AMERICAN ELECTRIC POWER CO INC
Form 10-Q
October 27, 2017

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, 2017
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
333-217143	AEP TRANSMISSION COMPANY, LLC (A Delaware Limited Liability Company)	46-1125168
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 the American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ (Do not check if a smaller reporting company)

Smaller reporting company ¨ Emerging growth company ¨

Indicate by check mark whether AEP Transmission Company, LLC, 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, smaller reporting companies, or emerging growth companies. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer x (Do not check if a smaller reporting company)

Smaller reporting company ¨ Emerging growth company ¨

If an emerging growth company, indicate by check mark if the registrants have elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

Indicate by check mark whether

the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

AEP Transmission Company, LLC, 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 October 26, 2017
American Electric Power Company, Inc.	491,883,887 ($6.50 par value)
AEP Transmission Company, LLC (a)	NA
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)

(a) 100% interest is held by AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of American Electric Power Company, Inc.
NA Not applicable.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF QUARTERLY REPORTS ON FORM 10-Q
September 30, 2017

Part II. OTHER INFORMATION

This combined Form 10-Q is separately filed by American Electric Power Company, Inc., AEP Transmission Company, LLC, 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 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 Texas	AEP Texas Inc., an AEP electric utility subsidiary.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEPRO	AEP River Operations, LLC, a commercial barge operation sold in November 2015.
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.
AEPTCo Parent	AEP Transmission Company, LLC, the equity owner of the State Transcos within the AEPTCo consolidation.
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.
CAIR	Clean Air Interstate Rule.
CO_2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,278 MW nuclear plant owned by I&M.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel VI LLC, DCC Fuel VII, DCC Fuel VIII, DCC Fuel IX and DCC Fuel X, consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
DIR	Distribution Investment Rider.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
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.

Term	Meaning
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between Parent and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
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.
kV	Kilovolt.
KWh	Kilowatthour.
LPSC	Louisiana Public Service Commission.
Market Based Mechanism	An order from the LPSC established to evaluate proposals to construct or acquire generating capacity. The LPSC directs that the market based mechanism shall be a request for proposal competitive solicitation process.
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.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
Ohio Phase-in-Recovery Funding	Ohio Phase-in-Recovery Funding LLC, a wholly-owned subsidiary of OPCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to phase-in recovery property.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
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.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.

PM	Particulate Matter.
PPA	Purchase Power and Sale Agreement.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.

Term	Meaning
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants: AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
Registrants	SEC registrants: AEP, AEPTCo, 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.
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.
State Transcos	AEPTCo’s seven wholly-owned, FERC-regulated, transmission-only electric utilities, each of which is geographically aligned with AEP existing utility operating companies.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	Formerly AEP Texas Central Company, now a division of AEP Texas.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	Formerly AEP Texas North Company, now a division of AEP Texas.
Transition Funding	AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation.
Transource Energy	Transource Energy, LLC, a consolidated variable interest entity formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Transource Missouri	A 100% wholly-owned subsidiary of Transource Energy.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
Virginia SCC	Virginia State Corporation Commission.
Wind Catcher Project	Wind Catcher Energy Connection Project, a joint PSO and SWEPCo project which includes the acquisition of a wind generation facility, totaling approximately 2,000 MW of wind generation, and the construction of a generation interconnection tie-line totaling approximately 350 miles.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

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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 2016 Annual Report and “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in AEPTCo’s 2016 Annual Report included within AEPTCo’s Registration Statement, but there are others throughout this document which may be identified by words such as “expect,” “anticipate,” “intend,” “plan,” “believe,” “will,” “should,” “could,” “would,” “project,” “continue” and simila 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:

Economic 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 and customer growth.

Weather conditions, including storms and drought conditions, and the ability to recover significant storm restoration costs.

The cost of fuel and its transportation, the creditworthiness and performance of fuel suppliers and transporters and the cost of storing and disposing of used fuel, including coal ash and spent nuclear fuel.

Availability of necessary generation capacity, the performance of generation plants and the availability of fuel, including processed nuclear fuel, parts and service from reliable vendors.

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 any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.

