 980.9	$ 1,020.7	$ (13.5)	$ 2,044.7
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2015	$ 56.6	$ 980.9	$ 1,015.6	$ (16.7)	$ 2,036.4
Common Stock Dividends			(93.8)		(93.8)
Net Income			201.4		201.4
Other Comprehensive Income				1.0	1.0
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2016	$ 56.6	$ 980.9	$ 1,123.2	$ (15.7)	$ 2,145.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2016 and December 31, 2015
(in millions)
(Unaudited)

	September 30, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1.6	$ 1.1
Advances to Affiliates	12.4	11.7
Accounts Receivable:		
Customers	46.3	43.9
Affiliated Companies	47.6	68.7
Accrued Unbilled Revenues	2.2	0.1
Miscellaneous	0.9	2.6
Allowance for Uncollectible Accounts	(0.1)	(0.1)
Total Accounts Receivable	96.9	115.2
Fuel	48.6	46.5
Materials and Supplies	156.2	185.9
Risk Management Assets – Nonaffiliated	5.2	10.6
Risk Management Assets – Affiliated	—	1.7
Accrued Tax Benefits	26.5	40.5
Prepayments and Other Current Assets	50.1	42.1
TOTAL CURRENT ASSETS	397.5	455.3
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	3,996.3	3,841.7
Transmission	1,437.7	1,406.9
Distribution	1,866.7	1,790.8
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	623.8	662.3
Construction Work in Progress	607.9	519.8
Total Property, Plant and Equipment	8,532.4	8,221.5
Accumulated Depreciation, Depletion and Amortization	3,063.9	3,018.0
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,468.5	5,203.5
OTHER NONCURRENT ASSETS		
Regulatory Assets	837.6	804.3
Spent Nuclear Fuel and Decommissioning Trusts	2,230.8	2,106.4
Long-term Risk Management Assets – Nonaffiliated	0.2	—
Deferred Charges and Other Noncurrent Assets	136.6	140.9
TOTAL OTHER NONCURRENT ASSETS	3,205.2	3,051.6
TOTAL ASSETS	$ 9,071.2	$ 8,710.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2016 and December 31, 2015
(dollars in millions)
(Unaudited)

	September 30, 2016	December 31, 2015
CURRENT LIABILITIES		
Advances from Affiliates	$26.3	$ 294.3
Accounts Payable:		
General	140.2	201.0
Affiliated Companies	61.9	61.8
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2016 and December 31, 2015 Amounts Include $97.8 and $84.6, Respectively, Related to DCC Fuel)	176.1	162.9
Risk Management Liabilities – Nonaffiliated	1.3	6.3
Customer Deposits	34.2	35.7
Accrued Taxes	43.7	74.2
Accrued Interest	11.8	26.2
Obligations Under Capital Leases	8.7	32.8
Other Current Liabilities	131.6	142.1
TOTAL CURRENT LIABILITIES	635.8	1,037.3
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,231.3	1,837.1
Long-term Risk Management Liabilities – Nonaffiliated	0.2	1.6
Deferred Income Taxes	1,510.9	1,361.5
Regulatory Liabilities and Deferred Investment Tax Credits	1,148.6	1,076.2
Asset Retirement Obligations	1,291.1	1,240.9
Deferred Credits and Other Noncurrent Liabilities	108.3	119.4
TOTAL NONCURRENT LIABILITIES	6,290.4	5,636.7
TOTAL LIABILITIES	6,926.2	6,674.0
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	56.6	56.6
Paid-in Capital	980.9	980.9
Retained Earnings	1,123.2	1,015.6
Accumulated Other Comprehensive Income (Loss)	(15.7)	(16.7)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,145.0	2,036.4
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$9,071.2	$ 8,710.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2016	2015
OPERATING ACTIVITIES		
Net Income	$ 201.4	$ 179.9
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	143.2	150.2
Deferred Income Taxes	116.2	38.3
Asset Impairments and Other Related Charges	10.5	—
Deferral of Incremental Nuclear Refueling Outage Expenses, Net	(17.4)	(0.1)
Allowance for Equity Funds Used During Construction	(10.9)	(9.1)
Mark-to-Market of Risk Management Contracts	0.5	12.9
Amortization of Nuclear Fuel	109.7	101.6
Pension Contribution to Qualified Plan Trust	(12.7)	(14.6)
Deferred Fuel Over/Under-Recovery, Net	6.1	(16.1)
Change in Other Noncurrent Assets	—	26.4
Change in Other Noncurrent Liabilities	30.0	9.2
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	17.0	5.5
Fuel, Materials and Supplies	(1.1)	29.6
Accounts Payable	(17.9)	(14.0)
Accrued Taxes, Net	(16.5)	4.6
Other Current Assets	6.7	7.0
Other Current Liabilities	(27.8)	(9.3)
Net Cash Flows from Operating Activities	537.0	502.0
INVESTING ACTIVITIES		
Construction Expenditures	(405.1)	(337.0)
Change in Advances to Affiliates, Net	(0.7)	—

Purchases of Investment Securities	(2,452.9)	(1,479.1)
Sales of Investment Securities	2,427.0	1,437.3
Acquisitions of Nuclear Fuel	(127.6)	(53.3)
Other Investing Activities	7.8	9.0
Net Cash Flows Used for Investing Activities	(551.5)	(423.1)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	482.7	210.7
Change in Advances from Affiliates, Net	(268.0)	8.5
Retirement of Long-term Debt – Nonaffiliated	(76.8)	(178.5)
Principal Payments for Capital Lease Obligations	(29.8)	(29.9)
Dividends Paid on Common Stock	(93.8)	(90.0)
Other Financing Activities	0.7	0.6
Net Cash Flows from (Used for) Financing Activities	15.0	(78.6)
Net Increase in Cash and Cash Equivalents	0.5	0.3
Cash and Cash Equivalents at Beginning of Period	1.1	1.0
Cash and Cash Equivalents at End of Period	$ 1.6	$ 1.3
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 85.6	$ 77.5
Net Cash Paid (Received) for Income Taxes	(36.0)	17.2
Noncash Acquisitions Under Capital Leases	16.8	2.0
Construction Expenditures Included in Current Liabilities as of September 30,	83.4	51.6
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	0.3	31.1
Expected Reimbursement for Capital Cost of Spent Nuclear Fuel Dry Cask Storage	0.1	2.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

OHIO POWER COMPANY AND SUBSIDIARIES

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions of KWhs)			
Retail:				
Residential	4,380	3,788	11,209	11,249
Commercial	4,114	3,929	11,158	11,074
Industrial	3,610	3,711	10,671	11,081
Miscellaneous	27	28	89	88
Total Retail (a)	12,131	11,456	33,127	33,492
Wholesale (b)	654	497	1,389	1,460
Total KWhs	12,785	11,953	34,516	34,952

(a) Represents energy delivered to distribution customers.
(b) Primarily 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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in degree days)			
Actual - Heating (a)	—	—	1,929	2,575
Normal - Heating (b)	7	6	2,110	2,073
Actual - Cooling (c)	900	620	1,209	970
Normal - Cooling (b)	664	666	956	956

(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) Cooling degree days are calculated on a 65 degree temperature base.

80

Third Quarter of 2016 Compared to Third Quarter of 2015
Reconciliation of Third Quarter of 2015 to Third Quarter of 2016
Net Income
(in millions)

Third Quarter of 2015	$71.6
Changes in Gross Margin:	
Retail Margins	41.7
Off-system Sales	9.4
Transmission Revenues	3.6
Other Revenues	3.2
Total Change in Gross Margin	57.9
Changes in Expenses and Other:	
Other Operation and Maintenance	(13.4)
Depreciation and Amortization	(5.7)
Taxes Other Than Income Taxes	(8.1)
Interest Income	(0.5)
Carrying Costs Income	2.5
Allowance for Equity Funds Used During Construction	(1.9)
Interest Expense	5.4
Total Change in Expenses and Other	(21.7)
Income Tax Expense	(7.9)
Third Quarter of 2016	$99.9

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 $42 million primarily due to the following:
  - An $18 million increase in collections of the PIRR as a result of the June 2016 PUCO order.
  - A $10 million increase in transmission and PJM revenues, partially offset by a corresponding decrease in other expense items below.
  - A $9 million increase in the Universal Service Fund (USF) rider. This increase was offset by an increase in Other Operation and Maintenance expenses below.
  - A $4 million increase in revenues associated with the Distribution Investment Rider (DIR).
- Margins from Off-system Sales increased $9 million primarily due to prior year losses from a power contract with OVEC.
- Transmission Revenues increased $4 million primarily due to an increased investment in the transmission system.
- Other Revenues increased $3 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 increased $13 million primarily due to the following:
  - A $9 million increase in recoverable gridSMART® expenses.
  - A $9 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in Retail Margins above.
  - A $3 million increase in recoverable PJM expenses.

  These increases were partially offset by:
  - A $9 million decrease in employee-related expenses.
- Depreciation and Amortization expenses increased $6 million primarily due to the following:
  - A $6 million increase in DIR recoveries.
  - A $2 million increase in depreciation expense primarily due to an increase in depreciable base of transmission and distribution assets.
  - A $1 million increase due to recoveries of transmission cost rider carrying costs. The increase was offset by a corresponding increase in Retail Margins above.

  These increases were partially offset by:
  - A $5 million decrease in recoverable gridSMART® depreciation expenses.
- Taxes Other Than Income Taxes increased $8 million primarily due to the following:
  - A $5 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.
  - A $3 million increase in state excise taxes due to an increase in metered KWh.
- Carrying Costs Income increased $3 million primarily due to an unfavorable prior period adjustment related to gridSMART® capital carrying charges.
- Interest Expense decreased $5 million primarily due to the maturity of a senior unsecured note in June 2016.
- Income Tax Expense increased $8 million primarily due to an increase in pretax book income partially offset by the recording of federal income tax adjustments and by other book/tax differences which are accounted for on a flow-through basis.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015

Reconciliation of Nine Months Ended September 30, 2015 to
Nine Months Ended September 30, 2016
Net Income
(in millions)

Nine Months Ended September 30, 2015	$184.7
Changes in Gross Margin:	
Retail Margins	207.2
Off-system Sales	(6.2)
Transmission Revenues	(36.8)
Other Revenues	0.9
Total Change in Gross Margin	165.1
Changes in Expenses and Other:	
Other Operation and Maintenance	(62.3)
Depreciation and Amortization	(10.4)
Taxes Other Than Income Taxes	(8.5)
Interest Income	(1.3)
Carrying Costs Income	(6.0)
Allowance for Equity Funds Used During Construction	(3.3)
Interest Expense	8.6
Total Change in Expenses and Other	(83.2)
Income Tax Expense	(21.9)
Nine Months Ended September 30, 2016	$244.7

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 $207 million primarily due to the following:
- A $128 million increase in transmission and PJM revenues primarily due to the energy supplied as a result of the Ohio auction and a regulatory change which resulted in revenues collected through a non-bypassable transmission rider, partially offset by a corresponding decrease in Transmission Revenues below.
- A $31 million increase in various riders such as USF, Energy Efficiency/Peak Demand Reduction Cost Recovery and gridSMART®. This increase is primarily offset by an increase in Other Operation and Maintenance expenses below.
- A $21 million increase due to a reversal of a regulatory provision resulting from a favorable court decision.
- An $18 million increase in collections of the PIRR as a result of the June 2016 PUCO order.
- A $16 million increase in revenues associated with the DIR.
- A $10 million increase in carrying charges due to the collection of carrying costs on deferred capacity charges beginning June 2015.

These increases were partially offset by:

- A $16 million decrease in revenues associated with the recovery of 2012 storm costs under 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.
- Margins from Off-system Sales decreased $6 million primarily due to increased losses from a power contract with OVEC.

- Transmission Revenues decreased $37 million primarily due to the following:
  - A $55 million decrease in NITS revenue primarily 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, partially offset by a corresponding increase in Retail Margins above.

  This decrease was partially offset by:
  - A $19 million increase due to a settlement recorded in 2015, a decrease in amortization of the formula rate true-up and the recording of the current year formula rate true-up in 2016.

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

- Other Operation and Maintenance expenses increased $62 million primarily due to the following:
- A $46 million increase in recoverable PJM expenses.
- A $25 million increase in recoverable gridSMART® expenses.
- A $15 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in Retail Margins above.

These increases were partially offset by:

- A $14 million decrease due to the completion of the amortization of 2012 deferred storm expenses in April 2015. This decrease was offset by a corresponding decrease in Retail Margins above.
- A $6 million decrease due to a PUCO ordered contribution to the Ohio Growth Fund recorded in 2015.
- A $5 million decrease in employee-related expenses.
- Depreciation and Amortization expenses increased $10 million primarily due to the following:
- An $8 million increase due to recoveries of transmission cost rider carrying costs. The increase was offset by a corresponding increase in Retail Margins above.
- A $6 million increase in amortization expenses for the collection of carrying costs on deferred capacity charges beginning June 2015. This increase was offset by a corresponding increase in Retail Margins above.
- A $6 million increase in depreciation expense primarily due to an increase in depreciable base of transmission and distribution assets.

These increases were partially offset by:

- An $11 million decrease in recoverable gridSMART® depreciation expenses.
- Taxes Other Than Income Taxes increased $9 million primarily due to additional investments in transmission and distribution assets and higher tax rates.
- Carrying Costs Income decreased $6 million primarily due to the following:
- A $10 million decrease due to the collection of carrying costs on deferred capacity charges beginning June 2015.

This decrease was partially offset by:

- A $4 million increase primarily due to an unfavorable prior period adjustment related to gridSMART® capital carrying charges.
- Interest Expense decreased $9 million primarily due to the following:
- A $7 million decrease due to the maturity of a senior unsecured note in June 2016.
- A $3 million decrease in recoverable gridSMART® interest expenses.
- Income Tax Expense increased $22 million primarily due to an increase in pretax book income partially offset by the recording of federal income tax adjustments and by other book/tax differences which are accounted for on a flow-through basis.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2016	2015	2016	2015
REVENUES				
Electricity, Transmission and Distribution	$864.4	$775.9	$2,349.2	$2,320.4
Sales to AEP Affiliates	5.5	4.4	11.7	79.7
Other Revenues	1.4	2.0	4.8	6.4
TOTAL REVENUES	871.3	782.3	2,365.7	2,406.5
EXPENSES				
Purchased Electricity for Resale	203.4	173.1	516.1	431.6
Purchased Electricity from AEP Affiliates	35.9	45.8	121.4	462.6
Amortization of Generation Deferrals	66.1	55.4	173.0	122.2
Other Operation	184.2	170.2	525.9	446.8
Maintenance	38.8	39.4	104.4	121.2
Depreciation and Amortization	69.4	63.7	189.0	178.6
Taxes Other Than Income Taxes	101.9	93.8	291.7	283.2
TOTAL EXPENSES	699.7	641.4	1,921.5	2,046.2
OPERATING INCOME	171.6	140.9	444.2	360.3
Other Income (Expense):				
Interest Income	0.7	1.2	3.0	4.3
Carrying Costs Income (Expense)	0.9	(1.6)	4.0	10.0
Allowance for Equity Funds Used During Construction	0.3	2.2	3.7	7.0
Interest Expense	(27.2)	(32.6)	(87.7)	(96.3)
INCOME BEFORE INCOME TAX EXPENSE	146.3	110.1	367.2	285.3
Income Tax Expense	46.4	38.5	122.5	100.6
NET INCOME	$99.9	$71.6	$244.7	$184.7

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

See Condensed Notes to Condensed

Financial Statements of Registrants beginning on page 113.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net Income	$99.9	$71.6	$244.7	$184.7
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(0.1) and $(0.2) for the Three Months Ended September 30, 2016 and 2015, Respectively, and $(0.5) and $(0.6) for the Nine Months Ended September 30, 2016 and 2015, Respectively	(0.2)	(0.3)	(1.0)	(1.0)
TOTAL COMPREHENSIVE INCOME	$99.7	$71.3	$243.7	$183.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$ 321.2	$ 838.8	$ 814.6	$ 5.6	$ 1,980.2
Common Stock Dividends			(156.3)		(156.3)
Net Income			184.7		184.7
Other Comprehensive Loss				(1.0)	(1.0)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2015	$ 321.2	$ 838.8	$ 843.0	$ 4.6	$ 2,007.6
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2015	$ 321.2	$ 838.8	$ 822.3	$ 4.3	$ 1,986.6
Common Stock Dividends			(150.0)		(150.0)
Net Income			244.7		244.7
Other Comprehensive Loss				(1.0)	(1.0)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2016	$ 321.2	$ 838.8	$ 917.0	$ 3.3	$ 2,080.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2016 and December 31, 2015
(in millions)
(Unaudited)

	September 30, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$4.0	$ 3.1
Restricted Cash for Securitized Funding	16.1	27.7
Advances to Affiliates	0.2	331.1
Accounts Receivable:		
Customers	13.8	46.4
Affiliated Companies	54.1	64.3
Accrued Unbilled Revenues	35.1	1.4
Miscellaneous	0.7	0.4
Allowance for Uncollectible Accounts	(0.2)	(0.2)
Total Accounts Receivable	103.5	112.3
Materials and Supplies	48.8	61.5
Emission Allowances	18.3	24.6
Accrued Tax Benefits	11.5	1.8
Prepayments and Other Current Assets	16.3	11.1
TOTAL CURRENT ASSETS	218.7	573.2
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	2,287.3	2,235.6
Distribution	4,401.7	4,287.7
Other Property, Plant and Equipment	436.7	408.2
Construction Work in Progress	194.1	171.9
Total Property, Plant and Equipment	7,319.8	7,103.4
Accumulated Depreciation and Amortization	2,107.1	2,048.7
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,212.7	5,054.7
OTHER NONCURRENT ASSETS		
Notes Receivable – Affiliated	32.3	32.3
Regulatory Assets	1,016.4	1,113.0
Securitized Assets	68.0	85.9
Long-term Risk Management Assets	—	19.2
Deferred Charges and Other Noncurrent Assets	116.0	259.6
TOTAL OTHER NONCURRENT ASSETS	1,232.7	1,510.0
TOTAL ASSETS	$6,664.1	$ 7,137.9

See
Condensed
Notes to
Condensed

Financial Statements of Registrants beginning on page 113.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2016 and December 31, 2015
(dollars in millions)
(Unaudited)

	September 30, 2016	December 31, 2015
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 152.9	$ 156.4
Affiliated Companies	90.9	88.7
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2016 and December 31, 2015 Amounts Include $46.3 and $45.9, Respectively, Related to Ohio Phase-in-Recovery Funding)	46.4	395.9
Risk Management Liabilities	5.6	3.6
Customer Deposits	71.2	65.4
Accrued Taxes	246.6	528.3
Accrued Interest	38.4	33.0
Other Current Liabilities	87.0	154.3
TOTAL CURRENT LIABILITIES	739.0	1,425.6
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (September 30, 2016 and December 31, 2015 Amounts Include $93.7 and $139.4, Respectively, Related to Ohio Phase-in-Recovery Funding)	1,717.0	1,761.8
Long-term Risk Management Liabilities	103.5	—
Deferred Income Taxes	1,414.0	1,383.2
Regulatory Liabilities and Deferred Investment Tax Credits	555.7	514.2
Employee Benefits and Pension Obligations	27.7	35.8
Deferred Credits and Other Noncurrent Liabilities	26.9	30.7
TOTAL NONCURRENT LIABILITIES	3,844.8	3,725.7
TOTAL LIABILITIES	4,583.8	5,151.3
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	321.2	321.2
Paid-in Capital	838.8	838.8
Retained Earnings	917.0	822.3
Accumulated Other Comprehensive Income (Loss)	3.3	4.3
TOTAL COMMON SHAREHOLDER'S EQUITY	2,080.3	1,986.6
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 6,664.1	$ 7,137.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2016	2015
OPERATING ACTIVITIES		
Net Income	$ 244.7	$ 184.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	189.0	178.6
Amortization of Generation Deferrals	173.0	122.2
Deferred Income Taxes	28.6	28.1
Carrying Costs Income	(4.0)	(10.0)
Allowance for Equity Funds Used During Construction	(3.7)	(7.0)
Mark-to-Market of Risk Management Contracts	124.7	31.8
Pension Contributions to Qualified Plan Trust	(7.1)	(7.7)
Property Taxes	169.1	148.4
Purchased Electricity Over/Under-Recovery, Net	(21.1)	(15.7)
Deferral of Ohio Capacity Costs, Net	—	(30.7)
Change in Other Noncurrent Assets	(124.9)	27.8
Change in Other Noncurrent Liabilities	17.2	32.3
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	8.8	41.2
Materials and Supplies	0.5	(15.0)
Accounts Payable	2.0	(78.8)
Accrued Taxes, Net	(291.1)	(134.7)
Other Current Assets	(4.5)	(3.2)
Other Current Liabilities	(26.9)	1.7
Net Cash Flows from Operating Activities	474.3	494.0
INVESTING ACTIVITIES		
Construction Expenditures	(276.4)	(346.8)
Change in Restricted Cash for Securitized Funding	11.6	12.5

Change in Advances to Affiliates, Net	330.9	33.3
Proceeds from Notes Receivable – Affiliated	—	86.0
Other Investing Activities	9.0	10.9
Net Cash Flows from (Used for) Investing Activities	75.1	(204.1)
FINANCING ACTIVITIES		
Retirement of Long-term Debt – Nonaffiliated	(395.9)	(131.5)
Principal Payments for Capital Lease Obligations	(3.1)	(2.9)
Dividends Paid on Common Stock	(150.0)	(156.3)
Other Financing Activities	0.5	1.2
Net Cash Flows Used for Financing Activities	(548.5)	(289.5)
Net Increase in Cash and Cash Equivalents	0.9	0.4
Cash and Cash Equivalents at Beginning of Period	3.1	2.9
Cash and Cash Equivalents at End of Period	$ 4.0	$ 3.3
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 78.2	$ 79.0
Net Cash Paid for Income Taxes	178.0	24.1
Noncash Acquisitions Under Capital Leases	2.4	2.1
Construction Expenditures Included in Current Liabilities as of September 30,	30.0	30.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

PUBLIC SERVICE COMPANY OF OKLAHOMA

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions of KWhs)			
Retail:				
Residential	2,184	2,126	4,925	4,966
Commercial	1,529	1,568	4,001	4,028
Industrial	1,494	1,408	4,162	4,039
Miscellaneous	369	365	955	958
Total Retail	5,576	5,467	14,043	13,991
Wholesale	113	28	226	166
Total KWhs	5,689	5,495	14,269	14,157

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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in degree days)			
Actual - Heating (a)	—	—	782	1,176
Normal - Heating (b)	1	1	1,105	1,089
Actual - Cooling (c)	1,535	1,444	2,247	2,103
Normal - Cooling (b)	1,390	1,387	2,055	2,053

(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) Cooling degree days are calculated on a 65 degree temperature base.

Third Quarter of 2016 Compared to Third Quarter of 2015
Reconciliation of Third Quarter of 2015 to Third Quarter of 2016
Net Income
(in millions)

Third Quarter of 2015	$44.7
Changes in Gross Margin:	
Retail Margins (a)	24.6
Off-system Sales	0.3
Transmission Revenues	(3.4)
Other Revenues	0.4
Total Change in Gross Margin	21.9
Changes in Expenses and Other:	
Other Operation and Maintenance	(1.9)
Depreciation and Amortization	(6.3)
Taxes Other Than Income Taxes	0.2
Allowance for Equity Funds Used During Construction	(1.3)
Interest Expense	0.1
Total Change in Expenses and Other	(9.2)
Income Tax Expense	(4.6)
Third Quarter of 2016	$52.8

(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 $25 million primarily due to the following:
  - A $21 million increase primarily related to interim base rate increases implemented in January 2016. This increase in retail margins has corresponding increases in other items below.
  - A $4 million increase in weather-related usage primarily due to a 6% increase in cooling degree days.
- Transmission Revenues decreased $3 million primarily due to an accrual for SPP sponsor-funded transmission upgrades.