Volatility and changes in markets for capacity and electricity, coal and other energy-related commodities, particularly changes in the price of natural gas.
Changes in utility regulation and the allocation of costs within regional transmission organizations, including ERCOT, PJM and SPP.
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 2016 Annual Report and in Part II of this report. Additionally, see “Risk Factors” in the AEPTCo 2016 Annual Report included within AEPTCo’s Registration Statement.

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 2017 decreased by 0.7% compared to the third quarter of 2016. AEP's third quarter 2017 industrial sales increased by 1.7% compared to the third quarter of 2016. The growth in industrial sales was spread across many industries and most operating companies. Weather-normalized residential sales decreased 2.4% in the third quarter of 2017 compared to the third quarter of 2016. Weather-normalized commercial sales decreased by 1.3% in the third quarter of 2017 compared to the third quarter of 2016.

AEP's weather-normalized retail sales volumes for the nine months ended September 30, 2017 decreased by 0.4% compared to the nine months ended September 30, 2016. AEP's industrial sales volumes for the nine months ended September 30, 2017 increased 1.6% compared to the nine months ended September 30, 2016. The growth in industrial sales was spread across many industries and most operating companies. Weather-normalized residential and commercial sales decreased 1.5% and 1.4%, respectively, for the nine months ended September 30, 2017 compared to the nine months ended September 30, 2016.

Merchant Generation Assets

In September 2016, AEP signed an agreement to sell Darby, Gavin, Lawrenceburg and Waterford Plants ("Disposition Plants") totaling 5,329 MWs of competitive generation to a nonaffiliated party. The sale closed in January 2017 for approximately $2.2 billion. The net proceeds from the transaction were approximately $1.2 billion in cash after taxes, repayment of debt associated with these assets and transaction fees, which resulted in an after tax gain of approximately $129 million. AEP primarily used these proceeds to reduce outstanding debt and invest in its regulated businesses including transmission, and contracted renewable projects.

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 December 31, 2016. See "Assets and Liabilities Held for Sale" section of Note 6 for additional information.

In February 2017, AEP signed an agreement to sell its 25.4% ownership share of Zimmer Plant to Dynegy Corporation. Simultaneously, AEP signed an agreement to purchase Dynegy Corporation's 40% ownership share of Conesville Plant, Unit 4. The transactions closed in the second quarter of 2017 and did not have a material impact on net income, cash flows or financial condition.

Management continues to evaluate potential alternatives for the remaining merchant generation assets. These potential alternatives may include, but are not limited to, transfer or sale of AEP's ownership interests, or a wind down of merchant coal-fired generation fleet operations. 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.

Contracted Renewable Generation Facilities

AEP utilizes two 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 creditworthy counterparty. AEP Renewables, LLC develops and/or acquires large scale renewable generation projects that are backed with long-term contracts with creditworthy counterparties. As of September 30, 2017, these subsidiaries have approximately 148 MWs of renewable generation projects in operation and $292 million of capital costs have been incurred related to these projects. In addition, as of September 30, 2017, these subsidiaries have approximately 42 MWs of renewable generation projects under construction and estimated capital costs of $54 million related to these projects. As of September 30, 2017, total estimated capital costs related to these renewable generation projects were approximately $346 million.

Regulated Renewable Generation Facilities

In July 2017, APCo submitted filings with the Virginia SCC and the WVPSC requesting regulatory approval to acquire two wind generation facilities totaling approximately 225 MW of wind generation. The wind generating facilities are located in West Virginia and Ohio and, if approved, are anticipated to be in-service in the second half of 2019. APCo will assume ownership of the facilities at or near the anticipated in-service date. APCo currently plans to sell the Renewable Energy Certificates associated with the generation from these facilities.

In July 2017, PSO and SWEPCo submitted filings with the OCC, LPSC, APSC and PUCT requesting various regulatory approvals needed to fully proceed with the Wind Catcher Project. The Wind Catcher Project includes the acquisition of a wind generation facility, totaling approximately 2,000 MW of wind generation, and the construction of a generation interconnection tie-line totaling approximately 350 miles. Total investment for the project is estimated to be $4.5 billion and will serve both retail and FERC wholesale load. PSO and SWEPCo will have a 30% and 70% ownership share, respectively, in these assets. The wind generating facility is located in Oklahoma and, if approved by all state commissions, is anticipated to be in-service by the end of 2020. In July 2017, the LPSC approved SWEPCo’s request for an exemption to the Market Based Mechanism. In August 2017, the Oklahoma Attorney General filed a motion to dismiss with the OCC. In August 2017, the motion to dismiss was denied by the OCC. Hearings at the APSC, LPSC, OCC and PUCT are scheduled in the first quarter of 2018.