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

- Other Operation and Maintenance expenses increased $2 million primarily due to the following:
  - A $5 million increase in transmission expenses primarily due to increased SPP transmission services.
  - A $2 million increase in distribution expenses primarily due an increase in energy efficiency programs.

  These increases were partially offset by:
  - A $4 million decrease in general and administrative expenses.
  - A $2 million decrease in generation plant maintenance expenses.
- Depreciation and Amortization expenses increased $6 million primarily due to the following:
  - A $9 million increase in depreciation primarily related to interim rate increases.

This increase was partially offset by:

- A $3 million decrease in amortization related to advanced metering infrastructure projects.
- Income Tax Expense increased $5 million primarily due to an increase in pretax book income.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015
Reconciliation of Nine Months Ended September 30, 2015 to
Nine Months Ended September 30, 2016
Net Income
(in millions)

Nine Months Ended September 30, 2015	$85.5
Changes in Gross Margin:	
Retail Margins (a)	49.6
Off-system Sales	0.2
Transmission Revenues	(3.4)
Other Revenues	1.4
Total Change in Gross Margin	47.8
Changes in Expenses and Other:	
Other Operation and Maintenance	(9.8)
Depreciation and Amortization	(19.7)
Interest Income	0.2
Allowance for Equity Funds Used During Construction	(1.1)
Interest Expense	(0.2)
Total Change in Expenses and Other	(30.6)
Income Tax Expense	(5.3)
Nine Months Ended September 30, 2016	$97.4

(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 $50 million primarily related to interim base rate increases implemented in January 2016. This increase in retail margins has corresponding increases in other items below.
- Transmission Revenues decreased $3 million primarily due to an accrual for SPP sponsor-funded transmission upgrades.

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

- Other Operation and Maintenance expenses increased $10 million primarily due to the following:
  - A $12 million increase in transmission expenses primarily due to increased SPP transmission services.
  - A $4 million increase in distribution expenses primarily due to amortization of 2013 storm restoration expenses beginning in May 2015 and an increase in energy efficiency programs.

  These increases were partially offset by:
  - A $5 million decrease in generation plant maintenance expenses.
  - A $2 million decrease in general and administrative expenses.
- Depreciation and Amortization expenses increased $20 million primarily due to the following:
  - A $25 million increase in depreciation primarily related to interim rate increases.

  This increase was partially offset by:

- A $6 million decrease in amortization related to advanced metering infrastructure projects.
- Income Tax Expense increased $5 million primarily due to an increase in pretax book income.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
REVENUES				
Electric Generation, Transmission and Distribution	$400.9	$418.6	$971.3	$1,040.9
Sales to AEP Affiliates	0.1	1.1	2.0	3.5
Other Revenues	0.7	0.6	2.9	2.2
TOTAL REVENUES	401.7	420.3	976.2	1,046.6
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	16.4	87.7	43.0	226.3
Purchased Electricity for Resale	130.8	103.2	315.3	253.8
Purchased Electricity from AEP Affiliates	3.2	—	3.6	—
Other Operation	81.0	77.5	211.8	199.3
Maintenance	25.6	27.2	71.6	74.3
Depreciation and Amortization	37.2	30.9	109.9	90.2
Taxes Other Than Income Taxes	9.1	9.3	27.8	27.8
TOTAL EXPENSES	303.3	335.8	783.0	871.7
OPERATING INCOME	98.4	84.5	193.2	174.9
Other Income (Expense):				
Interest Income	0.2	0.2	0.5	0.3
Allowance for Equity Funds Used During Construction	1.1	2.4	4.9	6.0
Interest Expense	(14.9)	(15.0)	(44.6)	(44.4)
INCOME BEFORE INCOME TAX EXPENSE	84.8	72.1	154.0	136.8
Income Tax Expense	32.0	27.4	56.6	51.3
NET INCOME	$52.8	$44.7	$97.4	$85.5

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

See Condensed Notes to Condensed Financial

Statements of
Registrants
beginning on
page 113.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net Income	$52.8	$44.7	$97.4	$85.5
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended September 30, 2016 and 2015, Respectively, and $(0.3) and $(0.3) for the Nine Months Ended September 30, 2016 and 2015, Respectively	(0.2)	(0.1)	(0.6)	(0.5)
TOTAL COMPREHENSIVE INCOME	$52.6	$44.6	$96.8	$85.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$ 157.2	$ 364.0	$ 502.0	$ 5.0	$ 1,028.2
Net Income			85.5		85.5
Other Comprehensive Loss				(0.5)	(0.5)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2015	$ 157.2	$ 364.0	$ 587.5	$ 4.5	$ 1,113.2
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2015	$ 157.2	$ 364.0	$ 594.5	$ 4.2	$ 1,119.9
Net Income			97.4		97.4
Other Comprehensive Loss				(0.6)	(0.6)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2016	$ 157.2	$ 364.0	$ 691.9	$ 3.6	$ 1,216.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2016 and December 31, 2015
(in millions)
(Unaudited)

	September 30, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$2.0	$ 1.4
Advances to Affiliates	51.1	80.6
Accounts Receivable:		
Customers	17.8	26.0
Affiliated Companies	23.5	20.8
Miscellaneous	4.4	3.3
Allowance for Uncollectible Accounts	(0.6)	(0.6)
Total Accounts Receivable	45.1	49.5
Fuel	21.8	17.6
Materials and Supplies	50.1	51.9
Risk Management Assets	1.1	0.6
Accrued Tax Benefits	7.6	37.3
Regulatory Asset for Under-Recovered Fuel Costs	4.1	—
Prepayments and Other Current Assets	10.8	6.5
TOTAL CURRENT ASSETS	193.7	245.4
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,552.1	1,302.6
Transmission	832.1	815.4
Distribution	2,284.4	2,206.7
Other Property, Plant and Equipment (December 31, 2015 Amount Includes 2016 Plant Retirement)	243.0	405.7
Construction Work in Progress	127.9	315.3
Total Property, Plant and Equipment	5,039.5	5,045.7
Accumulated Depreciation and Amortization	1,297.4	1,352.5
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	3,742.1	3,693.2
OTHER NONCURRENT ASSETS		
Regulatory Assets	322.2	214.8
Employee Benefits and Pension Assets	15.7	10.6
Deferred Charges and Other Noncurrent Assets	18.1	6.4
TOTAL OTHER NONCURRENT ASSETS	356.0	231.8
TOTAL ASSETS	$4,291.8	$ 4,170.4

See
Condensed
Notes to
Condensed

Financial Statements of Registrants beginning on page 113.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2016 and December 31, 2015
(Unaudited)

	September 30, 2016	December 31, 2015
	(in millions)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$116.7	$ 108.2
Affiliated Companies	40.3	51.5
Long-term Debt Due Within One Year – Nonaffiliated	125.5	275.4
Risk Management Liabilities	—	0.2
Customer Deposits	50.2	50.3
Accrued Taxes	39.3	23.6
Accrued Interest	14.5	15.1
Regulatory Liability for Over-Recovered Fuel Costs	—	76.1
Other Current Liabilities	55.0	64.4
TOTAL CURRENT LIABILITIES	441.5	664.8
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,160.7	1,010.7
Deferred Income Taxes	1,055.0	971.8
Regulatory Liabilities and Deferred Investment Tax Credits	340.0	335.1
Asset Retirement Obligations	52.5	39.9
Employee Benefits and Pension Obligations	13.8	14.5
Deferred Credits and Other Noncurrent Liabilities	11.6	13.7
TOTAL NONCURRENT LIABILITIES	2,633.6	2,385.7
TOTAL LIABILITIES	3,075.1	3,050.5
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	157.2	157.2
Paid-in Capital	364.0	364.0
Retained Earnings	691.9	594.5
Accumulated Other Comprehensive Income (Loss)	3.6	4.2
TOTAL COMMON SHAREHOLDER'S EQUITY	1,216.7	1,119.9
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$4,291.8	$ 4,170.4

See
Condensed

Notes to Condensed Financial Statements of Registrants beginning on page 113.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Nine Months Ended September 30,					
	2016			2015		
OPERATING ACTIVITIES						
Net Income	$	97.4		$	85.5	
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:						
Depreciation and Amortization	109.9			90.2		
Deferred Income Taxes	79.5			40.1		
Allowance for Equity Funds Used During Construction	(4.9		)	(6.0		)
Mark-to-Market of Risk Management Contracts	(0.7		)	(1.9		)
Pension Contributions to Qualified Plan Trust	(5.6		)	(5.8		)
Property Taxes	(8.0		)	(8.0		)
Deferred Fuel Over/Under-Recovery, Net	(80.2		)	76.9		
Change in Other Noncurrent Assets	(18.8		)	(13.6		)
Change in Other Noncurrent Liabilities	(3.7		)	8.2		
Changes in Certain Components of Working Capital:						
Accounts Receivable, Net	4.4			(2.6		)
Fuel, Materials and Supplies	(2.4		)	(1.1		)
Accounts Payable	23.1			(9.3		)
Accrued Taxes, Net	45.4			21.0		
Other Current Assets	(2.2		)	(1.9		)
Other Current Liabilities	(1.1		)	8.0		
Net Cash Flows from Operating Activities	232.1			279.7		
INVESTING ACTIVITIES						
Construction Expenditures	(266.8		)	(262.9		)
Change in Advances to Affiliates, Net	29.5			(116.3		)
Other Investing Activities	8.7			7.6		
Net Cash Flows Used for Investing Activities	(228.6		)	(371.6		)
FINANCING ACTIVITIES						

Issuance of Long-term Debt – Nonaffiliated	150.0		248.8	
Change in Advances from Affiliates, Net	—		(154.2	)
Retirement of Long-term Debt – Nonaffiliated	(150.3	)	(0.3	)
Principal Payments for Capital Lease Obligations	(3.0	)	(2.8	)
Other Financing Activities	0.4		0.7	
Net Cash Flows from (Used for) Financing Activities	(2.9	)	92.2	
Net Increase in Cash and Cash Equivalents	0.6		0.3	
Cash and Cash Equivalents at Beginning of Period	1.4		1.4	
Cash and Cash Equivalents at End of Period	$ 2.0		$ 1.7	
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$ 45.0		$ 40.6	
Net Cash Paid (Received) for Income Taxes	(50.3	)	12.8	
Noncash Acquisitions Under Capital Leases	2.2		1.5	
Construction Expenditures Included in Current Liabilities as of September 30,	20.2		37.3	

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

100

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions of KWhs)			
Retail:				
Residential	2,105	2,087	4,879	5,135
Commercial	1,793	1,782	4,652	4,705
Industrial	1,254	1,419	3,830	4,079
Miscellaneous	20	19	61	60
Total Retail	5,172	5,307	13,422	13,979
Wholesale	2,326	2,460	6,056	7,092
Total KWhs	7,498	7,767	19,478	21,071

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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in degree days)			
Actual - Heating (a)	—	—	586	920
Normal - Heating (b)	1	1	747	733
Actual - Cooling (c)	1,502	1,500	2,277	2,278
Normal - Cooling (b)	1,410	1,408	2,177	2,175

(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) Cooling degree days are calculated on a 65 degree temperature base.

Third Quarter of 2016 Compared to Third Quarter of 2015
Reconciliation of Third Quarter of 2015 to Third Quarter of 2016
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Third Quarter of 2015	$81.1
Changes in Gross Margin:	
Retail Margins (a)	4.9
Off-system Sales	0.1
Transmission Revenues	11.7
Other Revenues	(0.6)
Total Change in Gross Margin	16.1
Changes in Expenses and Other:	
Other Operation and Maintenance	(7.2)
Depreciation and Amortization	(2.3)
Taxes Other Than Income Taxes	(0.4)
Allowance for Equity Funds Used During Construction	(7.0)
Interest Expense	(3.4)
Total Change in Expenses and Other	(20.3)
Income Tax Expense	4.2
Equity Earnings of Unconsolidated Subsidiary	2.3
Net Income Attributable to Noncontrolling Interest	(0.1)
Third Quarter of 2016	$83.3

(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 $5 million primarily due to the following:
  - A $6 million increase due to revenue increases from rate riders primarily in Texas and Arkansas.
  - A $3 million increase in municipal and cooperative revenues due to formula rate adjustments.

  These increases were partially offset by:
  - A $3 million decrease due to lower weather-normalized margins.
- Transmission Revenues increased $12 million primarily due to an $8 million accrual for SPP sponsor-funded transmission upgrades and an additional $4 million due to increased transmission investments in SPP. This increase was offset by a corresponding increase in Other Operation and Maintenance expenses below.

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

- Other Operation and Maintenance expenses increased $7 million primarily due to the following:
- A $15 million increase in SPP transmission services primarily due to a $12 million accrual for SPP sponsor-funded transmission upgrades. This increase was partially offset by a corresponding increase in Transmission Revenues above.

This increase was partially offset by:

- A $4 million decrease in general and administrative expenses.
- A $2 million decrease in customer related expenses.
- Allowance for Equity Funds Used During Construction decreased $7 million primarily due to the completion of environmental projects.
- Interest Expense increased $3 million due to a decrease in the debt component of AFUDC as a result of decreased environmental projects.
- Income Tax Expense decreased $4 million primarily due to a decrease in pretax book income and the recording of federal income tax adjustments, partially offset by other book/tax differences which are accounted for on a flow-through basis.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015

Reconciliation of Nine Months Ended September 30, 2015 to Nine Months Ended September 30, 2016
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Nine Months Ended September 30, 2015	$ 185.3
Changes in Gross Margin:	
Retail Margins (a)	(40.7)
Off-system Sales	(1.0)
Transmission Revenues	19.3
Other Revenues	(1.1)
Total Change in Gross Margin	(23.5)
Changes in Expenses and Other:	
Other Operation and Maintenance	(30.4)
Depreciation and Amortization	(4.3)
Taxes Other Than Income Taxes	(0.7)
Interest Income	(1.2)
Allowance For Equity Funds Used During Construction	(8.7)
Interest Expense	(0.6)
Total Change in Expenses and Other	(45.9)
Income Tax Expense	31.5
Equity Earnings of Unconsolidated Subsidiary	2.8
Net Income Attributable to Noncontrolling Interest	(0.3)
Nine Months Ended September 30, 2016	$ 149.9

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

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, and purchased electricity were as follows:

- Retail Margins decreased $41 million primarily due to the following:
- A $23 million decrease due to fuel cost recovery adjustments in 2015.
- A $22 million decrease in municipal and cooperative revenues due to a true-up of formula rates in 2015.
- An $18 million decrease in weather-related usage due to a 36% decrease in heating degree days.

These decreases were partially offset by:

- A $16 million increase due to revenue increases from rate riders primarily in Arkansas and Texas.
- A $6 million increase due to higher weather-normalized margins.
- Transmission Revenues increased $19 million primarily due to an additional $9 million in increased transmission investments in SPP and an $8 million accrual for SPP sponsor-funded transmission upgrades. This increase was offset by a corresponding increase in Other Operation and Maintenance expenses below.

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

- Other Operation and Maintenance expenses increased $30 million primarily due to the following:
  - A $21 million increase in SPP transmission services primarily due to a $12 million accrual for SPP sponsor-funded transmission upgrades and an additional $7 million in increased transmission investments in SPP. This increase was partially offset by a corresponding increase in Transmission Revenues above.
  - A $7 million increase in generation plant expenses primarily due to planned maintenance.
  - A $6 million increase in general and administrative expenses.
- Depreciation and Amortization expenses increased $4 million primarily due to a higher depreciable base.
- Allowance for Equity Funds Used During Construction decreased $9 million primarily due to the completion of environmental projects.
- Income Tax Expense decreased $32 million primarily due to a decrease in pretax book income and the recording of state income tax adjustments, partially offset by other book/tax differences which are accounted for on a flow-through basis.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2016	2015	2016	2015
REVENUES				
Electric Generation, Transmission and Distribution	$530.5	$526.0	$1,324.1	$1,387.7
Sales to AEP Affiliates	8.6	5.9	20.0	13.1
Other Revenues	0.6	0.6	1.6	1.5
TOTAL REVENUES	539.7	532.5	1,345.7	1,402.3
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	158.8	180.0	403.3	463.1
Purchased Electricity for Resale	35.9	23.6	97.5	70.8
Other Operation	89.2	81.4	243.3	214.8
Maintenance	33.8	34.4	102.0	100.1
Depreciation and Amortization	51.2	48.9	148.1	143.8
Taxes Other Than Income Taxes	23.4	23.0	66.8	66.1
TOTAL EXPENSES	392.3	391.3	1,061.0	1,058.7
OPERATING INCOME	147.4	141.2	284.7	343.6
Other Income (Expense):				
Interest Income	—	—	—	1.2
Allowance for Equity Funds Used During Construction	0.1	7.1	9.5	18.2
Interest Expense	(32.6)	(29.2)	(92.0)	(91.4)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	114.9	119.1	202.2	271.6
Income Tax Expense	33.2	37.4	53.9	85.4
Equity Earnings of Unconsolidated Subsidiary	2.7	0.4	4.9	2.1
NET INCOME	84.4	82.1	153.2	188.3
Net Income Attributable to Noncontrolling Interest	1.1	1.0	3.3	3.0
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$83.3	$81.1	$149.9	$185.3

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

See
Condensed
Notes to
Condensed
Financial
Statements of
Registrants
beginning on
page 113.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net Income	$84.4	$82.1	$153.2	$188.3
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.2 and $0.2 for the Three Months Ended September 30, 2016 and 2015, Respectively, and $0.7 and $0.8 for the Nine Months Ended September 30, 2016 and 2015, Respectively	0.4	0.4	1.3	1.5
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended September 30, 2016 and 2015, Respectively, and $(0.3) and $(0.4) for the Nine Months Ended September 30, 2016 and 2015, Respectively	(0.1)	(0.2)	(0.5)	(0.7)
TOTAL OTHER COMPREHENSIVE INCOME	0.3	0.2	0.8	0.8
TOTAL COMPREHENSIVE INCOME	84.7	82.3	154.0	189.1
Total Comprehensive Income Attributable to Noncontrolling Interest	1.1	1.0	3.3	3.0
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$83.6	$81.3	$150.7	$186.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY - DECEMBER 31, 2014	$135.7	$674.6	$1,294.0	$ (7.5)	$ 0.4	$2,097.2
Common Stock Dividends			(90.0)			(90.0)
Common Stock Dividends – Nonaffiliated					(3.1)	(3.1)
Net Income			185.3		3.0	188.3
Other Comprehensive Income				0.8		0.8
Contribution of Mutual Energy SWEPCo, LLC from Parent		2.0				2.0
TOTAL EQUITY - SEPTEMBER 30, 2015	$135.7	$676.6	$1,389.3	$ (6.7)	$ 0.3	$2,195.2
TOTAL EQUITY - DECEMBER 31, 2015	$135.7	$676.6	$1,366.3	$ (9.4)	$ 0.5	$2,169.7
Common Stock Dividends			(90.0)			(90.0)
Common Stock Dividends – Nonaffiliated					(3.5)	(3.5)
Net Income			149.9		3.3	153.2
Other Comprehensive Income				0.8		0.8
TOTAL EQUITY - SEPTEMBER 30, 2016	$135.7	$676.6	$1,426.2	$ (8.6)	$ 0.3	$2,230.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2016 and December 31, 2015
(in millions)
(Unaudited)

	September 30, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents (September 30, 2016 and December 31, 2015 Amounts Include $12.8 and $3.7, Respectively, Related to Sabine)	$ 15.2	$ 5.2
Advances to Affiliates	299.4	2.0
Accounts Receivable:		
Customers	25.0	40.2
Affiliated Companies	30.4	22.0
Miscellaneous	22.4	27.1
Allowance for Uncollectible Accounts	(1.6)	(0.9)
Total Accounts Receivable	76.2	88.4
Fuel (September 30, 2016 and December 31, 2015 Amounts Include $33.4 and $40.4, Respectively, Related to Sabine)	109.4	142.1
Materials and Supplies	70.8	71.5
Risk Management Assets	1.4	0.8
Regulatory Asset for Under-Recovered Fuel Costs	0.8	4.1
Prepayments and Other Current Assets	21.0	21.2
TOTAL CURRENT ASSETS	594.2	335.3
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,581.9	3,943.5
Transmission	1,487.6	1,387.8
Distribution	1,994.5	1,957.3
Other Property, Plant and Equipment (December 31, 2015 Amount Includes 2016 Plant Retirement) (September 30, 2016 and December 31, 2015 Amounts Include $282.4 and $297.7, Respectively, Related to Sabine)	707.1	883.5
Construction Work in Progress	188.5	751.3
Total Property, Plant and Equipment	8,959.6	8,923.4
Accumulated Depreciation and Amortization (September 30, 2016 and December 31, 2015 Amounts Include $160.2 and $157.3, Respectively, Related to Sabine)	2,572.4	2,602.3
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,387.2	6,321.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	500.7	415.8
Deferred Charges and Other Noncurrent Assets	116.2	75.8
TOTAL OTHER NONCURRENT ASSETS	616.9	491.6

TOTAL ASSETS	$7,598.3	$ 7,148.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2016 and December 31, 2015
(Unaudited)

	September 30, 2016	December 31, 2015
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$—	$ 58.3
Accounts Payable:		
General	129.3	150.4
Affiliated Companies	51.6	78.8
Long-term Debt Due Within One Year – Nonaffiliated	354.0	3.3
Risk Management Liabilities	—	3.1
Customer Deposits	61.8	61.4
Accrued Taxes	74.0	58.3
Accrued Interest	23.0	43.0
Obligations Under Capital Leases	16.8	21.9
Other Current Liabilities	81.0	110.7
TOTAL CURRENT LIABILITIES	791.5	589.2
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,320.0	2,270.2
Long-term Risk Management Liabilities	—	2.1
Deferred Income Taxes	1,562.1	1,399.8
Regulatory Liabilities and Deferred Investment Tax Credits	446.9	448.8
Asset Retirement Obligations	127.4	117.5
Employee Benefits and Pension Obligations	26.6	25.8
Obligations Under Capital Leases	68.5	75.6
Deferred Credits and Other Noncurrent Liabilities	25.1	49.3
TOTAL NONCURRENT LIABILITIES	4,576.6	4,389.1
TOTAL LIABILITIES	5,368.1	4,978.3
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	135.7	135.7
Paid-in Capital	676.6	676.6
Retained Earnings	1,426.2	1,366.3
Accumulated Other Comprehensive Income (Loss)	(8.6)	(9.4)
TOTAL COMMON SHAREHOLDER’S EQUITY	2,229.9	2,169.2
Noncontrolling Interest	0.3	0.5

TOTAL EQUITY	2,230.2	2,169.7
TOTAL LIABILITIES AND EQUITY	$7,598.3	$ 7,148.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2016 and 2015
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2016	2015
OPERATING ACTIVITIES		
Net Income	$153.2	$188.3
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	148.1	143.8
Deferred Income Taxes	141.9	45.7
Allowance for Equity Funds Used During Construction	(9.5)	(18.2)
Mark-to-Market of Risk Management Contracts	(5.8)	(0.3)
Pension Contributions to Qualified Plan Trust	(8.3)	(8.1)
Property Taxes	(13.7)	(13.0)
Deferred Fuel Over/Under-Recovery, Net	1.2	11.7
Change in Other Noncurrent Assets	18.4	2.0
Change in Other Noncurrent Liabilities	(25.8)	(1.1)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	12.2	2.8
Fuel, Materials and Supplies	33.4	24.8
Accounts Payable	(17.2)	(17.1)
Accrued Taxes, Net	14.1	53.1
Accrued Interest	(20.0)	(21.2)
Other Current Assets	(2.4)	2.8
Other Current Liabilities	(24.8)	(23.7)
Net Cash Flows from Operating Activities	395.0	372.3
INVESTING ACTIVITIES		
Construction Expenditures	(315.3)	(408.3)
Change in Advances to Affiliates, Net	(297.4)	(2.0)
Other Investing Activities	(1.9)	4.4
Net Cash Flows Used for Investing Activities	(614.6)	(405.9)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	402.2	446.0
Change in Advances from Affiliates, Net	(58.3)	—
Retirement of Long-term Debt – Nonaffiliated	(3.3)	(306.8)
Principal Payments for Capital Lease Obligations	(18.6)	(13.4)
Dividends Paid on Common Stock	(90.0)	(90.0)
Dividends Paid on Common Stock – Nonaffiliated	(3.5)	(3.1)
Other Financing Activities	1.1	0.8
Net Cash Flows from Financing Activities	229.6	33.5
Net Increase (Decrease) in Cash and Cash Equivalents	10.0	(0.1)
Cash and Cash Equivalents at Beginning of Period	5.2	14.4

Cash and Cash Equivalents at End of Period	$15.2	$14.3
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$107.6	$106.1
Net Cash Paid (Received) for Income Taxes	(66.6)	12.3
Noncash Acquisitions Under Capital Leases	5.5	1.5
Construction Expenditures Included in Current Liabilities as of September 30,	54.3	85.3
Noncash Contribution of Mutual Energy SWEPCo, LLC from Parent	—	(2.0)
Noncash Increase in Advances to Affiliates, Net due to Contribution of Mutual Energy SWEPCo, LLC	—	2.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 113.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANTS

The condensed notes to condensed financial statements are a combined presentation for the Registrants. The following list indicates Registrants to which the notes apply. Specific disclosures within each note apply to all Registrants unless indicated otherwise:

1. SIGNIFICANT ACCOUNTING MATTERS

The disclosures in this note apply to all Registrants unless indicated otherwise.

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. Net income for the three and nine months ended September 30, 2016 is not necessarily indicative of results that may be expected for the year ending December 31, 2016. The condensed financial statements are unaudited and should be read in conjunction with the audited 2015 financial statements and notes thereto, which are included in the Registrant's Annual Reports on Form 10-K as filed with the SEC on February 23, 2016.

Investment Tax Credits

Investment tax credits (ITC) were historically accounted for under the flow-through method, except where regulatory commissions reflected ITC in the rate-making process. In the third quarter of 2016, AEP and subsidiaries changed accounting for the recognition of ITC and elected to apply the preferred deferral methodology. Retrospective application is not necessary for reporting periods prior to 2016 as the financial impact to AEP and subsidiaries was immaterial.

Deferred ITC is amortized to income tax expense over the life of the asset. Amortization of deferred ITC begins when the asset is placed into service, except where regulatory commissions reflect ITC in the rate-making process, then amortization begins when the cash tax benefit is recognized.

Earnings Per Share (EPS) (Applies to AEP)

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 AEP's basic and diluted EPS calculations included on the statements of operations:

	Three Months Ended September 30,			
	2016		2015	
	(in millions, except per share data)			
		$/share		$/share
Income (Loss) from Continuing Operations	$(764.2)		$511.8	
Less: Net Income Attributable to Noncontrolling Interests	1.6		1.3	
Earnings (Loss) Attributable to AEP Common Shareholders from Continuing Operations	$(765.8)		$510.5	

Weighted Average Number of Basic Shares Outstanding	491.7	$(1.56)	490.6	$ 1.04
Weighted Average Dilutive Effect of Restricted Stock Units	0.1	—	0.2	—
Weighted Average Number of Diluted Shares Outstanding	491.8	$(1.56)	490.8	$ 1.04

	Nine Months Ended September 30,			
	2016		2015	
	(in millions, except per share data)			
		$/share		$/share
Income from Continuing Operations	$245.3		$1,563.4	
Less: Net Income Attributable to Noncontrolling Interests	5.3		4.1	
Earnings Attributable to AEP Common Shareholders from Continuing Operations	$240.0		$1,559.3	
Weighted Average Number of Basic Shares Outstanding	491.4	$ 0.49	490.2	$ 3.18
Weighted Average Dilutive Effect of Restricted Stock Units	0.2	—	0.2	—
Weighted Average Number of Diluted Shares Outstanding	491.6	$ 0.49	490.4	$ 3.18

There were no antidilutive shares outstanding as of September 30, 2016 and 2015.

2. NEW ACCOUNTING PRONOUNCEMENTS

The disclosures in this note apply to all Registrants unless indicated otherwise.

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

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, determine 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 FASB deferred implementation of ASU 2014-09 under the terms in ASU 2015-14, "Revenue from Contracts with Customers (Topic: 606): Deferral of the Effective Date." The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted for annual periods beginning after December 15, 2016. As applicable, this standard may change the amount of revenue recognized on the statements of income in each reporting period. Management is analyzing the impact of this new standard and the related ASUs that clarify guidance in the standard. At this time, management cannot estimate the impact of adoption on revenue or net income. Management plans to adopt ASU 2014-09 effective January 1, 2018.

ASU 2015-11 "Simplifying the Measurement of Inventory" (ASU 2015-11)

In July 2015, the FASB issued ASU 2015-11 simplifying 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 does not expect the new standard to impact the Registrants' results of operations, financial position or cash flows. Management plans to adopt ASU 2015-11 prospectively, effective January 1, 2017.

ASU 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities" (ASU 2016-01)

In January 2016, the FASB issued ASU 2016-01 enhancing the reporting model for financial instruments. Under the new standard, equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) are required to be measured at fair value with changes in fair value recognized in net income. The new standard also amends disclosure requirements and requires separate presentation of financial assets and liabilities by measurement category and form of financial asset (that is, securities or loans and receivables) on the balance sheet or the accompanying notes to the financial statements. The amendments also clarify that an entity should evaluate the need for a valuation allowance on a deferred tax asset related to available-for-sale securities in combination with the entity's other deferred tax assets.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted. The amendments will be applied by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. 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 2016-01 effective January 1, 2018.

116

ASU 2016-02 “Accounting for Leases” (ASU 2016-02)

In February 2016, the FASB issued ASU 2016-02 increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheets. Additionally, a capital lease will be known as a finance lease going forward. Leases with lease terms of 12 months or longer will be subject to the new requirements. Fundamentally, the criteria used to determine lease classification will remain the same, but will be more subjective under the new standard.

The new accounting guidance is effective for annual periods beginning after December 15, 2018 with early adoption permitted. The guidance will be applied by means of a modified retrospective approach. The modified retrospective approach will require lessees and lessors to recognize and measure leases at the beginning of the earliest period presented as well as a number of optional practical expedients that entities may elect to apply. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption. Management expects the new standard to impact the Registrants’ financial position, but not the Registrants’ results of operations or cash flows. Management plans to adopt ASU 2016-02 effective January 1, 2019.

ASU 2016-09 “Compensation – Stock Compensation” (ASU 2016-09)

In March 2016, the FASB issued ASU 2016-09 simplifying the accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities and classification on the statements of cash flows. Under the new standard, all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) should be recognized as income tax expense or benefit on the statements of income. Under current GAAP, excess tax benefits are recognized in additional paid-in capital while tax deficiencies are recognized either as an offset to accumulated excess tax benefits, if any, or on the statements of income.

The new accounting guidance is effective for annual periods beginning after December 15, 2016. Early adoption is permitted in any interim or annual period. Certain provisions require retrospective/modified retrospective transition while others are to be applied prospectively. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption. Management plans to adopt ASU 2016-09 effective January 1, 2017.

ASU 2016-13 “Measurement of Credit Losses on Financial Instruments” (ASU 2016-13)

In June 2016, the FASB issued ASU 2016-13 requiring an allowance to be recorded for all expected credit losses for financial assets. The allowance for credit losses is based on historical information, current conditions and reasonable and supportable forecasts. The new standard also makes revisions to the other than temporary impairment model for available-for-sale debt securities. Disclosures of credit quality indicators in relation to the amortized cost of financing receivables are further disaggregated by year of origination.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2019 with early adoption permitted for interim and annual periods beginning after December 15, 2018. The amendments will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. 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 2016-13 effective January 1, 2020.

3. COMPREHENSIVE INCOME

The disclosures in this note apply to all Registrants unless indicated otherwise.

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the three and nine months ended September 30, 2016 and 2015. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 7 for additional details.

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2016

	Cash Flow Hedges				
	Commodity	Interest Rate and Foreign Currency	Securities Available for Sale	Pension and OPEB	Total
	(in millions)				
Balance in AOCI as of June 30, 2016	$1.9	$(16.5)	$ 8.3	$(111.6)	$(117.9)
Change in Fair Value Recognized in AOCI	(26.7)	—	0.5	—	(26.2)
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues	(5.4)	—	—	—	(5.4)
Purchased Electricity for Resale	1.8	—	—	—	1.8
Interest Expense	—	0.6	—	—	0.6
Amortization of Prior Service Cost (Credit)	—	—	—	(4.8)	(4.8)
Amortization of Actuarial (Gains)/Losses	—	—	—	5.0	5.0
Reclassifications from AOCI, before Income Tax (Expense) Credit	(3.6)	0.6	—	0.2	(2.8)
Income Tax (Expense) Credit	(1.3)	0.2	—	—	(1.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(2.3)	0.4	—	0.2	(1.7)
Net Current Period Other Comprehensive Income (Loss)	(29.0)	0.4	0.5	0.2	(27.9)
Balance in AOCI as of September 30, 2016	$(27.1)	$(16.1)	$ 8.8	$(111.4)	$(145.8)

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 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 June 30, 2015	$(5.2)	$(17.7)	$ 8.0	$(87.6)	$(102.5)
Change in Fair Value Recognized in AOCI	(3.3)	0.3	(1.3)	—	(4.3)
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues	(19.5)	—	—	—	(19.5)

Purchased Electricity for Resale	14.3	—	—	—	14.3
Interest Expense	—	(0.2)	—	—	(0.2)
Amortization of Prior Service Cost (Credit)	—	—	—	(4.8)	(4.8)
Amortization of Actuarial (Gains)/Losses	—	—	—	5.3	5.3
Reclassifications from AOCI, before Income Tax (Expense) Credit	(5.2)	(0.2)	—	0.5	(4.9)
Income Tax (Expense) Credit	(3.0)	(0.1)	—	0.2	(2.9)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(2.2)	(0.1)	—	0.3	(2.0)
Net Current Period Other Comprehensive Income (Loss)	(5.5)	0.2	(1.3)	0.3	(6.3)
Balance in AOCI as of September 30, 2015	$(10.7)	$(17.5)	$ 6.7	$(87.3)	$(108.8)

118

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2016

	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, 2015	$(5.2)	$(17.2)	$ 7.1	$(111.8)	$(127.1)
Change in Fair Value Recognized in AOCI	(17.7)	—	1.7	—	(16.0)
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues	(20.7)	—	—	—	(20.7)
Purchased Electricity for Resale	14.2	—	—	—	14.2
Interest Expense	—	1.7	—	—	1.7
Amortization of Prior Service Cost (Credit)	—	—	—	(14.6)	(14.6)
Amortization of Actuarial (Gains)/Losses	—	—	—	15.2	15.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	(6.5)	1.7	—	0.6	(4.2)
Income Tax (Expense) Credit	(2.3)	0.6	—	0.2	(1.5)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(4.2)	1.1	—	0.4	(2.7)
Net Current Period Other Comprehensive Income (Loss)	(21.9)	1.1	1.7	0.4	(18.7)
Balance in AOCI as of September 30, 2016	$(27.1)	$(16.1)	$ 8.8	$(111.4)	$(145.8)

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 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	$1.6	$(19.1)	$ 7.7	$(93.3)	$(103.1)
Change in Fair Value Recognized in AOCI	(2.0)	0.9	(1.0)	—	(2.1)
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues	(36.3)	—	—	—	(36.3)
Purchased Electricity for Resale	20.4	—	—	—	20.4
Interest Expense	—	1.0	—	—	1.0
Amortization of Prior Service Cost (Credit)	—	—	—	(14.6)	(14.6)
Amortization of Actuarial (Gains)/Losses	—	—	—	16.0	16.0
Reclassifications from AOCI, before Income Tax (Expense) Credit	(15.9)	1.0	—	1.4	(13.5)
Income Tax (Expense) Credit	(5.6)	0.3	—	0.5	(4.8)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(10.3)	0.7	—	0.9	(8.7)
Net Current Period Other Comprehensive Income (Loss)	(12.3)	1.6	(1.0)	0.9	(10.8)
Pension and OPEB Adjustment Related to Mitchell Plant	—	—	—	5.1	5.1
Balance in AOCI as of September 30, 2015	$(10.7)	$(17.5)	$ 6.7	$(87.3)	$(108.8)

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2016

	Cash Flow Hedges Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2016	$3.2	$ (7.1)	$(3.9)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	(0.2)	—	(0.2)
Amortization of Prior Service Cost (Credit)	—	(1.2)	(1.2)
Amortization of Actuarial (Gains)/Losses	—	0.7	0.7
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.2)	(0.5)	(0.7)
Income Tax (Expense) Credit	—	(0.2)	(0.2)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.2)	(0.3)	(0.5)
Net Current Period Other Comprehensive Loss	(0.2)	(0.3)	(0.5)
Balance in AOCI as of September 30, 2016	$3.0	$ (7.4)	$(4.4)

APCo

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

	Cash Flow Hedges Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2015	$4.0	$ 0.2	$4.2
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	(0.3)	—	(0.3)
Amortization of Prior Service Cost (Credit)	—	(1.2)	(1.2)
Amortization of Actuarial (Gains)/Losses	—	0.5	0.5
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.3)	(0.7)	(1.0)
Income Tax (Expense) Credit	(0.1)	(0.2)	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.2)	(0.5)	(0.7)
Net Current Period Other Comprehensive Loss	(0.2)	(0.5)	(0.7)
Balance in AOCI as of September 30, 2015	$3.8	$ (0.3)	$3.5

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2016

	Cash Flow Hedges Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2015	$3.6	$ (6.4)	$(2.8)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	(0.8)	—	(0.8)
Amortization of Prior Service Cost (Credit)	—	(3.8)	(3.8)
Amortization of Actuarial (Gains)/Losses	—	2.2	2.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.8)	(1.6)	(2.4)
Income Tax (Expense) Credit	(0.2)	(0.6)	(0.8)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.6)	(1.0)	(1.6)
Net Current Period Other Comprehensive Loss	(0.6)	(1.0)	(1.6)
Balance in AOCI as of September 30, 2016	$3.0	$ (7.4)	$(4.4)

APCo

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

	Cash Flow Hedges Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2014	$3.9	$ 1.1	$5.0
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	(0.1)	—	(0.1)
Amortization of Prior Service Cost (Credit)	—	(3.8)	(3.8)
Amortization of Actuarial (Gains)/Losses	—	1.7	1.7
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.1)	(2.1)	(2.2)
Income Tax (Expense) Credit	—	(0.7)	(0.7)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.1)	(1.4)	(1.5)
Net Current Period Other Comprehensive Loss	(0.1)	(1.4)	(1.5)
Balance in AOCI as of September 30, 2015	$3.8	$ (0.3)	$3.5

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2016

	Cash Flow Hedges Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2016	$(12.6)	$ (3.4)	$(16.0)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	0.5	—	0.5
Amortization of Prior Service Cost (Credit)	—	(0.2)	(0.2)
Amortization of Actuarial (Gains)/Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.5	—	0.5
Income Tax (Expense) Credit	0.2	—	0.2
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.3	—	0.3
Net Current Period Other Comprehensive Income	0.3	—	0.3
Balance in AOCI as of September 30, 2016	$(12.3)	$ (3.4)	$(15.7)

I&M

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

	Cash Flow Hedges Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2015	$(13.9)	$ 0.1	$(13.8)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	0.4	—	0.4
Amortization of Prior Service Cost (Credit)	—	(0.2)	(0.2)
Amortization of Actuarial (Gains)/Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.4	—	0.4
Income Tax (Expense) Credit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.3	—	0.3
Net Current Period Other Comprehensive Income	0.3	—	0.3
Balance in AOCI as of September 30, 2015	$(13.6)	$ 0.1	$(13.5)

122

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2016

	Cash Flow Hedges Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2015	$(13.3)	$ (3.4)	$(16.7)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	1.5	—	1.5
Amortization of Prior Service Cost (Credit)	—	(0.6)	(0.6)
Amortization of Actuarial (Gains)/Losses	—	0.6	0.6
Reclassifications from AOCI, before Income Tax (Expense) Credit	1.5	—	1.5
Income Tax (Expense) Credit	0.5	—	0.5
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1.0	—	1.0
Net Current Period Other Comprehensive Income	1.0	—	1.0
Balance in AOCI as of September 30, 2016	$(12.3)	$ (3.4)	$(15.7)

I&M

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

	Cash Flow Hedges Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2014	$(14.4)	$ 0.1	$(14.3)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	1.2	—	1.2
Amortization of Prior Service Cost (Credit)	—	(0.6)	(0.6)
Amortization of Actuarial (Gains)/Losses	—	0.6	0.6
Reclassifications from AOCI, before Income Tax (Expense) Credit	1.2	—	1.2
Income Tax (Expense) Credit	0.4	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.8	—	0.8
Net Current Period Other Comprehensive Income	0.8	—	0.8
Balance in AOCI as of September 30, 2015	$(13.6)	$ 0.1	$(13.5)

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2016

	Cash Flow Hedges Interest Rate and Foreign Currency (in millions)
Balance in AOCI as of June 30, 2016	$ 3.5
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(0.3)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.3)
Income Tax (Expense) Credit	(0.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.2)
Net Current Period Other Comprehensive Loss	(0.2)
Balance in AOCI as of September 30, 2016	$ 3.3

OPCo

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

	Cash Flow Hedges Interest Rate and Foreign Currency (in millions)
Balance in AOCI as of June 30, 2015	$ 4.9
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(0.5)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.5)
Income Tax (Expense) Credit	(0.2)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.3)
Net Current Period Other Comprehensive Loss	(0.3)
Balance in AOCI as of September 30, 2015	$ 4.6

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2016

	Cash Flow Hedges Interest Rate and Foreign Currency (in millions)
Balance in AOCI as of December 31, 2015	$ 4.3
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(1.4)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1.4)
Income Tax (Expense) Credit	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(1.0)
Net Current Period Other Comprehensive Loss	(1.0)
Balance in AOCI as of September 30, 2016	$ 3.3

OPCo

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

	Cash Flow Hedges Interest Rate and Foreign Currency (in millions)
Balance in AOCI as of December 31, 2014	$ 5.6
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(1.6)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1.6)
Income Tax (Expense) Credit	(0.6)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(1.0)
Net Current Period Other Comprehensive Loss	(1.0)
Balance in AOCI as of September 30, 2015	$ 4.6

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2016

	Cash Flow Hedges Interest Rate and Foreign Currency (in millions)
Balance in AOCI as of June 30, 2016	$ 3.8
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(0.3)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.3)
Income Tax (Expense) Credit	(0.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.2)
Net Current Period Other Comprehensive Loss	(0.2)
Balance in AOCI as of September 30, 2016	$ 3.6

PSO

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

	Cash Flow Hedges Interest Rate and Foreign Currency (in millions)
Balance in AOCI as of June 30, 2015	$ 4.6
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(0.2)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.2)
Income Tax (Expense) Credit	(0.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.1)
Net Current Period Other Comprehensive Loss	(0.1)
Balance in AOCI as of September 30, 2015	$ 4.5

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2016

	Cash Flow Hedges Interest Rate and Foreign Currency (in millions)
Balance in AOCI as of December 31, 2015	$ 4.2
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(0.9)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.9)
Income Tax (Expense) Credit	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.6)
Net Current Period Other Comprehensive Loss	(0.6)
Balance in AOCI as of September 30, 2016	$ 3.6

PSO

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

	Cash Flow Hedges Interest Rate and Foreign Currency (in millions)
Balance in AOCI as of December 31, 2014	$ 5.0
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(0.8)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.8)
Income Tax (Expense) Credit	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.5)
Net Current Period Other Comprehensive Loss	(0.5)
Balance in AOCI as of September 30, 2015	$ 4.5

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2016

	Cash Flow Hedges Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2016	$(8.2)	$ (0.7)	$(8.9)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	0.7	—	0.7
Amortization of Prior Service Cost (Credit)	—	(0.4)	(0.4)
Amortization of Actuarial (Gains)/Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.7	(0.2)	0.5
Income Tax (Expense) Credit	0.3	(0.1)	0.2
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.4	(0.1)	0.3
Net Current Period Other Comprehensive Income (Loss)	0.4	(0.1)	0.3
Balance in AOCI as of September 30, 2016	$(7.8)	$ (0.8)	$(8.6)

SWEPCo

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

	Cash Flow Hedges Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2015	$(10.0)	$ 3.1	$(6.9)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	0.7	—	0.7
Amortization of Prior Service Cost (Credit)	—	(0.5)	(0.5)
Amortization of Actuarial (Gains)/Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.7	(0.4)	0.3
Income Tax (Expense) Credit	0.3	(0.2)	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.4	(0.2)	0.2
Net Current Period Other Comprehensive Income (Loss)	0.4	(0.2)	0.2
Balance in AOCI as of September 30, 2015	$(9.6)	$ 2.9	$(6.7)

128

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2016

	Cash Flow Hedges Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2015	$(9.1)	$(0.3)	$(9.4)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	2.0	—	2.0
Amortization of Prior Service Cost (Credit)	—	(1.4)	(1.4)
Amortization of Actuarial (Gains)/Losses	—	0.6	0.6
Reclassifications from AOCI, before Income Tax (Expense) Credit	2.0	(0.8)	1.2
Income Tax (Expense) Credit	0.7	(0.3)	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1.3	(0.5)	0.8
Net Current Period Other Comprehensive Income (Loss)	1.3	(0.5)	0.8
Balance in AOCI as of September 30, 2016	$(7.8)	$(0.8)	$(8.6)

SWEPCo

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

	Cash Flow Hedges Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2014	$(11.1)	$ 3.6	$(7.5)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	2.4	—	2.4
Amortization of Prior Service Cost (Credit)	—	(1.4)	(1.4)
Amortization of Actuarial (Gains)/Losses	—	0.3	0.3
Reclassifications from AOCI, before Income Tax (Expense) Credit	2.4	(1.1)	1.3
Income Tax (Expense) Credit	0.9	(0.4)	0.5
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1.5	(0.7)	0.8
Net Current Period Other Comprehensive Income (Loss)	1.5	(0.7)	0.8
Balance in AOCI as of September 30, 2015	$(9.6)	$ 2.9	$(6.7)

4. RATE MATTERS

The disclosures in this note apply to all Registrants unless indicated otherwise.