Hurricane Harvey

In August 2017, Hurricane Harvey hit the coast of Texas, causing power outages in the AEP Texas service territory. As restoration efforts are ongoing, AEP Texas’ total costs related to this storm are not yet known. AEP Texas’ current estimated cost is approximately $250 million to $300 million, including capitalized expenditures. AEP Texas currently estimates that it will incur approximately $90 million of operation and maintenance costs related to service restoration efforts. AEP Texas has a PUCT approved catastrophe reserve in base rates and can defer incremental storm expenses. AEP Texas currently recovers approximately $1 million of storm costs annually through base rates. As of September 30, 2017, the total balance of AEP Texas’ deferred storm costs is approximately $97 million including approximately $73 million of incremental storm expenses as a regulatory asset related to Hurricane Harvey. Management is currently in the early stages of analyzing the impact of potential insurance claims and recoveries and, at this time, cannot estimate this amount. Any future insurance recoveries received will be applied to and will offset the regulatory asset and property, plant and equipment, as applicable. AEP Texas is currently evaluating recovery options for the regulatory asset; however, management believes the asset is probable of recovery. The other named hurricanes did not have a material impact on AEP’s operations in the third quarter of 2017. If the ultimate costs of the incident are not recovered by insurance or through the regulatory process, it could have an adverse effect on future net income, cash flows and financial condition.

Merchant Portion of Turk Plant

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

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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 (subject to prudence review) and through SWEPCo's wholesale customers under FERC-based rates. As of September 30, 2017, the net book value of Turk Plant was $1.5 billion, before cost of removal, including materials and supplies inventory and CWIP. In October 2017, the LPSC staff filed a prudence review of the Turk Plant. See "Louisiana Turk Plant Prudence Review" section of Note 4.

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.

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 subject to audit and review by the PUCO. Consistent with the terms of a modified and approved stipulation agreement, and based upon a September 2016 PUCO order, in November 2016, OPCo refiled its amended ESP extension application and supporting testimony. The amended filing proposed to extend the ESP through May 2024 and included (a) an extension of the OVEC PPA rider, (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 Renewable Resource Rider.

In August 2017, OPCo and various intervenors filed a stipulation agreement with the PUCO. The stipulation extends the term of the ESP through May 2024 and includes: (a) an extension of the OVEC PPA rider, (b) a proposed 10% 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) rate caps related to OPCo's DIR ranging from $215 million to $290 million for the periods 2018 through 2021, (e) the addition of various new riders, including a Smart City Rider and a Renewable Generation Rider, (f) a decrease in annual depreciation rates based on a depreciation study using data through December 2015 and (g) amortization of approximately $24 million annually beginning January 2018 of OPCo's excess distribution accumulated depreciation reserve, which was $239 million as of December 31, 2015. Upon PUCO approval of the stipulation, effective January 2018, OPCo will cease recording $39 million in annual amortization previously approved to end in December 2018 in accordance with PUCO's December 2011 OPCo distribution base rate case order. In the stipulation, OPCo and intervenors agree that OPCo can request in future proceedings a change in meter depreciation rates due to retired meters pursuant to the smart grid Phase 2 project. DIR rate caps will be reset in OPCo's next distribution base rate case which must be filed by June 2020.

In October 2017, intervenor testimony opposing the stipulation agreement was filed recommending: (a) a return on common equity to not exceed 9.3% for riders earning a return on capital investments, (b) that OPCo should file a base distribution case concurrent with the conclusion of the current ESP in May 2018 and (c) denial of certain new riders proposed in OPCo's ESP extension. The stipulation is subject to review by the PUCO. A hearing at the PUCO is scheduled for November 2017.

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.

2016 SEET Filing

In December 2016, OPCo recorded a 2016 SEET provision of $58 million based upon projected earnings data for companies in the comparable utilities risk group. In determining OPCo's return on equity in relation to the comparable utilities risk group, management excluded the following items resolved in OPCo's Global Settlement: (a) gain on the deferral of RSR costs, (b) refunds to customers related to the SEET remands and (c) refunds to customers related to fuel adjustment clause proceedings. In May 2017, OPCo submitted its 2016 SEET filing with the PUCO in which management indicated that OPCo did not have significantly excessive earnings in 2016 based upon actual earnings data for the comparable utilities risk group. Although management believes that OPCo's adjusted 2016 earnings were not excessive, management did not adjust OPCo's 2016 SEET provision due to risks that the PUCO could rule against OPCo's SEET treatment of the Global Settlement issues described above or adopt a different 2016 SEET threshold. If the PUCO orders a refund of 2016 OPCo earnings, it could reduce future net income and cash flows and impact financial condition. See "2016 SEET Filing" section of Note 4.

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. As of September 30, 2017, total costs incurred related to this project, including AFUDC, were approximately $17 million. The filing included a request for authorization for I&M to defer its Indiana jurisdictional ownership share of costs including investment carrying costs at a weighted average cost of capital (WACC), depreciation over a 10-year period as provided by statute and other related expenses. I&M proposed recovery of these costs using the existing Clean Coal Technology Rider in a future filing subsequent to approval of the SCR project. The AEGCo ownership share of the proposed SCR project will be billable under the Rockport Unit Power Agreement to I&M and KPCo and will be subject to future regulatory approval for recovery. In February 2017, the Indiana Office of Utility Consumer Counselor (OUCC) and other parties filed testimony with the IURC. The OUCC recommended approval of the CPCN but also stated that any decision regarding recovery of any under-depreciated plant due to retirement should be fully investigated in a base rate case, not in a tracker or other abbreviated proceeding. The other parties recommended either denial of the CPCN or approval of the CPCN with conditions including a cap on the amount of SCR costs allowed to be recovered in the rider and limitations on other costs related to legal issues involving the Rockport Plant, Unit 2 lease. A hearing at the IURC was held in March 2017. An order from the IURC is pending. In July 2017, I&M filed a motion with the U.S. District Court for the Southern District of Ohio to remove the requirement to install SCR technology at Rockport Plant, Unit 2. In August 2017, the district court delayed the deadline for installation of the SCR technology until March 2020.

2017 Indiana Base Rate Case

In July 2017, I&M filed a request with the IURC for a $263 million annual increase in Indiana rates based upon a proposed 10.6% return on common equity with the annual increase to be implemented after June 2018. Upon implementation, this proposed annual increase would be subject to a temporary offsetting $23 million annual reduction to customer bills through December 2018 for a credit adjustment rider related to the timing of estimated in-service dates of certain capital expenditures. The proposed annual increase includes $78 million related to increased annual depreciation rates and an $11 million increase related to the amortization of certain Cook Plant and Rockport Plant regulatory assets. The increase in depreciation rates includes a change in the expected retirement date for Rockport Plant, Unit 1 from 2044 to 2028 combined with increased investment at the Cook Plant, including the Cook Plant Life Cycle Management Project. A hearing at the IURC is scheduled for January 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2017 Michigan Base Rate Case

In May 2017, I&M filed a request with the MPSC for a $52 million annual increase in Michigan base rates based upon a proposed 10.6% return on common equity with the increase to be implemented no later than April 2018. The proposed annual increase includes $23 million related to increased annual depreciation rates and a $4 million increase related to the amortization of certain Cook Plant regulatory assets. The increase in depreciation rates is primarily due to the proposed change in the expected retirement date for Rockport Plant, Unit 1 from 2044 to 2028 combined with increased investment at the Cook Plant related to the Life Cycle Management Project. Additionally, the total proposed increase includes incremental costs related to the Cook Plant Life Cycle Management Program and increased vegetation management expenses. In October 2017, the MPSC staff and intervenors filed testimony. The MPSC staff recommended an annual net revenue increase of $49 million including proposed retirement dates of 2028 for both Rockport Plant, Units 1 (from 2044) and 2 (from 2022) and a return on common equity of 9.8%. The intervenors proposed certain adjustments to I&M’s request including no change to the current 2044 retirement date of Rockport Plant, Unit 1, but did not propose an annual net revenue increase. Their recommended return on common equity ranged from 9.3% to 9.5%. A hearing at the MPSC is scheduled for November 2017. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Louisiana Turk Plant Prudence Review