As discussed in the 2015 Annual Report, the Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2015 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 2016 and updates the 2015 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

	AEP	
	September 30, 2016	December 31, 2015
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs - Unrecovered Plant	$161.3	$ —
Storm-Related Costs	25.4	24.2
Plant Retirement Costs - Materials and Supplies	20.8	20.9
Other Regulatory Assets Pending Final Regulatory Approval	1.2	—
Regulatory Assets Currently Not Earning a Return		
Plant Retirement Costs - Asset Retirement Obligation Costs	56.7	59.8
Storm-Related Costs	26.7	18.2
Cook Plant Turbine	12.0	9.7
Peak Demand Reduction/Energy Efficiency	0.2	13.1
Other Regulatory Assets Pending Final Regulatory Approval	39.0	22.0
Total Regulatory Assets Pending Final Regulatory Approval	$343.3	$ 167.9

	APCo	
	September 30, 2016	December 31, 2015
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs - Materials and Supplies	$9.2	$ 9.3
Regulatory Assets Currently Not Earning a Return		
Plant Retirement Costs - Asset Retirement Obligation Costs	29.6	32.7
Peak Demand Reduction/Energy Efficiency - Virginia	—	12.7
Amos Plant Transfer Costs - West Virginia	—	2.0
Other Regulatory Assets Pending Final Regulatory Approval	0.6	0.6
Total Regulatory Assets Pending Final Regulatory Approval	$39.4	$ 57.3

	I&M	
	September 30, 2016	December 31, 2015
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs - Materials and Supplies	$11.6	$ 11.6
Regulatory Assets Currently Not Earning a Return		
Plant Retirement Costs - Asset Retirement Obligation Costs - Indiana	27.1	27.1
Cook Plant Turbine	12.0	9.7
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	7.1	4.2
Rockport Dry Sorbent Injection System - Indiana	5.5	2.8
Stranded Costs on Retired Plant	3.9	3.9
Other Regulatory Assets Pending Final Regulatory Approval	0.6	—
Total Regulatory Assets Pending Final Regulatory Approval	$67.8	$ 59.3

	OPCo	
	September 30, 2016	December 31, 2015
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Not Earning a Return		
OVEC Purchased Power	9.1	—
gridSMART® Costs	3.2	1.3
Total Regulatory Assets Pending Final Regulatory Approval	$12.3	$ 1.3

	PSO	
	September 30, 2016	December 31, 2015
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs - Unrecovered Plant	$85.9	$ —
Plant Retirement Costs - Asset Retirement Obligation Costs	0.5	—
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	20.5	12.3
Other Regulatory Assets Pending Final Regulatory Approval	1.3	1.1
Total Regulatory Assets Pending Final Regulatory Approval	$108.2	$ 13.4

	SWEPCo	
	September 30, 2016	December 31, 2015
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs - Unrecovered Plant	$75.4	$ —
Plant Retirement Costs - Asset Retirement Obligation Costs	0.5	—
Other Regulatory Assets Pending Final Regulatory Approval	0.1	—

Regulatory Assets Currently Not Earning a Return		
Shipe Road Transmission Project - FERC	3.1	3.1
Asset Retirement Obligation - Arkansas, Louisiana	2.5	1.7
Other Regulatory Assets Pending Final Regulatory Approval	2.2	1.1
Total Regulatory Assets Pending Final Regulatory Approval	$83.8	$ 5.9

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

APCo and WPCo Rate Matters (Applies to AEP and APCo)

2016 West Virginia Expanded Net Energy Cost Filing

In June 2016, the WVPSC approved a settlement agreement related to APCo and WPCo's combined annual ENEC filing. The settlement agreement included $38 million ($30 million related to APCo) of additional ENEC revenues and $17 million ($14 million related to APCo) in construction surcharges annually for two years, effective July 2016. Additionally, APCo and WPCo agreed that a general rate case will not be filed before April 2018.

West Virginia Deferred Base Rate Increase

In May 2015, the WVPSC issued an order on APCo and WPCo's combined base rate case. The order included a delayed billing of $25 million ($22 million related to APCo) of the annual base rate increase to residential customers until July 2016. In June 2016, the WVPSC issued an order that approved recovery of the total deferred billing, including carrying charges through June 2018, totaling $29 million ($27 million related to APCo). Recovery was approved over two years, effective July 2016. Additionally, at the end of the two-year amortization, any over/under-recovery of the delayed billing will be included in the annual ENEC filing. The WVPSC also approved implementation of the prospective $25 million base rate increase effective July 2016.

2015 Virginia Regulatory Asset Proceeding

In 2015, the Virginia SCC initiated a proceeding to address the treatment of APCo's authorized regulatory assets. In September 2016, the Virginia SCC issued an order that approved the continued recovery through amortization of certain regulatory assets established prior to the period of frozen rates pursuant to the amended Virginia law (see "Virginia Legislation Affecting Biennial Reviews" below).

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 amendments provide 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 asset impairments related to new carbon emission guidelines issued by the Federal EPA.

In February 2016, certain APCo industrial customers filed a petition with the Virginia SCC requesting the issuance of a declaratory order that finds the amendments to Virginia law suspending biennial reviews unconstitutional and, accordingly, directs APCo to make biennial review filings beginning in 2016. In July 2016, the Virginia SCC issued an order that denied the petition. In July 2016, intervenors, including certain APCo industrial customers, filed an appeal of the order with the Supreme Court of Virginia. Management is unable to predict the outcome of these challenges to the Virginia legislation. If the biennial review process is reinstated in advance of March 2020, it could reduce future net income and cash flows and impact financial condition.

132

ETT Rate Matters (Applies to AEP)

ETT Interim Transmission Rates

Parent has a 50% equity ownership interest in ETT. Predominantly all of ETT's revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next filed base rate proceeding. As of September 30, 2016, AEP's share of ETT's cumulative revenues, subject to review, is estimated to be $545 million based upon interim rate increases received from 2009 through 2016. During a November 2015 open meeting at the PUCT, ETT committed to file a base rate case by February 2017. A base rate review could produce a refund if ETT incurs a disallowance of the transmission investment on which an interim increase was based. Management is unable to determine a range of potential losses that are reasonably possible of occurring. A revenue decrease, including a refund of interim transmission rates, could reduce future net income and cash flows and impact financial condition.

I&M Rate Matters (Applies to AEP and I&M)

Indiana Amended PJM Settlement Agreement

In September 2016, I&M and certain intervenors filed an amended settlement agreement with the IURC. This agreement amends a previously approved 2014 settlement agreement that addresses the recovery of 43.5% of certain transmission expenses through the Indiana PJM rider through 2017.

The amended agreement allows I&M to recover 100% of the Indiana jurisdictional share of these transmission expenses not recovered through base rates through the Indiana PJM rider, subject to a $109 million cap for the period January 2017 through June 2018. Beginning July 2018, I&M will be allowed to recover 100% of the Indiana jurisdictional share of these transmission expenses through the Indiana PJM rider, without a cap, until the issue is addressed by the IURC in a future proceeding, subject to the condition that I&M files a base rate case on or before January 2018. The amended agreement also provides for deferral of incremental vegetation management expenses over the period January 2017 through June 2018. Any vegetation management expenses deferred would reduce the cap for the transmission expenses described above. As part of the amended settlement, I&M agreed that it will not file a base rate case before July 2017 and will not implement new base rates prior to July 2018. A hearing at the IURC was held in October 2016.

Rockport Plant, Unit 2 Selective Catalytic Reduction (SCR)

In October 2016, I&M filed an application with the IURC for approval of a Certificate of Public Convenience and Necessity (CPCN) to install SCR technology at Rockport Plant, Unit 2 by December 2019. The equipment will allow I&M to reduce emissions of NO_x from Rockport Plant, Unit 2 in order for I&M to continue to operate that unit under current environmental requirements. The estimated cost of the SCR project is $274 million, excluding AFUDC, to be shared equally between I&M and AEGCo. The filing included a request for authorization for I&M to defer its Indiana jurisdictional ownership share of costs including investment carrying costs, depreciation over a 10-year life and other related expenses. I&M proposed recovery of these costs using the existing Clean Coal Technology Rider. The AEGCo ownership share of the proposed SCR project will be billable under the Rockport Unit Power Agreement to affiliates, including I&M, with I&M's share recoverable in its base rates.

KGPCo Rate Matters (Applies to AEP)

Kingsport Base Rate Case

In January 2016, KGPCo filed a request with the TRA to increase base rates by $12 million annually based upon a proposed return on common equity of 10.66%. In August 2016, the TRA approved a settlement agreement that included an $8 million annual increase in base rates with a 9.85% return on common equity effective September 2016.

OPCo Rate Matters (Applies to AEP and OPCo)

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 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. 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 2015, the Supreme Court of Ohio issued a decision that reversed the PUCO order on the carrying cost rate issue and remanded the matter back to the PUCO for reinstatement of the WACC rate. In June 2016, the PUCO approved OPCo's proposed increase to the PIRR rates, in accordance with the Supreme Court of Ohio ruling. The increase to PIRR rates included $146 million in additional carrying charges and the recovery of $40 million in additional under-recovered fuel costs resulting from a decrease in customer demand. The increase is effective July 2016 through December 2018. In July 2016, intervenors filed requests for rehearing with the PUCO, which the PUCO granted in August 2016.

If the PUCO determines after rehearing that the additional PIRR carrying charges are not recoverable, it could reduce future net income and cash flows and impact financial condition.

June 2012 – May 2015 ESP Including Capacity Charge

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

In July 2012, the PUCO issued an order in a separate capacity proceeding requiring OPCo to 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 included reserve margins, was approximately $34/MW day through May 2014 and $150/MW day from June 2014 through May 2015. In April 2016, the Supreme Court of Ohio issued two opinions related to the deferral of OPCo's capacity charges. In one of the opinions, the Supreme Court of Ohio ruled that the PUCO must reconsider an energy credit that was used to determine OPCo's authorized capacity deferral threshold of $188.88/MW day during the August 2012 through May 2015 period. The PUCO reduced OPCo's authorized capacity deferral threshold to $188.88/MW day largely due to an offset for an energy credit of $147.41/MW day. The Supreme Court of Ohio directed the PUCO to substantively address OPCo's arguments that the $147.41/MW day credit was overstated by approximately $100/MW day due to various inaccuracies affecting input data and assumptions.

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 2015, the PUCO issued an order that modified and approved OPCo's July 2014 application to collect the unrecovered portion of the deferred capacity costs. 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. As of September 30, 2016, OPCo's net deferred capacity costs balance was $239 million, including debt carrying costs, was recorded in Regulatory Assets on the balance sheet. In April 2016, the second Supreme Court of Ohio opinion rejected a portion of OPCo's RSR revenues collected during the period September 2012 through May 2015 and directed the PUCO to reduce OPCo's deferred capacity costs by these previously collected RSR revenues. The Supreme Court of

Ohio was not able to determine the amount of the reduction to OPCo's deferred capacity costs and remanded the issue to the PUCO to determine the appropriate reduction. As directed by the PUCO, in May 2016, OPCo submitted revised RSR tariffs that reflect the RSR being collected subject to refund.

In April 2016, the Supreme Court of Ohio also ruled favorably on OPCo's cross-appeal regarding a previously PUCO-imposed SEET threshold under the ESP and remanded this issue to the PUCO. See "Significantly Excessive Earnings Test Filings" section below.

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 November 2013, the PUCO issued an order approving OPCo's competitive bid process with modifications. 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 with the PUCO for the period August 2012 through May 2015. 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. Management believes that no over-recovery of costs has occurred and disagrees with the findings in the audit report.

In June 2016, OPCo filed a request with the PUCO that requested a consolidated procedural schedule to resolve interrelated proceedings including (a) OPCo's deferral of capacity costs for the period August 2012 through May 2015, (b) the implementation of OPCo's RSR and (c) the concerns related to the recovery of fixed fuel costs through both the FAC and the approved capacity charges. As part of the filing, OPCo requested that its net deferred capacity costs balance as of May 31, 2015 increase by $157 million, including carrying charges through September 2016. This net increase consists of a $327 million decrease due to the non-deferral portion of the RSR collections and an increase of $484 million for the correction of the energy credit. Recovery of the $157 million was requested to be effective October 2016 through December 2018. Additionally, OPCo filed testimony supporting the position that double recovery of fixed fuel costs could not have occurred because OPCo was unable to fully recover its capacity costs, which included fixed fuel costs, even with a corrected energy credit.

Due to the interrelated nature of the two Supreme Court of Ohio opinions that directly relate to OPCo's deferred capacity costs, management believes that the PUCO will rule upon these issues together. Further, management believes that the net impact of these issues will not result in a material future reduction of OPCo's net income. The recovery of fixed fuel costs will be addressed in a separate hearing scheduled for January 2017. See "2012 and 2013 Fuel Adjustment Clause Audits" section below.

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 Including PPA Application and Proposed ESP Extension through 2024

In 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 also included a 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 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, the PUCO issued an order on rehearing that increased the DIR rate caps and deferred ruling on all requests for rehearing related to the establishment of the PPA rider. In July 2015, the PUCO granted OPCo's and various intervenors' requests for rehearing related to the May 2015 order.

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

In March 2016, a contested stipulation agreement related to the PPA rider application was modified and approved by the PUCO. The approved PPA rider is effective April 2016 through May 2024, subject to audit and review by the PUCO. The stipulation agreement, as approved, included (a) an Affiliate PPA between OPCo and AGR to be included in the PPA rider, (b) OPCo's OVEC PPA to be included in the PPA rider, (c) potential additional contingent customer credits of up to $100 million to be included in the PPA rider over the final four years of the PPA rider and (d) the limitation that OPCo will not flow through any capacity performance penalties or bonuses through the PPA rider. Additionally, subject to cost recovery and PUCO approval, OPCo agreed to develop and implement, by 2021, a solar energy project(s) of at least 400 MW and a wind energy project(s) of at least 500 MW, with 100% of all output to be received by OPCo. AEP affiliates could own up to 50% of these solar and wind projects. OPCo agreed to file a carbon reduction plan with the PUCO by December 2016 that will focus on fuel diversification and carbon emission reductions.

In March 2016, a group of merchant generation owners filed a complaint at the FERC against PJM seeking revisions to the Minimum Offer Price Rule (MOPR) in PJM's tariff. Although the complaint requested the FERC act in advance of the May 2016 Base Residual Auction for the 2019/2020 delivery year, the complaint is still pending without a decision from the FERC. If approved as proposed, the revised MOPR could affect future bidding behavior for units with cost recovery mechanisms.

In April 2016, the FERC issued an order granting a January 2016 complaint filed against AGR and OPCo. The FERC order rescinded the waivers of the FERC's affiliate rules as to the affiliate PPA between AGR and OPCo. As a result, AGR and OPCo cannot implement the affiliate PPA without the FERC review, in accordance with FERC's rules governing affiliate transactions. As a result of the April 2016 FERC order, management does not intend to pursue the affiliate PPA.

In May 2016, OPCo filed an application for rehearing with the PUCO related to certain aspects of the March 2016 PUCO order. The application included a proposed OVEC-only PPA Rider that included an option for the rider to be bypassable. The proposed OVEC-only PPA Rider included (a) the elimination of the PUCO-imposed customer-specific rate impact cap of 5% through May 2018, (b) modifications to proportionately decrease the amount of the potential customer credits and (c) the inclusion of PJM capacity performance penalties within the PPA rider. Also in May 2016, intervenors filed applications for rehearing with the PUCO opposing the modified and approved stipulation agreement.

OPCo has the option to exercise its right to withdraw from the PPA stipulation if the PUCO does not accept the requested modifications.

Consistent with the terms of the modified and approved stipulation agreement, in May 2016, OPCo filed an amended ESP that proposed to extend the ESP through May 2024. The amended ESP included (a) an extension of the PPA rider, which includes only OPCo's entitlements to its ownership percentage of OVEC, (b) a proposed 10.41% return on common equity on capital costs for certain riders, (c) the continuation of riders previously approved in the June 2015 - May 2018 ESP, (d) proposed increases in rate caps related to OPCo's DIR and (e) the addition of various new riders, including a Generation Resource Rider. Based upon a September 2016 PUCO order, OPCo will refile its ESP extension application and supporting testimony in November 2016.

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

Background

Ohio law provides for the return of significantly excessive earnings to ratepayers upon PUCO review. Significantly excessive earnings are measured by whether the earned return on common equity of the electric distribution utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk.

2009 SEET Filing

In 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 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® (gridSMART® Phase II) program was filed with the PUCO which included a proposed project to satisfy the PUCO 2009 SEET directive. In April 2016, a stipulation agreement related to the gridSMART® Phase II program was filed with the PUCO. As part of the stipulation agreement, OPCo will invest at least $20 million over a six-year period for the installation of Volt VAR Optimization (VVO) technology on selected circuits throughout OPCo’s service territory. All parties to the stipulation agree that OPCo’s proposed VVO investment resolves OPCo’s outstanding obligation for renewable or similar investment associated with the PUCO’s 2009 SEET directive. A hearing at the PUCO on the stipulation was held in August 2016. A decision from the PUCO is pending.

2014 and 2015 SEET Filing

The PUCO established an annual SEET earnings threshold of 12% during the June 2012 - May 2015 ESP period. In May 2013, OPCo filed a cross appeal with the Supreme Court of Ohio, asserting that the SEET threshold would not be based on the earnings of comparable publicly traded companies as originally required by the SEET statute.

In April 2016, the Supreme Court of Ohio agreed with OPCo’s cross-appeal assertion that a 12% SEET threshold was not based on the applicable Ohio SEET statute. The Supreme Court of Ohio reversed the 12% threshold and remanded this issue to the PUCO. A decision from the PUCO is pending.

In June 2015 and May 2016, OPCo submitted its SEET filings for 2014 and 2015, respectively, with the PUCO. In August 2016, intervenors filed testimony recommending a revenue refund of approximately $20 million for 2014 and no refund for 2015 based upon a new approach to determine significantly excessive earnings that has not been previously approved by the PUCO. In September 2016, OPCo and the PUCO staff filed a stipulation agreement with the PUCO stating that no significantly excessive earnings occurred for 2014 or 2015. In September 2016, intervenors filed testimony opposing the stipulation agreement. Management believes its financial statements adequately address the impact of 2014 and 2015 SEET requirements.

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.

A hearing at the PUCO is scheduled for January 2017 to jointly review the recovery of fixed fuel costs as well as the open FAC audits discussed 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. In OPCo's 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. Through September 2009, the last month of the interim arrangement, OPCo had approximately $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 filing to approve recovery of the deferral under the interim agreement. Of the $64 million in deferred FAC costs, approximately 50% was related to Columbus Southern Power Company (CSPCo) and 50% related to OPCo, prior to the merger of CSPCo into OPCo in December 2011. CSPCo's portion of these deferred fuel costs has been recovered as a result of the previous collections of CSPCo fuel costs from ratepayers and the PUCO's 2013 order to apply CSPCo's 2010 excessive earnings to offset CSPCo's final deferred fuel balance. OPCo's share of Ormet deferred fuel costs continues to be recovered through OPCo's PIRR.

To the extent amounts discussed above are refunded to customers, it could reduce future net income and cash flows and impact financial condition.

PSO Rate Matters (Applies to AEP and PSO)

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 of 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 common equity of 10.5% effective in January 2016. The proposed $44 million increase related to environmental investments was effective in March 2016, after the Northeastern Plant, Unit 3 environmental controls were placed 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 September 30, 2016, PSO had incurred costs of $180 million and $43 million, including AFUDC, for Northeastern Plant, Unit 3 and Comanche Plant, respectively.

In addition, the filing also notified the OCC that the incremental replacement capacity and energy costs, including the first year effects of new PPAs, estimated to be $35 million, will be incurred related to the environmental compliance plan due to the closure of Northeastern Plant, Unit 4, which would be recovered through the FAC. In April 2016, Northeastern Plant, Unit 4 was retired. Upon retirement, $87 million was reclassified as Regulatory Assets on the balance sheet related to the net book value of Northeastern Plant, Unit 4. These regulatory assets are pending regulatory approval.

In October 2015, testimony was filed by OCC staff and intervenors with recommendations that included increases to base rates and/or the proposed environmental rider ranging from $10 million to $31 million, based upon returns on common equity ranging from 8.75% to 9.3%, and increases to depreciation expense ranging from $23 million to $46 million. Additionally, recommendations by certain intervenors included (a) no recovery of PSO's investment in Northeastern Plant, Unit 3 environmental controls, (b) no recovery of the plant balances at the time the units are retired in 2016 and 2026, (c) denial of returns on the book values after the retirement dates, or to be set at only the cost of debt, and (d) the disallowance of the capacity costs associated with the PPAs. Additionally, some intervenors recommended no change in depreciation lives for Northeastern Plant, Units 3 and 4. These units are currently being depreciated through 2040. Hearings at the OCC were held in December 2015. In January 2016, PSO implemented an interim annual base rate increase of $75 million. These interim rates are subject to refund pending a final order from the OCC related to the initial $137 million request.

In June 2016, an Administrative Law Judge (ALJ) issued a report related to PSO's base rate case filing and subsequently provided an additional supplemental report in August 2016. The ALJ recommended a 9.25% return on common equity. The ALJ found that PSO's environmental compliance plan is prudent and provided for cost recovery of the investment in this case with a recommended investment cap of $210 million on environmental controls installed at Northeastern Plant, Unit 3. Additionally, the ALJ recommendations included (a) a $14 million increase in depreciation expense, (b) continued depreciation of Northeastern Plant, Units 3 and 4 through 2040 (no accelerated depreciation), (c) return of, but no return on, the remaining net book value of Northeastern Plant, Unit 4, (d) elimination of the rider to recover advanced metering starting in December 2016, without inclusion in base rates and (e) elimination of the system reliability rider through consolidation in base rates, without addressing a transition for recovery of rider costs, including deferred costs. The estimated annual revenue increase resulting from the ALJ recommendations is approximately $47 million.

In June and September 2016, PSO, the OCC staff, the Attorney General and intervenors filed exceptions to the ALJ reports. PSO's response included numerous exceptions related to the ALJ recommendations including the lack of a return on the net book value of Northeastern Plant, Unit 4. The OCC staff filed exceptions that supported the full recovery of Northeastern Plant, Unit 4, including a return, and recommended a $32 million increase in annual revenues. An order from the OCC is anticipated in the fourth quarter of 2016.

If any of these costs, including a return on Northeastern Plant, Unit 4, are not recoverable, it could reduce future net income and cash flows and impact financial condition.

SWEPCo Rate Matters (Applies to AEP and SWEPCo)

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.

Upon rehearing in 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 was approximately $52 million. In May 2014, intervenors filed appeals of that order with the Texas District Court. In June 2014, SWEPCo intervened in those appeals. A hearing at the Texas District Court is scheduled for March 2017.

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, 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 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 upon 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 prudence review of the Turk Plant. The settlement also provided that the LPSC would review base rates in 2014 and 2015 and that SWEPCo would 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. A hearing at the LPSC related to the Turk Plant prudence review is scheduled for March 2017. 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 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 used to serve Louisiana customers in 2015 due to the expiration of a purchased 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, subject to staff review of the cost of service and prudence review of the Turk Plant. In July 2016, the LPSC approved a settlement agreement related to the staff review of the cost of service. A portion of the rates remain subject to refund based on the prudence review of the Turk Plant, see "2012 Louisiana Formula Rate Filing" above. Management believes its financial statements adequately address the impact of this settlement agreement. 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.

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 was 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.

140

Welsh Plant - Environmental Impact

Management currently estimates that the investment necessary to meet proposed environmental regulations through 2025 for Welsh Plant, Units 1 and 3 could cost approximately $850 million, excluding AFUDC. As of September 30, 2016, SWEPCo had incurred costs of $395 million, including AFUDC, and had remaining contractual construction obligations of $14 million related to these projects. As part of this investment, in 2016 SWEPCo completed construction of environmental control projects to meet Mercury and Air Toxics Standards for Welsh Plant, Units 1 and 3 at a cost of approximately $370 million, excluding AFUDC. Management continues to evaluate the impact of environmental rules and related project cost estimates. In March 2016, SWEPCo filed a request with the APSC to recover $69 million in environmental costs related to the Arkansas retail jurisdictional share of Welsh Plant, Units 1 and 3, which was approved by the APSC in August 2016. SWEPCo began recovering the Arkansas jurisdictional share of these costs in March 2016, subject to review in the next filed base rate proceeding. In September 2016, SWEPCo filed an additional request to increase the Arkansas retail jurisdictional share of the environmental investment by $10 million, for a total of $79 million. SWEPCo implemented the increase in September 2016. SWEPCo will seek recovery of the remaining project costs from customers at the state commissions and the FERC.

As of September 30, 2016, the net book value of Welsh Plant, Units 1 and 3 was $632 million, before cost of removal, including materials and supplies inventory and CWIP. In April 2016, Welsh Plant, Unit 2 was retired. Upon retirement, $76 million was reclassified as Regulatory Assets on the balance sheet related to the net book value of Welsh Plant, Unit 2 and the related asset retirement obligation costs. Management will seek recovery of the remaining regulatory assets in future rate proceedings.

If any of these costs are not recoverable, including retirement-related costs for Welsh Plant, Unit 2, it could reduce future net income and cash flows and impact financial condition.