Beginning January 2013, SWEPCo’s formula rates, including the Louisiana jurisdictional share (approximately 33%) of the Turk Plant, have been collected subject to refund pending the outcome of a prudence review of the Turk Plant investment, which was placed into service in December 2012. In October 2017, the LPSC staff filed testimony contending that SWEPCo failed to continue to evaluate the suspension or cancellation of the Turk Plant during its construction period. The testimony also identified five individual items totaling approximately $51 million for potential disallowance relating to Louisiana’s jurisdictional share of Turk Plant. As a result of SWEPCo’s alleged failure to meet its continuing prudence obligations, the LPSC staff recommends one of the following potential unfavorable scenarios: (a) 50/50 sharing of construction cost overruns between SWEPCo and ratepayers, (b) an imposition of a cost cap similar to Texas or (c) approximately a 1% reduction of the rate on common equity for the Turk Plant. As SWEPCo has included the full value of the Turk Plant in rate base since its in-service date, SWEPCo may be required to refund potential over-collections from January 2013 through the date new rates are implemented. As of September 30, 2017, if the LPSC adopts one of these potential scenarios, and disallows the five individual items, pretax write-offs could range from $50 million to $80 million and refund provisions, including interest, could range from $15 million to $27 million. Future annual revenue reductions could range from $3 million to $4 million. Management will continue to vigorously defend against these claims. If the LPSC orders in favor of one of these scenarios, it could reduce future net income and cash flows and impact financial condition. A hearing at the LPSC is scheduled for December 2017.

2017 Oklahoma Base Rate Case

In June 2017, PSO filed an application for a base rate review with the OCC that requested a net increase in annual revenues of $156 million based upon a proposed 10% return on common equity. The proposed base rate increase includes (a) environmental compliance investments, including recovery of previously deferred environmental compliance related costs currently recorded as regulatory assets, (b) Advanced Metering Infrastructure investments, (c) additional capital investments and costs to serve PSO’s customers, and (d) an annual $42 million depreciation rate increase due primarily to shorter service lives and lower net salvage estimates. As part of this filing, consistent with the OCC’s final order in its previous base rate case, PSO requested recovery through 2040 of Northeastern Plant, Unit 3, including the environmental control investment, and the net book value of Northeastern Plant, Unit 4 that was retired in 2016. As of September 30, 2017, the net book value of Northeastern Plant, Unit 4 was $82 million.

In September 2017, various intervenors and the OCC staff filed testimony that included annual net revenue increase recommendations ranging from $28 million to $108 million. The recommended returns on common equity ranged from 8% to 9%. In addition, certain parties recommended investment disallowances that ranged from $27 million to $82 million related to Northeastern Plant, Unit 4 and $38 million associated with capitalized incentives. Also, a party recommended a potential refund of $43 million related to an SPP rider claiming that PSO did not adequately support the related SPP costs. The combined total impact could result in a write-off and refund of up to approximately $163 million. In addition, if similar plant recovery issues would apply to Northeastern Plant, Unit 3, the net book value of plant, including regulatory assets, materials and supplies inventory and CWIP of $346 million as of September 30, 2017, could be adversely impacted. A hearing at the OCC is scheduled to begin in October 2017.

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

2017 Kentucky Base Rate Case

In June 2017, KPCo filed a request with the KPSC for a $66 million annual increase in Kentucky base rates based upon a proposed 10.31% return on common equity with the increase to be implemented no later than January 2018. The proposed increase includes: (a) lost load since KPCo last changed base rates in July 2015, (b) incremental costs

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related to OATT charges from PJM not currently recovered from retail ratepayers, (c) increased depreciation expense including updated Big Sandy Plant, Unit 1 depreciation rates using a proposed retirement date of 2031, (d) recovery of other Big Sandy Plant, Unit 1 generation costs currently recovered through a retail rider and (e) incremental purchased power costs. Additionally, KPCo requested a $4 million annual increase in environmental surcharge revenues.