TCC Rate Matters (Applies to AEP)

TCC Distribution Cost Recovery Factor (DCRF)

In July 2016, the PUCT approved a settlement agreement between TCC and intervenors related to TCC’s request for a DCRF rider to allow recovery of eligible net distribution investments. The settlement agreement included an annual revenue requirement of $45 million, effective September 2016. Amounts approved are subject to refund based upon a prudence review of the investments in TCC’s next base rate case.

TNC Rate Matters (Applies to AEP)

TNC Distribution Cost Recovery Factor (DCRF)

In July 2016, the PUCT approved a settlement agreement between TNC and intervenors related to TNC’s request for a DCRF rider to allow recovery of eligible net distribution investments. The settlement agreement included an annual revenue requirement of $11 million, effective September 2016. Amounts approved are subject to refund based upon a prudence review of the investments in TNC’s next base rate case.

FERC Rate Matters (Applies to AEP, APCo, I&M and OPCo)

PJM Transmission Rates

In June 2016, PJM transmission owners, including the AEP East Companies, and various state commissions filed a settlement agreement with the FERC to resolve outstanding issues related to cost responsibility for charges to transmission customers for certain transmission facilities that operate at or above 500 kV. In July 2016, certain parties filed comments at the FERC contesting the settlement agreement. Upon final FERC approval, PJM would implement a transmission enhancement charge adjustment through the PJM OATT, billable through 2025. Management expects that any refunds received would generally be returned to retail customers through existing state rider mechanisms.

FERC Transmission Complaint

In October 2016, several parties filed a joint complaint with the FERC that states the base return on common equity used by various AEP affiliates in calculating formula transmission rates under the PJM Open Access Transmission Tariff (OATT) is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. Management is reviewing the filing and evaluating a response to the complaint. If the FERC orders revenue reductions, including refunds from the date of filing, it could reduce future net income and cash flows and impact financial condition.

Other Rate Matters (Applies to AEP, PSO and SWEPCo)

SPP Open Access Transmission Tariff (OATT) Upgrade Costs

Under the SPP OATT, costs of sponsor-funded transmission upgrades may be recovered, in part, from SPP customers whose transmission service is dependent upon capacity enabled by the upgrades. SPP has not charged its customers any amounts attributable to these upgrades. Based upon preliminary information provided by SPP, in the third quarter of 2016, PSO and SWEPCo recognized a net unfavorable impact of $3 million and $4 million, respectively, related to the OATT upgrade costs. SPP expects to finalize the amounts due in the fourth quarter of 2016.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

The Registrants are subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Registrants' 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 the Registrants cannot be predicted. Management accrues contingent liabilities only when management concludes that it is both probable that a liability has been incurred at the date of the financial statements and the amount of loss can be reasonably estimated. When management determines that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, management discloses such contingencies and the possible loss or range of loss if such estimate can be made. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the maximum possible loss exposure. Circumstances change over time and actual results may vary significantly from estimates.

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 2015 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 unless specified below. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit (Applies to AEP, APCo, I&M and OPCo)

Standby letters of credit are entered into with third parties. These letters of credit are issued in the ordinary course of business and cover items such as natural gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

AEP has two revolving credit facilities totaling $3.5 billion. In June 2016, the $1.75 billion credit facility due in June 2017 was amended to $3 billion due in June 2021, under which up to $1.2 billion may be issued as letters of credit on behalf of subsidiaries. Also in June 2016, the $1.75 billion credit facility due in July 2018 was amended to $500 million due in June 2018. As of September 30, 2016, no letters of credit were issued under the $3 billion revolving credit facility.

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP also issues letters of credit on behalf of subsidiaries under four uncommitted facilities totaling $300 million. As of September 30, 2016, the Registrants' maximum future payments for letters of credit issued under the uncommitted facilities were as follows:

Company	Amount (in millions)	Maturity
AEP	$ 147.2	October 2016 to September 2017
OPCo	4.2	September 2017

The Registrants have $291 million of variable rate Pollution Control Bonds supported by $295 million of bilateral letters of credit as follows:

Company	Pollution Control Bonds	Bilateral Letters of Credit	Maturity of Bilateral Letters of Credit
	(in millions)		
AEP	$ 291.4	$ 294.7	March 2017 to July 2017
APCo	104.4	105.6	March 2017
I&M	77.0	77.9	March 2017

143

Guarantees of Third-Party Obligations (Applies to AEP and 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 September 30, 2016, SWEPCo has collected $68 million through a rider for final mine closure and reclamation costs, of which $15 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $53 million is recorded in Asset Retirement Obligations on SWEPCo’s 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

The Registrants 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 September 30, 2016, 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. 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.

Master Lease Agreements

The Registrants 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 Registrants 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 September 30, 2016, the maximum potential loss by Registrants for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term is as follows:

Company	Maximum Potential Loss (in millions)
AEP	$ 36.8
APCo	5.5
I&M	3.4
OPCo	5.8
PSO	3.0
SWEPCo	3.5

Railcar Lease (Applies to AEP, I&M and SWEPCo)

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 $9 million and $11 million for I&M and SWEPCo, respectively, for the remaining railcars as of September 30, 2016.

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% of the projected fair value of the equipment under the current five-year lease term to 77% at the end of the 20-year term. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. The maximum potential losses related to the guarantee are $9 million and $10 million for I&M and SWEPCo, respectively, as of September 30, 2016, 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.

AEPRO Boat and Barge Leases (Applies to AEP)

In October 2015, AEP signed a Purchase and Sale Agreement to sell its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party. The sale closed in November 2015. See “AEPRO (Corporate and Other Segment)” section of Note 6. Certain of the boat and barge leases acquired by the nonaffiliated party are subject to an AEP guarantee in favor of the lessor, ensuring future payments under such leases with maturities up to 2027. As of September 30, 2016, the maximum potential amount of future payments required under the guaranteed leases was $87 million. In certain instances, AEP has no recourse against the nonaffiliated party if required to pay a lessor under a guarantee, but AEP would have access to sell the leased assets in order to recover payments made by AEP under the guarantee. As of September 30, 2016, AEP’s boat and barge lease guarantee liability was $14 million, of which $3 million was recorded in Other Current Liabilities and $11 million was recorded in Deferred Credits and Other Noncurrent Liabilities on AEP’s balance sheets.

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, the generation plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. The Registrants 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 was reduced. As of September 30, 2016, I&M’s accrual for all of these sites is $8 million. As the remediation work is completed, I&M’s cost may change as new information becomes available concerning either the level of contamination at the sites or changes in the scope of remediation. Management cannot predict the amount of additional cost, if any.

NUCLEAR CONTINGENCIES (APPLIES TO AEP AND I&M)

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission (NRC). 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 (Applies to AEP and 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 plaintiff's claims. Several claims remained, 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. The plaintiff subsequently filed an amended complaint to add another claim under the lease and also filed a motion for partial summary judgment. In November 2015, AEGCo and I&M filed a motion to strike the plaintiff's motion for partial judgment and filed a motion to dismiss the case for failure to state a claim. In March 2016, the court entered an opinion and order in favor of AEGCo and I&M, dismissing certain of the plaintiffs' claims for breach of contract and dismissing claims for breach of implied covenant of good faith and fair dealing, and further dismissing plaintiffs' claim for indemnification of costs. By the same order, the court permitted plaintiffs to move forward with their claim that AEGCo and I&M failed to exercise prudent utility practices in the maintenance and operation of Rockport Plant, Unit 2. In April 2016, the plaintiffs filed a notice of voluntary dismissal of all remaining claims with prejudice and the court subsequently entered a final judgment. In May 2016, Plaintiffs filed a notice of appeal on whether AEGCo and I&M are in breach of certain contract provisions that Plaintiffs allege operate to protect the Plaintiffs' residual interests in the unit and whether the trial court erred in dismissing Plaintiffs' claims that AEGCo and I&M breached the covenant of good faith and fair dealing. This matter is currently pending before the U.S. Court of Appeals for the Sixth Circuit. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Natural Gas Markets Lawsuits (Applies to AEP)

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. AEP settled, received summary judgment or was 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 were remanded to the district court for further proceedings. There are four pending cases, of which three are class actions and one is a single plaintiff case. A tentative settlement has been reached in the three class actions. This settlement, once finalized, will be subject to court approval. In May 2016, the district court dismissed the remaining case. Management will continue to defend any appeal of that matter. Management is unable to determine the amount of potential additional loss that is reasonably possible of occurring.

Wage and Hours Lawsuit (Applies to AEP and 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 were 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. In February 2016, PSO filed a motion for summary judgment. In April 2016, by opinion and order, the court granted PSO's motion for summary judgment and dismissed the case. Plaintiffs did not appeal the dismissal and the court's order is final.

Gavin Landfill Litigation (Applies to AEP and 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. As a result of OPCo transferring its generation assets to AGR, the outcome of this complaint will be the responsibility of AGR. 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. In August 2015, the court denied the motion. Management appealed that decision to the West Virginia Supreme Court. In February 2016, a decision was issued by the court denying the appeal and remanding the case to the West Virginia Mass Litigation Panel, which typically handles multi-plaintiff cases, rather than back to the Mason County, West Virginia Circuit Court. Defendants' petition for rehearing was denied by the West Virginia Supreme Court. Management will continue to defend against the claims. Management believes the provision recorded is adequate. Management is unable to determine a range of potential additional losses that are reasonably possible of occurring.

6. DISPOSITIONS, ASSETS AND LIABILITIES HELD FOR SALE AND IMPAIRMENTS

The disclosures in this note apply to AEP only unless indicated otherwise.

DISPOSITIONS

2016

Tanners Creek Plant (Vertically Integrated Utilities Segment) (Applies to AEP and I&M)

In October 2016, I&M sold its retired Tanners Creek plant site including its associated asset retirement obligations (AROs) to a nonaffiliated party. I&M paid $92 million and the nonaffiliated party took ownership of the Tanners Creek plant site assets and assumed responsibility for environmental liabilities and AROs, including ash pond closure, asbestos abatement and decommissioning and demolition. I&M does not expect to record a gain or loss related to this sale and will address recovery of Tanner's Creek deferred costs in future rate proceedings. If any of the costs associated with Tanner's Creek are not recoverable, it could reduce future net income and impact financial condition.

2015

Muskingum River Plant (Generation & Marketing Segment)

In August 2015, AGR sold its retired Muskingum River Plant site including its associated asset retirement obligations to a nonaffiliated party. AGR paid $48 million and the nonaffiliated party took ownership of the Muskingum River Plant site assets and assumed responsibility for environmental liabilities and AROs, including ash pond closure, asbestos abatement and decommissioning and demolition. As a result of the sale, a net gain of $32 million was recognized and recorded in Other Operation on the statements of operations. The cash paid was recorded in Operating Activities on the statements of cash flows.

AEPRO (Corporate and Other Segment)

In October 2015, AEP signed a Purchase and Sale Agreement to sell its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party. The sale closed in November 2015. The nonaffiliated party acquired AEPRO by purchasing all of the common stock of AEP Resources, Inc., the parent company of AEPRO. The nonaffiliated party assumed certain assets and liabilities of AEPRO, excluding the equity method investment in International Marine Terminals, LLC, pension and benefit assets and liabilities and debt obligations. Prior to the closing of the sale, AEP retired the debt obligations of AEPRO. AEP retained ownership of its captive barge fleet that delivers coal to the company's regulated coal-fueled power plant units owned or leased by AEGCo, APCo, I&M, KPCo and WPCo. AEP signed a contract with the nonaffiliated party to dispatch and schedule its captive barge fleet for the company's regulated coal-fueled power plant units. AEP also has a separate contract with the nonaffiliated party to barge coal for AGR. These agreements with the nonaffiliated party extend through the end of 2016.

Results of operations of AEPRO have been classified as discontinued operations on AEP's statements of operations for the three and nine months ended September 30, 2015, as shown in the following table:

	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2015
	(in millions)	
Other Revenues	$129.1	$ 372.2
Other Operation Expense	96.7	273.1
Maintenance Expense	4.2	19.9
Depreciation and Amortization Expense	8.8	26.9
Taxes Other Than Income Taxes	2.7	9.9
Total Expenses	112.4	329.8
Other Income (Expense)	(5.4)	(14.5)
Pretax Income of Discontinued Operations	11.3	27.9
Income Tax Expense	3.6	9.7
Equity Earnings of Unconsolidated Subsidiaries	0.1	—
Total Income on Discontinued Operations as Presented on the Statements of Operations	$7.8	$ 18.2

In the second quarter of 2016, AEP recorded a $3 million loss related to the final accounting for the sale of AEPRO, which was recorded in Income (Loss) from Discontinued Operations, Net of Tax, on AEP's statements of operations.

ASSETS AND LIABILITIES HELD FOR SALE

2016

Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)
During the third quarter of 2016, AEP received bids and selected a buyer, received approval from AEP's Board of Directors and signed a Purchase and Sale Agreement to sell AGR's Gavin, Waterford and Darby plants as well as AEGCo's Lawrenceburg plant totaling 5,326 MW of competitive generation assets for approximately $2.2 billion to a nonaffiliated party. The sale is subject to regulatory approvals from the FERC, the IURC and federal clearance pursuant to the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR). In October 2016, the Federal Trade Commission granted the sale early termination of the HSR waiting period thereby satisfying the HSR conditions to close the transaction. The sale is expected to close in the first quarter of 2017.

Upon evaluation, management concluded that the disposal group met the classification as held for sale in the third quarter of 2016. Accordingly, the four plants' assets and liabilities have been recorded as Assets Held for Sale and Liabilities Held for Sale on AEP's balance sheet as of September 30, 2016 and as shown in the table below. The Income from Continuing Operations before Income Tax Expense and Equity Earnings of the four plants was approximately $116 million and $118 million for the three months ended September 30, 2016 and 2015, respectively, and $312 million and $404 million for the nine months ended September 30, 2016 and 2015, respectively.

Assets:	September 30, 2016 (in millions)
Fuel	$ 139.7
Materials and Supplies	48.7
Property, Plant and Equipment - Net	1,726.5
Other Class of Assets That Are Not Major	0.4
Total Assets Classified as Held for Sale on the Balance Sheets	$ 1,915.3
Liabilities:	
Long-term Debt	$ 134.8
Waterford Plant Upgrade Liability	53.1
Asset Retirement Obligations	36.3
Other Classes of Liabilities That Are Not Major	6.8
Total Liabilities Classified as Held for Sale on the Balance Sheets	$ 231.0

IMPAIRMENTS

2016

Merchant Generating Assets (Generation & Marketing Segment)

In September 2016, due to AEP's ongoing evaluation of strategic alternatives for its merchant generation assets, declining forecasts of future energy and capacity prices, and a decreasing likelihood of cost recovery through regulatory proceedings or legislation in the state of Ohio providing for the recovery of AEP's existing Ohio merchant generation assets, AEP performed an impairment analysis at the unit level on the remaining merchant generation assets in accordance with accounting guidance for impairments of long-lived assets. Cardinal Unit 1, a 43.5% interest in Conesville Unit 4, Conesville Units 5-6, a 26% interest in Stuart Units 1-4, a 25.4% interest in Zimmer Unit 1, and a 54.7% interest in Oklaunion (collectively the "Merchant Coal-Fired Generation Assets") were subject to this analysis. Additionally, Racine Hydroelectric Plant ("Racine"), Putnam and I&M's Price River coal reserves ("Coal Reserves") and Desert Sky and Trent Wind Farms ("Wind Farms") were also included in this analysis. For the Merchant Coal-Fired Generation Assets, Racine and the Wind Farms, AEP performed step one of the impairment analysis using undiscounted cash flows for the estimated useful lives of the assets based upon energy and capacity price curves, as applicable, which were developed internally with both observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. The step one analysis concluded the book value of Racine would be recovered and the book value of the remaining assets would not be recovered.

AEP performed step two of the impairment analysis on the Merchant Coal-Fired Generation Assets using a ten-year discounted cash flow model based upon forecasted energy and capacity price curves, which were developed internally using both observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. The step two analysis resulted in projected negative cash flows. Based on this result, coupled with the significant capital investments necessary to comply with environmental rules to allow the Merchant Coal-Fired Generation Assets to operate to the end of their currently estimated depreciable lives and the joint-ownership structure of these facilities, management determined the fair value of these assets was $0. AEP performed step two of the impairment analysis on the Wind Farms using a ten-year discounted cash flow model utilizing forecasted energy price curves, which were developed internally using both observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. The results concluded the Wind Farms were also impaired.

For the Coal Reserves, AEP performed step one of the impairment analysis and concluded the book value of the assets would not be recovered. Step two of the impairment analysis on the Coal Reserves was performed using a market approach with Level 3 unobservable inputs. The results concluded the Coal Reserves were also impaired.
Based on the impairment analysis performed, in the third quarter of 2016, AEP recorded a pretax impairment of $2.3 billion in Asset Impairments and Other Related Charges on the statement of operations. See the table below for additional information.

Impaired Assets	Book Value	Fair Value	Impairment
	(in millions)		
Merchant Coal-Fired Generation Assets	$2,139.4	$—	$ 2,139.4
Trent and Desert Sky Wind Farms	118.7	46.0	72.7
Coal Reserves (a)	56.6	3.8	52.8
Total	$2,314.7	$49.8	$ 2,264.9

(a) Includes the $11 million book value of I&M’s Price River Coal Reserves which were fully impaired. This $11 million impairment is reflected in the Vertically Integrated Utilities Segment.

7. BENEFIT PLANS

The disclosures in this note apply to all Registrants unless indicated otherwise.

AEP sponsors a qualified pension plan and two unfunded nonqualified pension plans. Substantially all AEP employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. AEP also sponsors 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 net periodic benefit cost (credit) by Registrant for the plans for the three and nine months ended September 30, 2016 and 2015:

AEP

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Service Cost	$21.4	$23.4	$2.6	$3.1
Interest Cost	52.9	51.3	15.3	14.2
Expected Return on Plan Assets	(70.1)	(68.6)	(26.8)	(27.7)
Amortization of Prior Service Cost (Credit)	0.6	0.5	(17.3)	(17.3)
Amortization of Net Actuarial Loss	21.0	26.7	7.8	4.7
Net Periodic Benefit Cost (Credit)	$25.8	$33.3	$(18.4)	$(23.0)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Service Cost	$64.3	$70.1	$7.7	$9.2
Interest Cost	158.7	153.9	45.7	42.6
Expected Return on Plan Assets	(210.2)	(206.0)	(80.3)	(83.3)
Amortization of Prior Service Cost (Credit)	1.7	1.7	(51.8)	(51.8)
Amortization of Net Actuarial Loss	62.9	80.3	23.5	14.1
Net Periodic Benefit Cost (Credit)	$77.4	$100.0	$(55.2)	$(69.2)

APCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Service Cost	$2.1	$2.1	$0.2	$0.3
Interest Cost	6.8	6.7	2.7	2.5
Expected Return on Plan Assets	(8.8)	(8.7)	(4.3)	(4.5)
Amortization of Prior Service Credit	—	—	(2.5)	(2.5)
Amortization of Net Actuarial Loss	2.6	3.5	1.4	0.9
Net Periodic Benefit Cost (Credit)	$2.7	$3.6	$(2.5)	$(3.3)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Service Cost	$6.1	$6.5	$0.7	$0.9
Interest Cost	20.4	20.1	8.1	7.7
Expected Return on Plan Assets	(26.5)	(26.2)	(13.0)	(13.6)
Amortization of Prior Service Cost (Credit)	0.1	0.1	(7.5)	(7.5)
Amortization of Net Actuarial Loss	8.0	10.4	4.1	2.7
Net Periodic Benefit Cost (Credit)	$8.1	$10.9	$(7.6)	$(9.8)

I&M

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Service Cost	$3.1	$3.3	$0.4	$0.4
Interest Cost	6.3	6.1	1.7	1.6
Expected Return on Plan Assets	(8.4)	(8.1)	(3.2)	(3.3)
Amortization of Prior Service Credit	—	—	(2.4)	(2.4)
Amortization of Net Actuarial Loss	2.5	3.1	0.9	0.5

Net Periodic Benefit Cost (Credit)	$3.5	$4.4	$(2.6)	$(3.2)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Service Cost	$9.2	$9.7	$1.1	$1.2
Interest Cost	19.0	18.3	5.2	4.8
Expected Return on Plan Assets	(25.2)	(24.3)	(9.6)	(9.9)
Amortization of Prior Service Cost (Credit)	0.1	0.1	(7.1)	(7.1)
Amortization of Net Actuarial Loss	7.4	9.4	2.8	1.5
Net Periodic Benefit Cost (Credit)	$10.5	$13.2	$(7.6)	$(9.5)

OPCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Service Cost	$1.6	$1.6	$0.2	$0.2
Interest Cost	5.1	5.1	1.8	1.6
Expected Return on Plan Assets	(6.9)	(6.8)	(3.3)	(3.4)
Amortization of Prior Service Credit	—	—	(1.7)	(1.8)
Amortization of Net Actuarial Loss	2.1	2.6	0.9	0.6
Net Periodic Benefit Cost (Credit)	$1.9	$2.5	$(2.1)	$(2.8)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Service Cost	$4.9	$5.0	$0.6	$0.6
Interest Cost	15.4	15.2	5.3	4.8
Expected Return on Plan Assets	(20.8)	(20.6)	(9.7)	(10.1)
Amortization of Prior Service Cost (Credit)	0.1	0.1	(5.2)	(5.2)
Amortization of Net Actuarial Loss	6.1	7.9	2.8	1.6
Net Periodic Benefit Cost (Credit)	$5.7	$7.6	$(6.2)	$(8.3)

PSO

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Service Cost	$1.5	$1.6	$0.2	$0.2
Interest Cost	2.8	2.7	0.8	0.8
Expected Return on Plan Assets	(3.9)	(3.8)	(1.5)	(1.5)
Amortization of Prior Service Cost (Credit)	0.1	0.1	(1.1)	(1.1)

Amortization of Net Actuarial Loss	1.1	1.5	0.4	0.2
Net Periodic Benefit Cost (Credit)	$1.6	$2.1	$(1.2)	$(1.4)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Service Cost	$4.6	$4.8	$0.5	$0.5
Interest Cost	8.4	8.2	2.4	2.3
Expected Return on Plan Assets	(11.6)	(11.4)	(4.5)	(4.7)
Amortization of Prior Service Cost (Credit)	0.2	0.2	(3.2)	(3.2)
Amortization of Net Actuarial Loss	3.3	4.3	1.3	0.7
Net Periodic Benefit Cost (Credit)	$4.9	$6.1	$(3.5)	$(4.4)

SWEPCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Service Cost	$2.0	$2.2	$0.2	$0.2
Interest Cost	3.1	2.9	0.9	0.8
Expected Return on Plan Assets	(4.0)	(4.0)	(1.7)	(1.7)
Amortization of Prior Service Credit	—	—	(1.3)	(1.3)
Amortization of Net Actuarial Loss	1.2	1.5	0.5	0.3
Net Periodic Benefit Cost (Credit)	$2.3	$2.6	$(1.4)	$(1.7)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Service Cost	$6.1	$6.3	$0.6	$0.6
Interest Cost	9.3	8.8	2.7	2.5
Expected Return on Plan Assets	(12.3)	(12.0)	(5.0)	(5.2)
Amortization of Prior Service Cost (Credit)	0.2	0.2	(3.9)	(3.8)
Amortization of Net Actuarial Loss	3.6	4.5	1.5	0.8
Net Periodic Benefit Cost (Credit)	$6.9	$7.8	$(4.1)	$(5.1)

8. BUSINESS SEGMENTS

The disclosures in this note apply to all Registrants unless indicated otherwise.

AEP's Reportable Segments

AEP's primary business is the generation, transmission and distribution of electricity. Within its Vertically Integrated Utilities segment, AEP centrally dispatches generation assets and manages its 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.

AEP's 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 AEP's wholly-owned transmission-only subsidiaries and transmission-only joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

Generation & Marketing

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

The remainder of AEP's 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, Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs. With the sale of AEPRO in November 2015, the activities related to the AEP River Operations segment have been moved to Corporate and Other for the periods presented. See "AEPRO (Corporate and Other)" section of Note 6 for additional information.