In August 2017, KPCo submitted a supplemental filing with the KPSC that decreased the proposed annual base rate revenue request to $60 million. The modification was due to a lower interest expense related to June 2017 debt refinancings. In October 2017, various intervenors filed testimony that included annual net revenue increase recommendations ranging from $13 million to $40 million. Intervenors recommended returns on common equity ranging from 8.6% to 8.85%. Intervenors also recommended significant delays in KPCo’s proposed recoveries of: (a) depreciation expense related to Big Sandy Plant, Unit 1 (gas unit), proposing a 30-year depreciable life instead of KPCo’s proposed 15-year life and (b) lease expense on Rockport Plant, Unit 2 billed from AEGCo, proposing that the approximate $100 million of lease expense for the period 2018 through 2022 be deferred with a WACC carrying charge for recovery over 10 years beginning 2023. Testimony on behalf of the Attorney General also discussed that the KPSC could consider disallowing all or a portion of the costs currently being recovered over 25 years through the Big Sandy Plant, Unit 2 retirement rider. As of September 30, 2017, KPCo’s regulatory asset related to the retired Big Sandy Plant, Unit 2 was $289 million. A hearing at the KPSC is scheduled for December 2017.

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

2016 Texas Base Rate Case

In December 2016, SWEPCo filed a request with the PUCT for a net increase in Texas annual revenues of $69 million based upon a 10% return on common equity. In September 2017, the Administrative Law Judges (ALJs) issued their proposal for decision including an annual net revenue increase of $50 million including recovery of Welsh Plant, Unit 2 environmental investments as of June 30, 2016. The ALJs proposed a return on common equity of 9.6% and recovery of but no return on Welsh Plant, Unit 2. The ALJs rejected SWEPCo’s proposed transmission cost recovery mechanism. The estimated potential write-off associated with the ALJs proposal is approximately $22 million which includes $9 million associated with the lack of a return on Welsh Plant, Unit 2.

If any of these costs are not recoverable, including environmental investments and retirement-related costs for Welsh Plant, Unit 2, it could reduce future net income and cash flows and impact financial condition. See “2016 Texas Base Rate Case” section of Note 4.

FERC Transmission Complaint - AEP’s PJM Participants

In October 2016, several parties filed a joint complaint at the FERC that states the base return on common equity used by AEP’s eastern transmission subsidiaries in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. Management believes its financial statements adequately address the impact of the complaint. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

Modifications to AEP’s PJM Transmission Rates

In November 2016, AEP’s eastern transmission subsidiaries filed an application at the FERC to modify the PJM OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to projected expenses. In March 2017, the FERC accepted the proposed modifications effective

January 1, 2017, subject to refund, and set this matter for hearing and settlement procedures. Effective January 1, 2017, the modified PJM OATT formula rates were implemented, subject to refund, based on projected 2017 calendar year financial activity and projected plant balances. If the FERC determines that any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

FERC Transmission Complaint - AEP's SPP Participants

In June 2017, several parties filed a joint complaint at the FERC that states the base return on common equity used by AEP's western transmission subsidiaries in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.36%, effective upon the date of the complaint. Management believes its financial statements adequately address the impact of the complaint. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

FERC SWEPCo Power Supply Agreements Complaint - East Texas Electric Cooperative, Inc. (ETEC) and Northeast Texas Electric Cooperative, Inc. (NTEC)

In September 2017, ETEC and NTEC filed a complaint at the FERC that states the base return on common equity used by SWEPCo in calculating their power supply formula rates is excessive and should be reduced from 11.1% to 8.41%, effective upon the date of the complaint. Management believes its financial statements adequately address the impact of the complaint. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

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 total approximately $850 million, excluding AFUDC. As of September 30, 2017, SWEPCo had incurred costs of $398 million, including AFUDC, related to these projects. Management continues to evaluate the impact of environmental rules and related project cost estimates. As of September 30, 2017, the total net book value of Welsh Plant, Units 1 and 3 was $626 million, before cost of removal, including materials and supplies inventory and CWIP.