The tables below present AEP's reportable segment income statement information for the three and nine months ended September 30, 2016 and 2015 and reportable segment balance sheet information as of September 30, 2016 and December 31, 2015. These amounts include certain estimates and allocations where necessary.

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Three Months Ended September 30, 2016							
Revenues from:							
External Customers	$2,538.3	$ 1,245.4	$ 39.5	$823.3	$ 5.7	$ —	$ 4,652.2
Other Operating Segments	18.0	30.2	92.9	36.1	19.1	(196.3)	—
Total Revenues	$2,556.3	$ 1,275.6	$ 132.4	$859.4	$ 24.8	$ (196.3)	$ 4,652.2
Income (Loss) from Continuing Operations	$343.4	$ 155.5	$ 69.5	$(1,369.2)	$ 36.6	$ —	$ (764.2)
Income from Discontinued Operations, Net of Tax	—	—	—	—	—	—	—
Net Income (Loss)	$343.4	$ 155.5	$ 69.5	$(1,369.2)	$ 36.6	$ —	$ (764.2)

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Three Months Ended September 30, 2015							
Revenues from:							
External Customers	$2,435.8	$ 1,163.6	$ 26.9	$801.8	$ 3.3	$ —	$ 4,431.4
Other Operating Segments	35.7	25.0	60.6	34.2	20.5	(176.0)	—
Total Revenues	$2,471.5	$ 1,188.6	$ 87.5	$836.0	$ 23.8	$ (176.0)	$ 4,431.4
Income (Loss) from Continuing Operations	$274.5	$ 113.0	$ 45.9	$91.6	$ (13.2)	$ —	$ 511.8
Income from Discontinued Operations, Net of Tax	—	—	—	—	7.8	—	7.8
Net Income (Loss)	$274.5	$ 113.0	$ 45.9	$91.6	$ (5.4)	$ —	$ 519.6

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Nine Months Ended September 30, 2016							
Revenues from:							
External Customers	$6,864.6	$ 3,398.9	$ 110.1	$2,192.5	$ 23.9	$ —	$ 12,590.0
Other Operating Segments	63.2	69.6	272.6	98.7	55.2	(559.3)	—
Total Revenues	$6,927.8	$ 3,468.5	$ 382.7	$2,291.2	$ 79.1	$ (559.3)	$ 12,590.0
Income (Loss) from Continuing Operations	$832.6	$ 388.1	$ 209.5	$(1,248.8)	$ 63.9	$ —	$ 245.3
Loss from Discontinued Operations, Net of Tax	—	—	—	—	(2.5)	—	(2.5)
Net Income (Loss)	$832.6	$ 388.1	$ 209.5	$(1,248.8)	$ 61.4	$ —	$ 242.8

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Nine Months Ended September 30, 2015							
Revenues from:							
External Customers	$7,081.8	$ 3,377.9	$ 74.1	$2,288.6	$ 16.1	$ —	$ 12,838.5
Other Operating Segments	77.3	141.5	170.8	518.1	57.8	(965.5)	—
Total Revenues	$7,159.1	$ 3,519.4	$ 244.9	$2,806.7	$ 73.9	$ (965.5)	$ 12,838.5
Income (Loss) from Continuing Operations	$782.7	$ 287.8	$ 147.7	$360.3	$ (15.1)	$ —	$ 1,563.4
Income from Discontinued Operations, Net of Tax	—	—	—	—	18.2	—	18.2
Net Income	$782.7	$ 287.8	$ 147.7	$360.3	$ 3.1	$ —	$ 1,581.6

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments		Consolidated
	(in millions)							
September 30, 2016								
Total Property, Plant and Equipment	$41,015.6	$ 14,438.4	$ 4,896.4	$ 234.3	$368.6	$(353.5	)(b)	$ 60,599.8
Accumulated Depreciation and Amortization	12,549.8	3,647.4	88.2	44.2	192.1	(184.1	)(b)	16,337.6
Total Property Plant and Equipment - Net	$28,465.8	$ 10,791.0	$ 4,808.2	$ 190.1	$176.5	$(169.4	)(b)	$ 44,262.2
Assets Held for Sale	$—	$ —	$ —	$ 1,915.3	$—	$—		$ 1,915.3
Total Assets	$36,924.3	$ 14,155.7	$ 5,780.5	$ 3,176.6	$21,772.4	$(20,367.5	)(b)(c)	$ 61,442.0
Long-term Debt Due Within One Year:								
Non-Affiliated	$1,611.0	$ 268.3	$ —	$ 505.2	$0.3	$—		$ 2,384.8
Long-term Debt:								
Affiliated	20.0	—	—	32.2	—	(52.2	)	—
Non-Affiliated	10,067.3	4,745.3	1,660.4	—	846.9	—		17,319.9
Total Long-term Debt	$11,698.3	$ 5,013.6	$ 1,660.4	$ 537.4	$847.2	$(52.2	)	$ 19,704.7
Liabilities Held for Sale	$—	$ —	$ —	$ 231.0	$—	$—		$ 231.0

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments		Consolidated
	(in millions)							
December 31, 2015								
Total Property, Plant and Equipment	$40,130.3	$ 13,840.5	$ 3,977.6	$ 7,461.3	$350.9	$(279.2	)(b)	$ 65,481.4
Accumulated Depreciation and Amortization	12,335.0	3,529.2	52.3	3,367.0	176.9	(112.2	)(b)	19,348.2
Total Property Plant and Equipment - Net	$27,795.3	$ 10,311.3	$ 3,925.3	$ 4,094.3	$174.0	$(167.0	)(b)	$ 46,133.2
Total Assets	$35,792.3	$ 14,640.2	$ 5,012.1	$ 5,414.5	$21,907.4	$(21,083.4	)(b)(c)	$ 61,683.1
Long-term Debt Due Within One Year:								
Non-Affiliated	$935.4	$ 824.7	$ —	$ 71.6	$0.1	$—		$ 1,831.8

Long-term Debt:							
Affiliated	20.0	—	—	32.2	—	(52.2)	—
Non-Affiliated	9,833.0	4,776.8	1,648.4	639.5	843.2	—	17,740.9
Total Long-term Debt	$10,788.4	$5,601.5	$1,648.4	$743.3	$843.3	$(52.2)	$19,572.7

(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, interest expense and discontinued operations of AEPRO and other nonallocated costs.

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

(c) 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.

Registrant Subsidiaries' Reportable Segments

The Registrant Subsidiaries each have one reportable segment, an integrated electricity generation, transmission and distribution business, except OPCo, which has an electricity transmission and distribution business. 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.

9. DERIVATIVES AND HEDGING

The disclosures in this note apply to all Registrants unless indicated otherwise.

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of AEP subsidiaries, including the Registrant Subsidiaries. AEPEP is agent for and transacts on behalf of other AEP subsidiaries.

The Registrants are exposed to certain market risks as major power producers and participants in the electricity, capacity, natural gas, coal and emission allowance markets. These risks include commodity price risks which may be subject to capacity 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 Registrants due to changes in the underlying market prices or rates. Management utilizes derivative instruments to manage these risks.

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 which focus on seizing market opportunities to create value driven by expected changes in the market prices of the commodities. To accomplish these objectives, the Registrants 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.

The Registrants utilize power, capacity, 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. The Registrants utilize interest rate derivative contracts in order to manage the interest rate exposure associated with the commodity portfolio. For disclosure purposes, such risks are grouped as “Commodity,” as these risks are related to energy risk management activities. The Registrants also utilize derivative contracts to manage 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, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors.

The following tables represent the gross notional volume of the Registrants' outstanding derivative contracts as of September 30, 2016 and December 31, 2015:

Notional Volume of Derivative Instruments
September 30, 2016

Primary Risk Exposure	Unit of Measure	AEP	APCo	I&M	OPCo	PSO	SWEPCo
		(in millions)					
Commodity:							
Power	MWhs	398.7	66.4	22.4	11.3	18.3	21.8
Coal	Tons	2.1	—	0.7	—	—	1.4
Natural Gas	MMBtus	37.3	—	—	—	—	—
Heating Oil and Gasoline	Gallons	6.9	1.3	0.6	1.5	0.8	0.9
Interest Rate	USD	$82.2	$ 0.1	$0.1	$ —	$ —	$ —
Interest Rate and Foreign Currency	USD	$505.2	$ —	$—	$ —	$ —	$ —

Notional Volume of Derivative Instruments
December 31, 2015

Primary Risk Exposure	Unit of Measure	AEP	APCo	I&M	OPCo	PSO	SWEPCo
		(in millions)					
Commodity:							
Power	MWhs	317.8	40.9	22.8	13.3	11.3	14.0
Coal	Tons	4.4	—	1.6	—	—	2.8
Natural Gas	MMBtus	38.2	0.3	0.2	—	0.2	0.2
Heating Oil and Gasoline	Gallons	7.4	1.4	0.7	1.6	0.8	0.9
Interest Rate	USD	$113.5	$ 2.4	$1.6	$ —	$ —	$ —
Interest Rate and Foreign Currency	USD	$560.3	$ —	$—	$ —	$ —	$ —

Fair Value Hedging Strategies (Applies to AEP)

Parent enters 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 exposure to interest rate risk by converting a portion of fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives may be designated as fair value hedges.

Cash Flow Hedging Strategies

The Registrants utilize cash flow hedges on 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 Registrants do not hedge all commodity price risk.

The Registrants utilize a variety of interest rate derivative transactions in order to manage interest rate risk exposure. The Registrants also utilize interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. The Registrants do not hedge all interest rate exposure.

At times, the Registrants 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, the Registrants may utilize foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. The Registrants 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 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 the derivative instruments, the Registrants 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 Registrants 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 Registrants are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the September 30, 2016 and December 31, 2015 balance sheets, the Registrants 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:

	September 30, 2016		December 31, 2015	
Company	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities
	(in millions)			
AEP	$7.1	$ 36.0	$ 5.8	$ 44.4
APCo	0.1	0.1	—	3.1
I&M	—	0.3	—	0.6
OPCo	—	—	—	0.5
PSO	—	—	—	0.3
SWEPCo	—	—	—	0.3

163

The following tables represent the gross fair value of the Registrants' derivative activity on the balance sheets as of September 30, 2016 and December 31, 2015:

AEP

Fair Value of Derivative Instruments
September 30, 2016

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)					
Current Risk Management Assets	$267.0	$8.0	$ 0.3	$ 275.3	$(164.5)	$ 110.8
Long-term Risk Management Assets	364.2	5.4	—	369.6	(57.9)	311.7
Total Assets	631.2	13.4	0.3	644.9	(222.4)	422.5
Current Risk Management Liabilities	241.5	6.6	0.2	248.3	(169.0)	79.3
Long-term Risk Management Liabilities	273.3	48.7	0.3	322.3	(82.3)	240.0
Total Liabilities	514.8	55.3	0.5	570.6	(251.3)	319.3
Total MTM Derivative Contract Net Assets (Liabilities)	$116.4	$(41.9)	$ (0.2)	$ 74.3	$28.9	$ 103.2

AEP

Fair Value of Derivative Instruments
December 31, 2015

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)					
Current Risk Management Assets	$368.8	$8.2	$ 0.1	$ 377.1	$(242.7)	$ 134.4
Long-term Risk Management Assets	364.8	11.7	—	376.5	(54.7)	321.8
Total Assets	733.6	19.9	0.1	753.6	(297.4)	456.2
Current Risk Management Liabilities	347.0	9.1	0.3	356.4	(269.3)	87.1
Long-term Risk Management Liabilities	223.3	19.3	3.2	245.8	(66.7)	179.1

Total Liabilities	570.3	28.4	3.5	602.2	(336.0)	266.2
Total MTM Derivative Contract Net Assets (Liabilities)	$ 163.3	$ (8.5)	$ (3.4)	$ 151.4	$ 38.6	$ 190.0

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

(b) Amounts 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.

APCo

Fair Value of Derivative Instruments
September 30, 2016

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets - Nonaffiliated	$11.0	$ (7.8)	$ 3.2
Long-term Risk Management Assets - Nonaffiliated	1.0	(0.8)	0.2
Total Assets	12.0	(8.6)	3.4
Current Risk Management Liabilities - Nonaffiliated	18.5	(7.8)	10.7
Long-term Risk Management Liabilities - Nonaffiliated	1.1	(0.8)	0.3
Total Liabilities	19.6	(8.6)	11.0
Total MTM Derivative Contract Net Liabilities	$(7.6)	$ —	$ (7.6)

APCo

Fair Value of Derivative Instruments
December 31, 2015

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets - Nonaffiliated and Affiliated	$25.9	$ (10.3)	$ 15.6
Long-term Risk Management Assets - Nonaffiliated	0.3	(0.2)	0.1
Total Assets	26.2	(10.5)	15.7
Current Risk Management Liabilities - Nonaffiliated	18.1	(13.3)	4.8
Long-term Risk Management Liabilities - Nonaffiliated	0.3	(0.2)	0.1
Total Liabilities	18.4	(13.5)	4.9
Total MTM Derivative Contract Net Assets	$7.8	$ 3.0	$ 10.8

(a) Derivative instruments within this category are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts 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
September 30, 2016

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets - Nonaffiliated	$10.8	$ (5.6)	$ 5.2
Long-term Risk Management Assets - Nonaffiliated	0.6	(0.4)	0.2
Total Assets	11.4	(6.0)	5.4
Current Risk Management Liabilities - Nonaffiliated	7.2	(5.9)	1.3
Long-term Risk Management Liabilities - Nonaffiliated	0.6	(0.4)	0.2
Total Liabilities	7.8	(6.3)	1.5
Total MTM Derivative Contract Net Assets	$3.6	$ 0.3	$ 3.9

I&M

Fair Value of Derivative Instruments
December 31, 2015

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets - Nonaffiliated and Affiliated	$22.8	$ (10.5)	$ 12.3
Long-term Risk Management Assets - Nonaffiliated	0.6	(0.6)	—
Total Assets	23.4	(11.1)	12.3
Current Risk Management Liabilities - Nonaffiliated	17.0	(10.7)	6.3
Long-term Risk Management Liabilities - Nonaffiliated	2.6	(1.0)	1.6
Total Liabilities	19.6	(11.7)	7.9
Total MTM Derivative Contract Net Assets	$3.8	$ 0.6	$ 4.4

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

(b) Amounts 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.

166

OPCo

Fair Value of Derivative Instruments
September 30, 2016

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$0.1	$ (0.1)	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	0.1	(0.1)	—
Current Risk Management Liabilities	5.7	(0.1)	5.6
Long-term Risk Management Liabilities	103.5	—	103.5
Total Liabilities	109.2	(0.1)	109.1
Total MTM Derivative Contract Net Liabilities	$(109.1)	$ —	$ (109.1)

OPCo

Fair Value of Derivative Instruments
December 31, 2015

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$—	$ —	$ —
Long-term Risk Management Assets	19.2	—	19.2
Total Assets	19.2	—	19.2
Current Risk Management Liabilities	4.1	(0.5)	3.6
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	4.1	(0.5)	3.6
Total MTM Derivative Contract Net Assets	$15.1	$ 0.5	$ 15.6

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

(b) Amounts 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.

PSO

Fair Value of Derivative Instruments
September 30, 2016

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$1.2	$ (0.1)	$ 1.1
Long-term Risk Management Assets	—	—	—
Total Assets	1.2	(0.1)	1.1
Current Risk Management Liabilities	0.1	(0.1)	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.1	(0.1)	—
Total MTM Derivative Contract Net Assets	$1.1	$ —	$ 1.1

PSO

Fair Value of Derivative Instruments
December 31, 2015

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$0.6	$ —	$ 0.6
Long-term Risk Management Assets	—	—	—
Total Assets	0.6	—	0.6
Current Risk Management Liabilities	0.5	(0.3)	0.2
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.5	(0.3)	0.2
Total MTM Derivative Contract Net Assets	$0.1	$ 0.3	$ 0.4

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

(b) Amounts 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
September 30, 2016

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$1.5	$ (0.1)	$ 1.4
Long-term Risk Management Assets	—	—	—
Total Assets	1.5	(0.1)	1.4
Current Risk Management Liabilities	0.1	(0.1)	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.1	(0.1)	—
Total MTM Derivative Contract Net Assets	$1.4	$ —	$ 1.4

SWEPCo

Fair Value of Derivative Instruments
December 31, 2015

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$0.8	$ —	$ 0.8
Long-term Risk Management Assets	—	—	—
Total Assets	0.8	—	0.8
Current Risk Management Liabilities	3.4	(0.3)	3.1
Long-term Risk Management Liabilities	2.1	—	2.1
Total Liabilities	5.5	(0.3)	5.2
Total MTM Derivative Contract Net Assets (Liabilities)	$(4.7)	$ 0.3	$ (4.4)

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

(b) Amounts 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.

169

The tables below present the Registrants' activity of derivative risk management contracts for the three and nine months ended September 30, 2016 and 2015:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended September 30, 2016

Location of Gain (Loss)	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Vertically Integrated Utility Revenues	$2.4	$—	$—	$—	$—	$ —
Transmission and Distribution Utilities Revenues	0.1	—	—	—	—	—
Generation & Marketing Revenues	9.2	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	1.0	1.2	0.1	—	(0.1)
Purchased Electricity for Resale	1.5	0.8	0.1	—	—	—
Other Operation Expense	(0.4)	—	—	(0.1)	—	—
Maintenance Expense	(0.4)	(0.1)	—	(0.1)	(0.1)	(0.1)
Regulatory Assets (a)	(22.5)	5.2	1.6	(95.4)	0.1	2.8
Regulatory Liabilities (a)	28.6	16.9	5.5	—	0.8	3.7
Total Gain (Loss) on Risk Management Contracts	$18.5	$23.8	$8.4	$(95.5)	$0.8	$ 6.3

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended September 30, 2015

Location of Gain (Loss)	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Transmission and Distribution Utilities Revenues	$(0.9)	$—	$—	$—	$—	$ —
Generation & Marketing Revenues	1.0	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	(0.4)	0.4	(0.9)	—	—
Sales to AEP Affiliates	—	1.2	3.3	—	—	—
Purchased Electricity for Resale	1.6	0.8	—	—	—	—
Other Operation Expense	(0.7)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Maintenance Expense	(0.8)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)
Regulatory Assets (a)	0.1	0.9	(1.0)	—	(0.2)	0.2
Regulatory Liabilities (a)	(20.3)	3.2	(1.7)	(22.3)	(0.5)	1.1
Total Gain (Loss) on Risk Management Contracts	$(20.0)	$5.4	$0.8	$(23.4)	$(0.9)	$ 1.1

Amount of Gain (Loss) Recognized on Risk Management Contracts For the Nine Months Ended September 30, 2016						
Location of Gain (Loss)	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Vertically Integrated Utility Revenues	$3.1	$—	$—	$—	$—	$ —
Transmission and Distribution Utilities Revenues	0.1	—	—	—	—	—
Generation & Marketing Revenues	50.1	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	(0.8)	3.7	0.1	—	(0.1)
Sales to AEP Affiliates	—	2.1	5.8	—	—	—
Purchased Electricity for Resale	4.9	2.7	0.2	—	—	—
Other Operation Expense	(1.3)	(0.1)	(0.1)	(0.3)	(0.1)	(0.2)
Maintenance Expense	(1.6)	(0.3)	(0.1)	(0.3)	(0.2)	(0.2)
Regulatory Assets (a)	(51.0)	(7.2)	3.0	(115.9)	0.4	5.5
Regulatory Liabilities (a)	58.0	39.2	11.2	(15.2)	3.2	14.7
Total Gain (Loss) on Risk Management Contracts	$62.3	$35.6	$23.7	$(131.6)	$3.3	$ 19.7

Amount of Gain (Loss) Recognized on Risk Management Contracts For the Nine Months Ended September 30, 2015						
Location of Gain (Loss)	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Vertically Integrated Utilities Revenues	$6.7	$—	$—	$—	$—	$ —
Transmission and Distribution Utilities Revenues	(0.9)	—	—	—	—	—
Generation & Marketing Revenues	59.9	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	0.8	3.6	(0.9)	—	—
Sales to AEP Affiliates	—	1.5	4.3	—	—	—
Purchased Electricity for Resale	5.3	1.6	0.3	—	—	—
Other Operation Expense	(2.3)	(0.3)	(0.2)	(0.4)	(0.3)	(0.4)
Maintenance Expense	(2.2)	(0.5)	(0.2)	(0.4)	(0.2)	(0.3)
Regulatory Assets (a)	0.2	2.1	(1.2)	—	0.6	(1.2)
Regulatory Liabilities (a)	33.3	31.8	4.1	(24.8)	5.1	14.5
Total Gain (Loss) on Risk Management Contracts	$100.0	$37.0	$10.7	$(26.5)	$5.2	$ 12.6

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

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

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 statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the statements of income depending on the relevant facts and circumstances. Certain derivatives that

171

economically hedge future commodity risk are recorded in the same expense line item on the 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.

Accounting for Fair Value Hedging Strategies (Applies to AEP)

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.

AEP records realized and unrealized gains or losses on interest rate swaps that are designated and qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on the statements of operations. The following table shows the results of hedging gains (losses) during the three and nine months ended September 30, 2016 and 2015:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Gain (Loss) on Fair Value Hedging Instruments	$(1.1)	$3.7	$3.0	$6.8
Gain (Loss) on Fair Value Portion of Long-term Debt	1.1	(3.7)	(3.0)	(6.8)

During the three and nine months ended September 30, 2016 and 2015, 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 that is attributable to a particular risk), the Registrants initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects Net Income. The Registrants recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness would be recorded as a regulatory asset (for losses) or a regulatory liability (for gains) if applicable.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Total Revenues or Purchased Electricity for Resale on the statements of income or in Regulatory Assets or Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During the three and nine months ended September 30, 2016 and 2015, AEP applied cash flow hedging to outstanding power derivatives. During the three and nine months ended September 30, 2016 and 2015, the Registrant Subsidiaries did not apply cash flow hedging to outstanding power derivatives.

The Registrants reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During the three and nine months ended September 30, 2016 and 2015, AEP applied cash flow hedging to outstanding interest rate derivatives. During the three and nine months ended September 30, 2016 and 2015, the Registrant Subsidiaries did not apply cash flow hedging to outstanding interest rate derivatives.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Depreciation and Amortization expense on the statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three and nine months ended September 30, 2016 and 2015, the Registrants did not apply cash flow hedging to any outstanding foreign currency derivatives.

During the three and nine months ended September 30, 2016 and 2015, hedge ineffectiveness was immaterial or nonexistent for all of the hedge strategies disclosed above.

For details on effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets and the reasons for changes in cash flow hedges, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets as of September 30, 2016 and December 31, 2015 were:

Impact of Cash Flow Hedges on AEP’s Balance Sheets

	September 30, 2016		December 31, 2015	
	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency
	(in millions)			
Hedging Assets (a)	$6.5	$ —	$ 17.6	$ —
Hedging Liabilities (a)	48.4	0.2	26.1	0.4
AOCI Gain (Loss) Net of Tax	(27.1)	(16.1)	(5.2)	(17.2)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	0.9	(1.2)	(0.4)	(1.5)

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

As of September 30, 2016 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 135 months.

Impact of Cash Flow Hedges on the Registrant Subsidiaries’ Balance Sheets

September 30, 2016		December 31, 2015	
Interest Rate and Foreign Currency			
AOCI Gain (Loss)	Expected to be Reclassified to Net Income During the Next	AOCI Gain (Loss)	Expected to be Reclassified to Net Income During the Next

Company	Net of Tax	Twelve Months	Net of Tax	Twelve Months
	(in millions)			
APCo	$3.0	$ 0.7	$3.6	$ 0.7
I&M	(12.3)	(1.3)	(13.3)	(1.3)
OPCo	3.3	1.1	4.3	1.2
PSO	3.6	0.8	4.2	0.8
SWEPCo	(7.8)	(1.5)	(9.1)	(1.7)

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

Management limits credit risk in 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. Management 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.

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. A counterparty is required to post cash or letters of credit in the event 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, master agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Credit Downgrade Triggers (Applies to AEP, APCo, I&M, PSO and SWEPCo)

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, additional amounts of collateral are required if certain credit ratings decline below a specified rating threshold. 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. AEP, APCo, I&M, PSO and SWEPCo have not experienced a downgrade below a specified rating threshold that would require the posting of additional collateral. There is no exposure relating to derivative contracts, however, there is exposure relating to RTOs, ISOs and non-derivative contracts. The following table represents the exposure if credit ratings were to decline below a specified rating threshold as of September 30, 2016 and December 31, 2015:

	September 30, 2016			December 31, 2015		
Company	Amount of Collateral That Would Have Been Required to Post Attributable to RTOs and ISOs	Amount of Collateral Attributable to Other Contracts		Amount of Collateral That Would Have Been Required to Post Attributable to RTOs and ISOs	Amount of Collateral Attributable to Other Contracts	
	(in millions)					
AEP	$23.9	$ 292.4	(a)	$17.5	$ 297.8	(a)
APCo	4.4	—		4.9	0.1	
I&M	2.7	—		3.3	0.1	

PSO	3.9	3.2	—	3.2
SWEPCo	4.7	0.1	—	0.1

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

Cross-Default Triggers (Applies to AEP, APCo and I&M)

In addition, a majority of 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 that is $50 million or greater. 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 that the exposure has been reduced by cash collateral posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering contractual netting arrangements as of September 30, 2016 and December 31, 2015:

	September 30, 2016		
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 millions)		
AEP	$285.8	$ 10.6	$ 253.8
APCo	1.3	—	1.3
I&M	0.8	—	0.8

	December 31, 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 millions)		
AEP	$300.1	$ 0.8	$ 240.6
APCo	3.7	—	3.7
I&M	2.5	—	2.5

10. FAIR VALUE MEASUREMENTS

The disclosures in this note apply to all Registrants unless indicated otherwise.

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 established risk management policies as approved by the Finance Committee of AEP’s Board of Directors. AEPSC'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) 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 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 contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A portion of the Level 3 instruments have been economically hedged which limits potential earnings volatility.

AEP utilizes its trustee’s external pricing service to estimate 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, Cash and Cash Equivalents, Other Temporary Investments and Restricted Cash for Securitized Funding 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 equivalent funds. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

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 Registrants as of September 30, 2016 and December 31, 2015 are summarized in the following table:

Company	September 30, 2016 Book Value	September 30, 2016 Fair Value	December 31, 2015 Book Value	December 31, 2015 Fair Value
	(in millions)			
AEP	$19,839.5 (a)	$22,840.4	$19,572.7	$21,201.3
APCo	4,033.1	4,941.8	3,930.7	4,416.7
I&M	2,407.4	2,717.8	2,000.0	2,193.6
OPCo	1,763.4	2,213.4	2,157.7	2,472.7
PSO	1,286.2	1,502.6	1,286.1	1,402.9
SWEPCo	2,674.0	2,943.4	2,273.5	2,417.2

(a) Amounts include debt related to the Lawrenceburg Plant that has been classified as Liabilities Held for Sale on the balance sheet. See “Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)” section of Note 6 for additional information.

Fair Value Measurements of Other Temporary Investments (Applies to AEP)

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

The following is a summary of Other Temporary Investments:

Other Temporary Investments	September 30, 2016 Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash (a)	$159.2	$ —	$ —	$159.2
Fixed Income Securities – Mutual Funds (b)	92.3	0.3	—	92.6
Equity Securities – Mutual Funds	14.2	13.2	—	27.4
Total Other Temporary Investments	$265.7	$ 13.5	$ —	$279.2

Other Temporary Investments	December 31, 2015 Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash (a)	$271.0	$ —	$ —	$271.0
Fixed Income Securities – Mutual Funds (b)	91.1	—	(0.7)	90.4
Equity Securities – Mutual Funds	13.7	11.7	—	25.4
Total Other Temporary Investments	$375.8	$ 11.7	$ (0.7)	$386.8

(a) Primarily represents amounts held for the repayment of debt.
(b) Primarily short and intermediate maturities which may be sold and do not contain maturity dates.

The following table provides the activity for fixed income and equity securities within Other Temporary Investments for the three and nine months ended September 30, 2016 and 2015:

	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
	(in millions)			
Proceeds from Investment Sales	$ —	$ —	$ —	$ —
Purchases of Investments	0.6	9.5	1.6	10.3
Gross Realized Gains on Investment Sales	—	—	—	—
Gross Realized Losses on Investment Sales	—	—	—	—

For details of the reasons for changes in Securities Available for Sale included in Accumulated Other Comprehensive Income (Loss) for the three and nine months ended September 30, 2016 and 2015, see Note 3.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal (Applies to AEP and I&M)

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, I&M or their affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

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

I&M records securities held in these trust funds in Spent Nuclear Fuel and Decommissioning Trusts on its balance sheets. I&M records these securities 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 debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the debt and equity investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. 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 following is a summary of nuclear trust fund investments as of September 30, 2016 and December 31, 2015:

	September 30, 2016			December 31, 2015		
	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$35.2	$ —	$ —	$168.3	$ —	$ —
Fixed Income Securities:						
United States Government	892.7	55.5	(2.1)	731.1	35.9	(2.6)
Corporate Debt	66.5	6.1	(1.0)	57.9	3.2	(1.1)
State and Local Government	16.4	1.2	(0.3)	22.2	1.1	(0.3)
Subtotal Fixed Income Securities	975.6	62.8	(3.4)	811.2	40.2	(4.0)
Equity Securities - Domestic	1,220.0	631.6	(78.0)	1,126.9	571.6	(79.3)
Spent Nuclear Fuel and Decommissioning Trusts	$2,230.8	$ 694.4	$ (81.4)	$2,106.4	$ 611.8	$ (83.3)

The following table provides the securities activity within the decommissioning and SNF trusts for the three and nine months ended September 30, 2016 and 2015:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Proceeds from Investment Sales	$650.0	$921.5	$2,427.0	$1,437.3
Purchases of Investments	656.5	938.4	2,452.9	1,479.1
Gross Realized Gains on Investment Sales	13.9	15.0	41.9	33.8
Gross Realized Losses on Investment Sales	6.5	13.1	22.2	22.8

The base cost of fixed income securities was $913 million and $771 million as of September 30, 2016 and December 31, 2015, respectively. The base cost of equity securities was $588 million and $555 million as of September 30, 2016 and December 31, 2015, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of September 30, 2016 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 330.4
1 year – 5 years	317.3
5 years – 10 years	150.4
After 10 years	177.5
Total	$ 975.6

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, the Registrants' financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2016 and December 31, 2015. 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.

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Cash and Cash Equivalents (a)	$12.8	$5.3	$—	$194.1	$212.2
Other Temporary Investments					
Restricted Cash (a)	146.7	5.7	—	6.8	159.2
Fixed Income Securities – Mutual Funds	92.6	—	—	—	92.6
Equity Securities – Mutual Funds (b)	27.4	—	—	—	27.4
Total Other Temporary Investments	266.7	5.7	—	6.8	279.2
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	5.3	399.3	214.7	(203.7)	415.6
Cash Flow Hedges:					
Commodity Hedges (c)	—	10.5	1.1	(5.0)	6.6
Fair Value Hedges	—	—	—	0.3	0.3
Total Risk Management Assets	5.3	409.8	215.8	(208.4)	422.5
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	18.7	—	—	16.5	35.2
Fixed Income Securities:					
United States Government	—	892.7	—	—	892.7
Corporate Debt	—	66.5	—	—	66.5
State and Local Government	—	16.4	—	—	16.4
Subtotal Fixed Income Securities	—	975.6	—	—	975.6
Equity Securities – Domestic (b)	1,220.0	—	—	—	1,220.0
Total Spent Nuclear Fuel and Decommissioning Trusts	1,238.7	975.6	—	16.5	2,230.8
Total Assets	$1,523.5	$1,396.4	$215.8	$9.0	$3,144.7
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$10.0	$394.2	$98.7	$(232.6)	$270.3

Cash Flow Hedges:					
Commodity Hedges (c)	—	34.8	18.7	(5.0)	48.5
Interest Rate/Foreign Currency Hedges	—	0.2	—	—	0.2
Fair Value Hedges	—	—	—	0.3	0.3
Total Risk Management Liabilities	$10.0	$429.2	$117.4	$(237.3)	$319.3

180

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Cash and Cash Equivalents (a)	$3.9	$4.3	$—	$168.2	$176.4
Other Temporary Investments					
Restricted Cash (a)	230.0	7.7	—	33.3	271.0
Fixed Income Securities – Mutual Funds	90.4	—	—	—	90.4
Equity Securities – Mutual Funds (b)	25.4	—	—	—	25.4
Total Other Temporary Investments	345.8	7.7	—	33.3	386.8
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	11.5	495.0	219.7	(287.7)	438.5
Cash Flow Hedges:					
Commodity Hedges (c)	—	15.9	1.0	0.7	17.6
Fair Value Hedges	—	—	—	0.1	0.1
Total Risk Management Assets	11.5	510.9	220.7	(286.9)	456.2
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	160.5	—	—	7.8	168.3
Fixed Income Securities:					
United States Government	—	731.1	—	—	731.1
Corporate Debt	—	57.9	—	—	57.9
State and Local Government	—	22.2	—	—	22.2
Subtotal Fixed Income Securities	—	811.2	—	—	811.2
Equity Securities – Domestic (b)	1,126.9	—	—	—	1,126.9
Total Spent Nuclear Fuel and Decommissioning Trusts	1,287.4	811.2	—	7.8	2,106.4
Total Assets	$1,648.6	$1,334.1	$220.7	$(77.6)	$3,125.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$24.1	$471.5	$67.3	$(326.3)	$236.6
Cash Flow Hedges:					
Commodity Hedges (c)	—	18.9	6.5	0.7	26.1
Interest Rate/Foreign Currency Hedges	—	0.4	—	—	0.4
Fair Value Hedges	—	3.0	—	0.1	3.1
Total Risk Management Liabilities	$24.1	$493.8	$73.8	$(325.5)	$266.2

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Restricted Cash for Securitized Funding (a)	$7.8	$—	$—	$0.1	$7.9
Risk Management Assets - Nonaffiliated					
Risk Management Commodity Contracts (c) (g)	—	8.3	2.8	(7.7)	3.4
Total Assets	$7.8	$8.3	$2.8	$(7.6)	$11.3
Liabilities:					
Risk Management Liabilities - Nonaffiliated					
Risk Management Commodity Contracts (c) (g)	$—	$8.8	$9.9	$(7.7)	$11.0

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Restricted Cash for Securitized Funding (a)	$14.8	$—	$—	$0.1	$14.9
Risk Management Assets - Nonaffiliated and Affiliated					
Risk Management Commodity Contracts (c) (g)	0.2	13.9	12.2	(10.6)	15.7
Total Assets	$15.0	$13.9	$12.2	$(10.5)	$30.6
Liabilities:					
Risk Management Liabilities - Nonaffiliated					
Risk Management Commodity Contracts (c) (g)	$0.2	$17.8	$0.5	$(13.6)	$4.9

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets - Nonaffiliated					
Risk Management Commodity Contracts (c) (g)	$—	$6.6	$4.7	$(5.9)	$5.4
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	18.7	—	—	16.5	35.2
Fixed Income Securities:					
United States Government	—	892.7	—	—	892.7
Corporate Debt	—	66.5	—	—	66.5
State and Local Government	—	16.4	—	—	16.4
Subtotal Fixed Income Securities	—	975.6	—	—	975.6
Equity Securities - Domestic (b)	1,220.0	—	—	—	1,220.0
Total Spent Nuclear Fuel and Decommissioning Trusts	1,238.7	975.6	—	16.5	2,230.8
Total Assets	$1,238.7	$982.2	$4.7	$10.6	$2,236.2
Liabilities:					
Risk Management Liabilities - Nonaffiliated					
Risk Management Commodity Contracts (c) (g)	$—	$7.5	$0.2	$(6.2)	$1.5

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets - Nonaffiliated and Affiliated					
Risk Management Commodity Contracts (c) (g)	$0.1	$17.0	$6.3	$(11.1)	$12.3
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	160.5	—	—	7.8	168.3
Fixed Income Securities:					
United States Government	—	731.1	—	—	731.1
Corporate Debt	—	57.9	—	—	57.9
State and Local Government	—	22.2	—	—	22.2
Subtotal Fixed Income Securities	—	811.2	—	—	811.2
Equity Securities - Domestic (b)	1,126.9	—	—	—	1,126.9
Total Spent Nuclear Fuel and Decommissioning Trusts	1,287.4	811.2	—	7.8	2,106.4

Total Assets	$1,287.5	$828.2	$6.3	$(3.3)	$2,118.7
Liabilities:					
Risk Management Liabilities - Nonaffiliated					
Risk Management Commodity Contracts (c) (g)	$0.1	$17.5	$2.0	$(11.7)	$7.9

183

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2016

Assets:	Level 1	Level 2	Level 3	Other	Total
	(in millions)				
Restricted Cash for Securitized Funding (a)	$16.1	$—	$—	$0.1	$16.2
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	0.1	—	(0.1)	—
Total Assets	$16.1	$0.1	$—	$—	$16.2
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$0.1	$109.1	$(0.1)	$109.1

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

Assets:	Level 1	Level 2	Level 3	Other	Total
	(in millions)				
Restricted Cash for Securitized Funding (a)	$—	$—	$—	$27.7	$27.7
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	—	16.0	3.2	19.2
Total Assets	$—	$—	$16.0	$30.9	$46.9
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$0.8	$0.1	$2.7	$3.6

184

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.1	$ 1.2	$ (0.2)	$ 1.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.1	$ 0.1	$ (0.2)	$ —

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 0.7	$ (0.1)	$ 0.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.5	$ 0.1	$ (0.4)	$ 0.2

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Cash and Cash Equivalents (a)	$12.8	$—	$—	$2.4	$15.2
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	0.1	1.4	(0.1)	1.4
Total Assets	$12.8	$0.1	$1.4	$2.3	$16.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$—	$0.1	$(0.1)	$—

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Cash and Cash Equivalents (a)	$3.6	$—	$—	$1.6	$5.2
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	—	0.9	(0.1)	0.8
Total Assets	$3.6	$—	$0.9	$1.5	$6.0
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$5.5	$0.1	$(0.4)	$5.2

(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 September 30, 2016 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 periods 2017-2019; Level 2 matures $1 million in 2016, $5 million in periods 2017-2019 and $(1) million in periods 2022-2032; Level 3 matures $4 million in 2016, $36 million in periods 2017-2019, $22 million in periods 2020-2021 and $54 million in periods 2022-2032. 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, 2015 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $(9) million in 2016 and $(4) million in periods 2017-2019; Level 2 matures $2 million in 2016, $18 million in periods 2017-2019 and $4 million in periods 2020-2021; Level 3 matures $28 million in 2016, $29 million in periods 2017-2019, $19 million in periods 2020-2021 and $76 million in periods 2022-2032. Risk management commodity contracts are substantially comprised of power contracts.

(g) Substantially comprised of power contracts for the Registrant Subsidiaries.

There were no transfers between Level 1 and Level 2 during the three and nine months ended September 30, 2016 and 2015.

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:

Three Months Ended September 30, 2016	AEP	APCo (a)	I&M (a)	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of June 30, 2016	$149.3	$(12.9)	$3.5	$(14.6)	$1.1	$ 1.4
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	34.2	22.7	3.8	(0.1)	0.4	4.0
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b)	12.3	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(34.4)	—	—	—	—	—
Purchases, Issuances and Settlements (d)	(37.1)	(17.9)	(5.0)	0.9	(0.7)	(4.4)
Transfers into Level 3 (e) (f)	13.1	0.1	—	—	—	—
Transfers out of Level 3 (f) (g)	(10.0)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (h)	(29.0)	0.9	2.2	(95.3)	0.3	0.3
Balance as of September 30, 2016	$98.4	$(7.1)	$4.5	$(109.1)	$1.1	$ 1.3

Three Months Ended September 30, 2015	AEP	APCo (a)	I&M (a)	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of June 30, 2015	$203.1	$33.8	$11.8	$37.7	$1.7	$ 2.0
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	11.1	5.1	0.9	—	(0.3)	2.4
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b)	6.2	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(2.1)	—	—	—	—	—
Purchases, Issuances and Settlements (d)	(28.9)	(14.0)	(3.6)	0.3	(0.2)	(2.9)
Transfers into Level 3 (e) (f)	7.8	—	—	—	—	—
Transfers out of Level 3 (f) (g)	(5.4)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (h)	(25.0)	(1.8)	(2.7)	(22.3)	(0.2)	(0.2)
Balance as of September 30, 2015	$166.8	$23.1	$6.4	$15.7	$1.0	$ 1.3

Nine Months Ended September 30, 2016	AEP	APCo (a)	I&M (a)	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of December 31, 2015	$146.9	$11.7	$4.3	$15.9	$0.6	$ 0.8
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	42.1	25.5	7.0	(1.8)	(1.0)	7.7
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b)	45.5	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(16.7)	—	—	—	—	—
Purchases, Issuances and Settlements (d)	(67.1)	(36.2)	(10.3)	4.0	0.4	(8.4)
Transfers into Level 3 (e) (f)	11.2	—	—	—	—	—
Transfers out of Level 3 (f) (g)	1.1	0.1	0.1	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (h)	(64.6)	(8.2)	3.4	(127.2)	1.1	1.2
Balance as of September 30, 2016	$98.4	$(7.1)	$4.5	$(109.1)	$1.1	$ 1.3

Nine Months Ended September 30, 2015	AEP	APCo (a)	I&M (a)	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of December 31, 2014	$150.8	$15.8	$14.7	$48.4	$(0.3)	$ (0.5)
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	13.6	1.7	(0.2)	1.2	(0.2)	9.2
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b)	54.3	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(3.8)	—	—	—	—	—
Purchases, Issuances and Settlements (d)	(60.2)	(16.1)	(12.8)	(7.9)	0.5	(8.7)
Transfers into Level 3 (e) (f)	28.3	—	—	—	—	—
Transfers out of Level 3 (f) (g)	(17.1)	1.2	0.8	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (h)	0.9	20.5	3.9	(26.0)	1.0	1.3
Balance as of September 30, 2015	$166.8	$23.1	$6.4	$15.7	$1.0	$ 1.3

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

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of September 30, 2016 and December 31, 2015:

Significant Unobservable Inputs
September 30, 2016
AEP

	Fair Value		Valuation	Significant Unobservable	Input/Range		Weighted
	Assets	Liabilities	Technique	Input	Low	High	Average
	(in millions)						
Energy Contracts	$207.5	$ 103.7	Discounted Cash Flow	Forward Market Price (a)	$10.19	$143.84	$ 43.20
				Counterparty Credit Risk (b)	40	840	424
FTRs	8.3	13.7	Discounted Cash Flow	Forward Market Price (a)	$(9.89)	$10.63	$ 0.73
Total	$215.8	$ 117.4					

Significant Unobservable Inputs
December 31, 2015
AEP

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$212.3	$ 70.3	Discounted Cash Flow	Forward Market Price (a)	$9.69	$165.36	$ 36.35
				Counterparty Credit Risk (c)	670		
FTRs	8.4	3.5	Discounted Cash Flow	Forward Market Price (a)	$(6.99)	$10.34	$ 1.10
Total	$220.7	$ 73.8					

Significant Unobservable Inputs
September 30, 2016
APCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$2.1	$ 0.2	Discounted Cash Flow	Forward Market Price	$16.51	$47.42	$ 34.85
FTRs	0.7	9.7	Discounted Cash Flow	Forward Market Price	(0.99)	10.63	1.94
Total	$2.8	$ 9.9					

Significant Unobservable Inputs
December 31, 2015
APCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$7.9	$ 0.2	Discounted Cash Flow	Forward Market Price	$12.61	$47.24	$ 32.38
FTRs	4.3	0.3	Discounted Cash Flow	Forward Market Price	(6.96)	8.43	1.34
Total	$12.2	$ 0.5					

Significant Unobservable Inputs
September 30, 2016
I&M

	Fair Value		Valuation	Significant	Input/Range		
				Unobservable			Weighted
	Assets	Liabilities	Technique	Input (a)	Low	High	Average
	(in millions)						
Energy Contracts	$1.6	$ 0.2	Discounted Cash Flow	Forward Market Price	$16.51	$47.42	$ 34.85
FTRs	3.1	—	Discounted Cash Flow	Forward Market Price	(9.89)	10.63	1.10
Total	$4.7	$ 0.2					

Significant Unobservable Inputs
December 31, 2015
I&M

	Fair Value		Valuation	Significant	Input/Range		
				Unobservable			Weighted
	Assets	Liabilities	Technique	Input (a)	Low	High	Average
	(in millions)						
Energy Contracts	$6.0	$ 0.2	Discounted Cash Flow	Forward Market Price	$12.61	$47.24	$ 32.38
FTRs	0.3	1.8	Discounted Cash Flow	Forward Market Price	(6.96)	8.43	1.34
Total	$6.3	$ 2.0					

Significant Unobservable Inputs
September 30, 2016
OPCo

	Fair Value		Valuation	Significant	Input/Range		
				Unobservable			Weighted
	Assets	Liabilities	Technique	Input	Low	High	Average
	(in millions)						
Energy Contracts	$—	$ 109.1	Discounted Cash Flow	Forward Market Price (a)	$24.38	$78.45	$ 52.45
				Counterparty Credit Risk (b)	40	323	246
Total	$—	$ 109.1					

Significant Unobservable Inputs
December 31, 2015
OPCo

	Fair Value		Valuation	Significant	Input/Range		
				Unobservable			Weighted
	Assets	Liabilities	Technique	Input (a)	Low	High	Average
	(in millions)						
Energy Contracts	$16.0	$ 0.1	Discounted Cash Flow	Forward Market Price	$41.61	$165.36	$ 86.84

Significant Unobservable Inputs
September 30, 2016
PSO

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$1.2	$ 0.1	Discounted Cash Flow	Forward Market Price	$(8.33)	$1.02	$ (0.39)

Significant Unobservable Inputs
December 31, 2015
PSO

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$0.7	$ 0.1	Discounted Cash Flow	Forward Market Price	$(6.96)	$8.43	$ 1.34

Significant Unobservable Inputs
September 30, 2016
SWEPCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$1.4	$ 0.1	Discounted Cash Flow	Forward Market Price	$(8.33)	$1.02	$ (0.39)

Significant Unobservable Inputs
December 31, 2015
SWEPCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$0.9	$ 0.1	Discounted Cash Flow	Forward Market Price	$(6.96)	$8.43	$ 1.34

(a) Represents market prices in dollars per MWh.
(b) Represents prices of credit default swaps used to calculate counterparty credit risk, reported in basis points.
(c) 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 for the Registrants as of September 30, 2016 and December 31, 2015:

Sensitivity of Fair Value Measurements

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)

11. INCOME TAXES

The disclosures in this note apply to all Registrants unless indicated otherwise.

AEP System Tax Allocation Agreement

AEP and subsidiaries join in the filing of 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 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.

Valuation Allowance (Applies to AEP)

AEP assesses available positive and negative evidence to estimate whether sufficient future taxable income of the appropriate tax character will be generated to realize the benefits of existing deferred tax assets. When the evaluation of the evidence indicates that AEP will not be able to realize the benefits of existing deferred tax assets, a valuation allowance is recorded to reduce existing deferred tax assets to the net realizable amount. Objective negative evidence evaluated includes whether AEP has a history of recognizing income of the character which can be offset by capital loss carryforwards. Other objective negative evidence evaluated is the impact recently enacted federal tax legislation will have on future taxable income and on AEP's ability to benefit from the carryforward of charitable contribution deductions.