In 2016, as approved by the APSC, SWEPCo began recovering $79 million related to the Arkansas jurisdictional share of these environmental costs, subject to prudence review in the next Arkansas filed base rate proceeding. In December 2016, the LPSC approved deferral of certain expenses related to the Louisiana jurisdictional share of environmental controls installed at Welsh Plant. In April 2017, the LPSC approved SWEPCo's recovery of these deferred costs effective May 2017. SWEPCo's approved Louisiana jurisdictional share of Welsh Plant deferrals: (a) are $11 million, excluding $6 million of unrecognized equity as of September 30, 2017, (b) is subject to review by the LPSC, and (c) includes a WACC return on environmental investments and the related depreciation expense and taxes. Effective May 2017, SWEPCo began recovering $131 million in investments related to its Louisiana jurisdictional share of environmental costs. SWEPCo has sought recovery of its project costs from retail customers in its current Texas base rate case at the PUCT and is recovering these costs from wholesale customers through SWEPCo's FERC-approved agreements.

If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See "Welsh Plant - Environmental Impact" section of Note 4.

Westinghouse Electric Company Bankruptcy Filing

In March 2017, Westinghouse filed a petition to reorganize under Chapter 11 of the U.S. Bankruptcy Code. It intends to reorganize, not cease business operations. However, it is in the early stages of the bankruptcy process and it is unclear whether the company can successfully reorganize. Westinghouse and I&M have a number of significant ongoing contracts relating to reactor services, nuclear fuel fabrication, and ongoing engineering projects. The most significant of these relate to Cook Plant fuel fabrication. I&M is evaluating how this reorganization affects these contracts. Westinghouse has stated that it intends to continue performance on I&M’s contracts, but given the importance of upcoming dates in the fuel fabrication process for Cook Plant, and their vital part in Cook Plant’s ongoing operations, I&M continues to work with Westinghouse in the bankruptcy proceedings to avoid any interruptions to that service. In the unlikely event Westinghouse rejects I&M’s contracts, or is unable to reorganize or sell its profitable businesses in the bankruptcy, Cook Plant’s operations would be significantly impacted and potentially shut down temporarily as I&M seeks other vendors for these services.

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 2016 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 plaintiffs further allege that the defendants' actions constitute breach of the lease and participation agreement. The plaintiffs seek a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M.

In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiffs' claims, including the dismissal without prejudice of plaintiffs' claims seeking compensatory damages. 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 plaintiffs 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 plaintiffs' 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 an appeal in the U.S. Court of Appeals for the Sixth Circuit 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.

In April 2017, the U.S. Court of Appeals for the Sixth Circuit issued an opinion reversing the district court's decisions which had dismissed certain of plaintiffs' claims for breach of contract and remanding the case to the district court to enter summary judgment in plaintiffs' favor consistent with that ruling. In April 2017, AEGCo and I&M filed a petition for rehearing with the U.S. Court of Appeals for the Sixth Circuit, which was granted. In June 2017, the U.S.

Court of Appeals for the Sixth Circuit issued an amended opinion and judgment which reverses the district court's dismissal of certain of the owners' claims under the lease agreements, vacates the denial of the owners' motion for partial summary judgment and remands the case to the district court for further proceedings. The amended opinion and judgment also affirms the district court's dismissal of the owners' breach of good faith and fair dealing claim as duplicative of the breach of contract claims and removes the instruction to the district court in the original opinion to enter summary judgment in favor of the owners.

In July 2017, AEP filed a motion with the U.S. District Court for the Southern District of Ohio seeking to modify the consent decree to eliminate the obligation to install future controls at Rockport Plant, Unit 2 if AEP does not acquire ownership of that Unit, and to modify the consent decree in other respects to preserve the environmental benefits of the consent decree. In October 2017, the owners filed a motion to stay their claims until January 2018, to afford time for resolution of AEP's motion to modify the consent decree.

Management will continue to defend against the claims. Given that the district court dismissed plaintiffs' claims seeking compensatory relief as premature, and that plaintiffs have yet to present a methodology for determining or any analysis supporting any alleged damages, management is unable to determine a range of potential losses that are reasonably possible of occurring.

ENVIRONMENTAL ISSUES

AEP has a substantial capital investment program and is 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 new CAA requirements to reduce emissions 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. 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 2016 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, 2017, the AEP System had a total generating capacity of approximately 25,600 MWs, of which approximately 13,500 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 existing and proposed requirements ranges from approximately \$2.2 billion to \$2.8 billion between 2017 and 2025.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in finalizing proposed rules or reviewing and revising certain existing requirements. 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.