On the basis of this evaluation, AEP recorded a change in the valuation allowance in the third quarter of 2016. AEP reduced the capital loss valuation allowance by $66 million to reflect the impact of the reclassification of certain assets as held for sale and the filing of the 2015 federal income tax return. The sale of these assets is expected to result in a gain, the character of which allows AEP to use the capital loss and reverse substantially all of the remaining capital loss valuation allowance previously recorded.

A valuation allowance of $9 million has been recorded against AEP's deferred tax asset balance as of September 30, 2016. The valuation allowance reflects management's assessment of the amount of deferred tax assets that are more likely than not to be realized. The amount of the deferred tax assets realizable, however, could be adjusted if estimates of future taxable income are materially impacted during the carryforward period.

Federal and State Income Tax Audit Status

AEP and 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. AEP and subsidiaries received a Revenue Agents Report in April 2016, completing the 2011 through 2013 audit cycle indicating an agreed upon audit. The 2011 through 2013 audit was submitted to the Congressional Joint Committee on Taxation for approval. AEP was informed that the IRS expects the Joint Committee to refer the audit back to the IRS exam team for further consideration. Although the outcome of tax audits are uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, the Registrants 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 net income.

AEP and subsidiaries file income tax returns in various state, local or foreign jurisdictions. These taxing authorities routinely examine the tax returns. AEP and 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 net income. The Registrants are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2009.

State Tax Legislation (Applies to AEP, PSO and SWEPCo)

In March 2016, the Texas Comptroller of Public Accounts issued clarifying guidance regarding the treatment of transmission and distribution expenses included in the computation of taxable income for purposes of calculating the Texas gross margin tax. The guidance clarified which specific transmission and distribution expenses are included in the computation of the cost of goods sold deduction. This guidance resulted in a net favorable adjustment to net income of $21 million, $2 million and $9 million during the first nine months of 2016 for AEP, PSO and SWEPCo, respectively.

In March 2016, Louisiana enacted several tax bills impacting income taxes, franchise taxes and sales taxes. The income tax provisions limit the use of Louisiana net operating losses and the sales tax provisions increase the sales tax rate and suspend or eliminate certain exemptions. The legislation is not expected to materially impact net income or cash flows.

12. FINANCING ACTIVITIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

Long-term Debt Outstanding (Applies to AEP)

The following table details long-term debt outstanding as of September 30, 2016 and December 31, 2015:

Type of Debt	September 30, 2016		December 31, 2015
	(in millions)		
Senior Unsecured Notes	$ 14,073.9	(a)	$ 13,629.1
Pollution Control Bonds	1,724.5		1,784.8
Notes Payable	268.5		264.7
Securitization Bonds	1,737.6		2,024.0
Spent Nuclear Fuel Obligation (b)	266.1		265.6
Other Long-term Debt	1,768.9		1,604.5
Total Long-term Debt Outstanding	19,839.5	(a)	19,572.7
Long-term Debt Due Within One Year	2,519.6	(a)	1,831.8
Long-term Debt	$ 17,319.9		$ 17,740.9

(a) Amounts include debt related to the Lawrenceburg Plant that has been classified as Liabilities Held for Sale on the balance sheet. See “Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)” section of Note 6 for additional information.

(b) 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 September 30, 2016 and December 31, 2015, respectively, and are included in Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets.

Long-term Debt Activity

Long-term debt and other securities issued, retired and principal payments made during the first nine months of 2016 are shown in the tables below:

Company	Type of Debt	Principal Amount (a)	Interest Rate	Due Date
Issuances:		(in millions)	(%)	
APCo	Other Long-term Debt	$ 125.0	Variable	2019
APCo	Pollution Control Bonds	125.3	Variable	2016
APCo	Pollution Control Bonds	65.4	1.70	2020
I&M	Notes Payable	87.9	Variable	2020
I&M	Senior Unsecured Notes	400.0	4.55	2046
PSO	Senior Unsecured Notes	50.0	3.05	2026
PSO	Senior Unsecured Notes	100.0	4.11	2046
SWEPCo	Other Long-term Debt	5.2	3.50	2023
SWEPCo	Senior Unsecured Notes	400.0	2.75	2026
Non-Registrant:				
TCC	Other Long-term Debt	125.0	Variable	2019
TNC	Other Long-term Debt	75.0	Variable	2019
Transource Missouri	Other Long-term Debt	11.5	Variable	2018
Total Issuances		$ 1,570.3		

(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.

196

Company	Type of Debt	Principal Amount Paid	Interest Rate	Due Date
Retirements and Principal Payments:		(in millions)	(%)	
APCo	Pollution Control Bonds	$ 125.3	Variable	2016
APCo	Pollution Control Bonds	65.3	2.25	2016
APCo	Securitization Bonds	23.0	2.008	2024
I&M	Notes Payable	0.8	Variable	2016
I&M	Notes Payable	0.5	2.12	2016
I&M	Notes Payable	12.6	Variable	2017
I&M	Notes Payable	24.8	Variable	2019
I&M	Notes Payable	31.0	Variable	2019
I&M	Notes Payable	6.1	Variable	2020
I&M	Other Long-term Debt	1.0	6.00	2025
OPCo	Other Long-term Debt	0.1	1.149	2028
OPCo	Securitization Bonds	45.8	0.958	2018
OPCo	Senior Unsecured Notes	350.0	6.00	2016
PSO	Other Long-term Debt	0.3	3.00	2027
PSO	Senior Unsecured Notes	150.0	6.15	2016
SWEPCo	Notes Payable	3.3	4.58	2032
Non-Registrant:				
AEGCo	Senior Unsecured Notes	7.3	6.33	2037
AEP Subsidiaries	Notes Payable	5.1	Variable	2017
AEP Subsidiaries	Notes Payable	0.1	5.75	2021
AGR	Pollution Control Bonds	60.0	Variable	2016
TCC	Other Long-term Debt	100.0	Variable	2016
TCC	Securitization Bonds	44.2	6.25	2016
TCC	Securitization Bonds	149.1	5.17	2018
TCC	Securitization Bonds	26.9	0.88	2017
TNC	Other Long-term Debt	75.0	Variable	2016
Total Retirements and Principal Payments		$ 1,307.6		

In October 2016, I&M retired $16 million of Notes Payable related to DCC Fuel.

As of September 30, 2016, trustees held, on behalf of AEP, $614 million of their reacquired Pollution Control Bonds. Of this total, $40 million and $345 million related to I&M and OPCo, respectively.

Dividend Restrictions

Parent Restrictions (Applies to AEP)

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

Pursuant to the leverage restrictions in credit agreements, AEP 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. As of September 30, 2016, none of AEP’s retained earnings were restricted for the purpose of the payment of dividends.

Utility Subsidiaries' Restrictions

AEP utility 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 subsidiaries to transfer funds to Parent in the form of dividends.

Certain AEP 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." Additionally, the Federal Power Act creates a reserve on earnings attributable to hydroelectric generation plants. Because of their ownership of such plants, this reserve applies to AGR, APCo and I&M. As of September 30, 2016, these restrictions did not limit the ability of the subsidiaries to pay dividends out of retained earnings.

Corporate Borrowing Program - AEP System (Applies to Registrant Subsidiaries)

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, and a Nonutility Money Pool, which funds certain AEP nonutility 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 September 30, 2016 and December 31, 2015 are included in Advances to Affiliates and Advances from Affiliates, respectively, on each of the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and their corresponding authorized borrowing limits for the nine months ended September 30, 2016 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 September 30, 2016	Authorized Short-term Borrowing Limit
	(in millions)					
APCo	$286.9	$ 25.7	$ 165.5	$ 24.9	$ (59.7)	$ 600.0
I&M	369.1	97.6	118.9	21.8	(13.9)	500.0
OPCo	227.9	379.2	137.8	251.1	0.2	400.0
PSO	9.6	205.4	5.1	47.0	51.1	300.0
SWEPCo	249.4	308.2	171.8	302.8	297.4	350.0

The activity in the above table does not include short-term lending activity of SWEPCo's wholly-owned subsidiary, Mutual Energy SWEPCo, LLC, which is a participant in the Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of September 30, 2016 and December 31, 2015 are included in Advances to Affiliates on SWEPCo's balance sheets. For the nine months ended September 30, 2016, Mutual Energy SWEPCo, LLC had the following activity in the Nonutility Money Pool:

Maximum Loans	Average Loans	Loans

to the Nonutility Money Pool	to the Nonutility Money Pool	to the Nonutility Money Pool as of September 30, 2016
(in millions)		
$2.0	$ 2.0	$ 2.0

198

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

	Nine Months Ended September 30,	
	2016	2015
Maximum Interest Rate	0.91 %	0.59 %
Minimum Interest Rate	0.69 %	0.39 %

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the nine months ended September 30, 2016 and 2015 are summarized for all Registrant Subsidiaries in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Nine Months Ended September 30,		Average Interest Rate for Funds Loaned to the Utility Money Pool for Nine Months Ended September 30,	
Company	2016	2015	2016	2015
APCo	0.78 %	0.46 %	0.79 %	0.46 %
I&M	0.73 %	0.47 %	0.78 %	0.46 %
OPCo	0.85 %	— %	0.74 %	0.47 %
PSO	0.76 %	0.49 %	0.81 %	0.46 %
SWEPCo	0.79 %	0.46 %	0.91 %	0.48 %

Maximum, minimum and average interest rates for funds loaned to the Nonutility Money Pool for the nine months ended September 30, 2016 are summarized for Mutual Energy SWEPCo, LLC in the following table:

Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool
0.91 %	0.69 %	0.79 %

Short-term Debt (Applies to AEP)

Outstanding short-term debt was as follows:

	September 30, 2016		December 31, 2015
Type of Debt	Outstanding	Interest	

	Amount	Rate (a)	Outstanding Amount	Interest Rate (a)
	(in millions)		(in millions)	
Securitized Debt for Receivables (b)	$750.0	0.65 %	$675.0	0.30 %
Commercial Paper	728.3	0.90 %	125.0	0.81 %
Total Short-term Debt	$1,478.3		$800.0	

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

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 5.

Sale of Receivables – AEP Credit (Applies to AEP)

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. These securitized transactions allow AEP Credit to repay its outstanding debt obligations, continue to purchase the operating companies' receivables and accelerate AEP Credit's cash collections.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and expires in June 2018.

Accounts receivable information for AEP Credit is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(dollars in millions)			
Effective Interest Rates on Securitization of Accounts Receivable	0.73 %	0.30 %	0.65 %	0.28 %
Net Uncollectible Accounts Receivable Written Off	$7.7	$13.5	$17.5	$27.5

	September 30, 2016	December 31, 2015
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$1,037.7	$ 924.8
Total Principal Outstanding	750.0	675.0
Delinquent Securitized Accounts Receivable	47.7	48.3
Bad Debt Reserves Related to Securitization of Accounts Receivable	27.8	17.5
Unbilled Receivables Related to Securitization of Accounts Receivable	297.1	357.8

AEP Credit's delinquent customer accounts receivable represent accounts greater than 30 days past due.

Sale of Receivables – AEP Credit (Applies to Registrant Subsidiaries)

Under this 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' statements of income. The Registrant Subsidiaries manage and service their customer accounts receivable, which are sold to AEP Credit. AEP Credit securitizes the eligible receivables for the operating companies and retains the remainder.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement for each Registrant Subsidiary as of September 30, 2016 and December 31, 2015 was as follows:

Company	September 30, 2016	December 31, 2015
	(in millions)	
APCo	$131.9	$ 135.4
I&M	152.5	134.8
OPCo	407.1	351.4
PSO	146.1	116.1

SWEPCo	170.0	151.8

200

The fees paid by the Registrant Subsidiaries to AEP Credit for customer accounts receivable sold were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2016	2015	2016	2015
	(in millions)			
APCo	$1.6	$2.0	$5.4	$6.0
I&M	2.0	2.2	5.6	6.6
OPCo	8.1	8.5	23.4	23.2
PSO	1.8	1.7	4.7	4.5
SWEPCo	2.1	2.0	5.3	5.3

The Registrant Subsidiaries' proceeds on the sale of receivables to AEP Credit were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2016	2015	2016	2015
	(in millions)			
APCo	$361.7	$355.3	$1,071.6	$1,115.5
I&M	448.0	401.5	1,220.2	1,192.1
OPCo	750.9	670.7	2,011.2	1,949.0
PSO	390.6	411.5	971.9	1,025.9
SWEPCo	460.4	468.0	1,183.9	1,222.3

13. VARIABLE INTEREST ENTITIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

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 AEP is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of the VIE's variability AEP 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.

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

Consolidated Variable Interests Entities

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 September 30, 2016 and 2015 were $42 million and $41 million, respectively, and for the nine months ended September 30, 2016 and 2015 were $127 million and $124 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on SWEPCo's 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 September 30, 2016 and 2015 were $23 million and $29 million, respectively, and for the nine months ended September 30, 2016 and 2015 were $77 million and $86 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 tables below for the classification of DCC Fuel's assets and liabilities on I&M's balance sheets.

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 $1.3 billion and $1.5 billion as of September 30, 2016 and December 31, 2015, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the balance sheets. Transition

Funding has securitized transition assets of $1.1 billion and $1.3 billion as of September 30, 2016 and December 31, 2015, respectively, which are presented separately on the face of the balance sheets. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from TCC under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to TCC or any other AEP entity. TCC acts as the servicer for Transition Funding's securitized transition assets and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Transition Funding's assets and liabilities on the balance sheets.

Ohio Phase-in-Recovery Funding was formed for the sole purpose of issuing and servicing securitization bonds related to phase-in recovery property. Management has concluded that OPCo is the primary beneficiary of Ohio Phase-in-Recovery Funding because OPCo has the power to direct the most significant activities of the VIE and OPCo's equity interest could potentially be significant. Therefore, OPCo is required to consolidate Ohio Phase-in-Recovery Funding. The securitized bonds totaled $140 million and $185 million as of September 30, 2016 and December 31, 2015, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the balance sheets. Ohio Phase-in-Recovery Funding has securitized assets of $68 million and $86 million as of September 30, 2016 and December 31, 2015, respectively, which are presented separately on the face of the 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 tables below for the classification of Ohio Phase-in-Recovery Funding's assets and liabilities on OPCo's 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 $319 million and $342 million as of September 30, 2016 and December 31, 2015, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the balance sheets. Appalachian Consumer Rate Relief Funding has securitized assets of $311 million and $328 million as of September 30, 2016 and December 31, 2015, respectively, which are presented separately on the face of the 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 tables below for the classification of Appalachian Consumer Rate Relief Funding's assets and liabilities on APCo's balance sheets.

AEP Credit is a wholly-owned subsidiary of Parent. 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 AEP's control of

AEP Credit, management concluded that AEP is the primary beneficiary and is required to consolidate AEP Credit. See the tables below for the classification of AEP Credit's assets and liabilities on the balance sheets. See "Sale of Receivables - AEP Credit" section of Note 12.

AEP's 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. AEP's subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on AEP's control and the structure of the protected cell of EIS, management concluded that AEP is the primary beneficiary of the protected cell and is required to consolidate the protected cell of EIS. The insurance premium expense to the protected cell for the three months ended September 30, 2016 and 2015 was $15 million and $13 million, respectively, and for the nine months ended September 30, 2016 and 2015 was $28 million and $27 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on the 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 and AEP's equity interest could potentially be significant. Therefore, AEP is required to consolidate Transource Energy. In January 2014, Transource Missouri (a wholly-owned subsidiary of Transource Energy) acquired transmission assets from the non-controlling owner and issued debt and received a capital contribution to fund the acquisition. The majority of Transource Energy's activity resulted from the asset acquisition, construction projects, debt issuance and capital contribution. AEP has provided capital contributions to Transource Energy of $38 million and $47 million during the nine months ended September 30, 2016 and the year ended December 31, 2015, 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 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
September 30, 2016

	Registrant Subsidiaries					Other Consolidated VIEs					
	SWEPCo Sabine	I&M DCC Fuel	OPCo Ohio Phase-in-Recovery Funding		APCo Appalachian Consumer Rate Relief Funding		AEP Credit	TCC Transition Funding		Protected Cell of EIS	Transource Energy
	(in millions)										
ASSETS											
Current Assets	$61.8	$109.2	$ 18.9		$ 11.8		$1,038.7	$ 163.5		$ 179.4	$ 12.2
Net Property, Plant and Equipment	123.6	165.9	—		—		—	—		—	298.5
Other Noncurrent Assets	63.9	78.8	128.1	(a)	314.7	(b)	10.3	1,210.4	(c)	1.7	5.5
Total Assets	$249.3	$353.9	$ 147.0		$ 326.5		$1,049.0	$ 1,373.9		$ 181.1	$ 316.2
LIABILITIES AND EQUITY											
Current Liabilities	$32.0	$98.2	$ 46.9		$ 25.0		$948.2	$ 242.6		$ 47.7	$ 35.4
Noncurrent Liabilities	217.0	255.7	98.8		300.2		0.6	1,113.2		91.1	127.2
Equity	0.3	—	1.3		1.3		100.2	18.1		42.3	153.6

Total Liabilities and Equity	$249.3	$353.9	$ 147.0	$ 326.5	$1,049.0	$ 1,373.9	$ 181.1	$ 316.2

(a) Includes an intercompany item eliminated in consolidation of $60.2 million.
(b) Includes an intercompany item eliminated in consolidation of $3.8 million.
(c) Includes an intercompany item eliminated in consolidation of $62.9 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2015

	Registrant Subsidiaries				Other Consolidated VIEs			
	SWEPCo Sabine	I&M DCC Fuel	OPCo Ohio Phase-in-Recovery Funding	APCo Appalachian Consumer Rate Relief Funding	AEP Credit	TCC Transition Funding	Protected Cell of EIS	Transource Energy
	(in millions)							
ASSETS								
Current Assets	$61.7	$91.1	$ 31.2	$ 18.5	$925.7	$ 234.1	$ 165.3	$ 10.8
Net Property, Plant and Equipment	147.0	159.9	—	—	—	—	—	227.2
Other Noncurrent Assets	61.8	84.6	162.0 (a)	332.0 (b)	6.4	1,365.7 (c)	1.9	5.5
Total Assets	$270.5	$335.6	$ 193.2	$ 350.5	$932.1	$ 1,599.8	$ 167.2	$ 243.5
LIABILITIES AND EQUITY								
Current Liabilities	$47.7	$84.8	$ 47.3	$ 27.1	$855.1	$ 291.7	$ 41.8	$ 36.6
Noncurrent Liabilities	222.3	250.8	144.6	321.5	0.3	1,290.0	83.9	113.0
Equity	0.5	—	1.3	1.9	76.7	18.1	41.5	93.9
Total Liabilities and Equity	$270.5	$335.6	$ 193.2	$ 350.5	$932.1	$ 1,599.8	$ 167.2	$ 243.5

(a) Includes an intercompany item eliminated in consolidation of $76.1 million.
(b) Includes an intercompany item eliminated in consolidation of $4.0 million.
(c) Includes an intercompany item eliminated in consolidation of $68.2 million.

Non-Consolidated Significant Variable Interests

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 September 30, 2016 and 2015 were $15 million and $30 million, respectively, and for the nine months ended September 30, 2016 and 2015 were $43 million and $59 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 balance sheets.

SWEPCo's investment in DHLC was:

	September 30, 2016		December 31, 2015	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure

	(in millions)			
Capital Contribution from SWEPCo	$7.6	$ 7.6	$7.6	$ 7.6
Retained Earnings	12.7	12.7	7.7	7.7
SWEPCo’s Guarantee of Debt	—	92.7	—	82.9
Total Investment in DHLC	$20.3	$ 113.0	$15.3	$ 98.2

AEP and FirstEnergy Corp. (FirstEnergy) have a joint venture in Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct, through its operating companies, a high-voltage transmission line project in the PJM region. PATH consists of the “West Virginia Series (PATH-WV),” owned equally by subsidiaries of FirstEnergy and AEP, and the “Allegheny Series” which is 100% owned by a subsidiary of FirstEnergy. Provisions exist within the PATH-WV agreement that make it a VIE. AEP has no interest or control in the “Allegheny Series”. AEP is not required to consolidate PATH-WV as AEP is not the primary beneficiary, although AEP holds a significant variable interest in PATH-WV. AEP’s equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the balance sheets. AEP and FirstEnergy share the returns and losses equally in PATH-WV. AEP’s 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. In April 2015, PATH filed a stipulation agreement with the FERC that agreed to a 50% debt and 50% equity capital structure and a 4.7% cost of long-term debt for the entire amortization period. In September 2015, the Administrative Law Judge who conducted the hearings issued an Initial Decision, which if adopted by the FERC, would deem certain costs not recoverable. The Initial Decision has no binding effect. Additional briefing was submitted during the fourth quarter of 2015. The case is currently pending before FERC. Depending on the outcome of this proceeding, PATH-WV may be required to refund certain amounts that have been collected under its formula rate. Management believes its financial statements adequately address the potential impact of this proceeding.

AEP's investment in PATH-WV was:

	September 30, 2016		December 31, 2015	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$18.8	$ 18.8	$18.8	$ 18.8
Retained Earnings	2.2	2.2	2.2	2.2
Total Investment in PATH-WV	$21.0	$ 21.0	$21.0	$ 21.0

As of September 30, 2016, AEP's $21 million investment in PATH-WV was included in Deferred Charges and Other Noncurrent Assets on the balance sheet. If AEP cannot ultimately recover the investment related to PATH-WV, it could reduce future net income and cash flows.

AEPSC provides certain managerial and professional services to AEP's subsidiaries. Parent 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	Nine Months Ended

	Ended September 30,		September 30,	
Company	2016	2015	2016	2015
	(in millions)			
APCo	$55.3	$63.7	$165.7	$164.7
I&M	32.7	37.5	97.7	102.1
OPCo	39.4	48.5	123.2	128.6
PSO	23.6	29.9	77.1	77.8
SWEPCo	31.4	39.2	101.2	102.6

206

The carrying amount and classification of variable interest in AEPSC's accounts payable are as follows:

Company	September 30, 2016		December 31, 2015	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
APCo	$20.0	$ 20.0	$25.8	$ 25.8
I&M	11.0	11.0	16.6	16.6
OPCo	13.9	13.9	23.3	23.3
PSO	7.8	7.8	12.6	12.6
SWEPCo	11.8	11.8	16.4	16.4

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. Total billings to I&M from AEGCo for the three months ended September 30, 2016 and 2015 were $65 million and $67 million, respectively, and for the nine months ended September 30, 2016 and 2015 were $166 million and $182 million, respectively. The carrying amount of I&M's liabilities associated with AEGCo as of September 30, 2016 and December 31, 2015 was $17 million and $17 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability. For additional information regarding AEGCo's lease, see "Rockport Lease" section of Note 13 in the 2015 Annual Report. The assets and liabilities of AEGCo's Lawrenceburg Plant have been recorded as Assets Held for Sale and Liabilities Held for Sale, respectively, on the balance sheet as of September 30, 2016. See "Assets and Liabilities Held For Sale" section of Note 6 for additional information.

CONTROLS AND PROCEDURES

During the third quarter of 2016, management, including the principal executive officer and principal financial officer of each of 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 September 30, 2016, 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.

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 third quarter of 2016 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, 2015 includes a detailed discussion of risk factors. As of September 30, 2016, there have been no material changes to the risk factors previously disclosed in the 2015 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 was subject to the provisions of the Mine Act for the quarter ended September 30, 2016.

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 under the Mine Act for the quarter ended September 30, 2016.

Item 5. Other Information

None

Item 6. Exhibits

10(a) – AEP Long-Term Incentive Plan Amended and Restated as of September 21, 2016
10(b) – Purchase and Sale Agreement by and among AEP Generation Resources Inc., AEP Generating Company and Burgandy Power LLC dated as of September 13, 2016
10(c) – Change in Control Agreement
10(d) – Executive Severance Plan

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: November 1, 2016