The table below represents the plants or units of plants retired in 2016 and 2015 with a remaining net book value. As of September 30, 2017, the net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of the units listed below was approved for recovery, except for $338 million. Management is seeking or will seek recovery of the remaining net book value associated with these plants in future rate proceedings.

Company	Plant Name and Unit	Generating Capacity (in MWs)	Amounts Pending Regulatory Approval (in millions)
APCo	Kanawha River Plant	400	$ 42.3
APCo	Clinch River Plant, Unit 3	235	32.7
APCo (a)	Clinch River Plant, Units 1 and 2	470	31.8
APCo	Sporn Plant	600	17.2
APCo	Glen Lyn Plant	335	13.4
I&M (b)	Tanners Creek Plant	995	42.6
PSO (c)	Northeastern Plant, Unit 4	470	82.4
SWEPCo (d)	Welsh Plant, Unit 2	528	75.9
Total		4,033	$ 338.3

(a) 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 2015, APCo retired the coal-related assets of Clinch River Plant, Units 1 and 2. Clinch River Plant, Unit 1 and Unit 2 began operations as natural gas units in February 2016 and April 2016, respectively.

(b) I&M requested recovery of the Indiana (approximately 65%) and Michigan (approximately 14%) jurisdictional shares of the remaining retirement costs of Tanners Creek Plant in the 2017 Indiana and Michigan base rate cases.

(c) For Northeastern Plant, Unit 4, in November and December 2016, the OCC issued orders that provided no determination related to the return of and return on the post-retirement remaining net book value. In June 2017, PSO filed an application for a base rate review with the OCC. As part of this filing, PSO requested recovery of approximately $82 million through 2040 related to the net book value of Northeastern Plant, Unit 4 that was retired in 2016. This regulatory asset is pending regulatory approval.

(d) SWEPCo requested recovery of the Texas jurisdictional share (approximately 33%) of the net book value of Welsh Plant, Unit 2 in the 2016 Texas Base Rate Case. This regulatory asset is pending regulatory approval.

In January 2017, Dayton Power and Light Company announced the future retirement of the 2,308 MW Stuart Plant, Units 1-4. The retirement is scheduled for June 2018. Stuart Plant, Units 1-4 are operated by Dayton Power and Light Company and are jointly owned by AGR and nonaffiliated entities. AGR owns 600 MWs of the Stuart Plant, Units 1-4. As of September 30, 2017, AGR’s net book value of the Stuart Plant, Units 1-4 was zero.

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.

Proposed Modification of the New Source Review (NSR) Litigation Consent Decree

In 2007, the U.S. District Court for the Southern District of Ohio approved a consent decree between the AEP subsidiaries in the eastern area of the AEP System and the Department of Justice, the Federal EPA, eight northeastern states and other interested parties to settle claims that the AEP subsidiaries violated the NSR provisions of the CAA when it undertook various equipment repair and replacement projects over a period of nearly 20 years. The consent decree’s terms include installation of environmental control equipment on certain generating units, a declining cap on

SO_2 and NO_x emissions from the AEP System and various mitigation projects.

In July 2017, AEP filed a motion with the U.S. District Court for the Southern District of Ohio seeking to modify the consent decree to eliminate an obligation to install future controls at Rockport Plant, Unit 2 if AEP does not acquire ownership of that unit, and to modify the consent decree in other respects to preserve the environmental benefits of the consent decree. The district court granted AEP's request to delay the deadline to install SCR technology at Rockport Plant, Unit 2 until March 2020, pending resolution of the motion. AEP also proposes to retire Conesville Plant, Units 5 and 6 by December 31, 2022 and to retire one Rockport Plant unit by December 31, 2028.

AEP is seeking to modify the consent decree as a means to resolve or substantially narrow the issues in pending litigation with the owners of Rockport Plant, Unit 2. See "Rockport Plant Litigation" in Management's Discussion and Analysis of Financial Condition and Results of Operations and in Note 5 - Commitments, Guarantees and Contingencies for additional information.

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 primary regulatory programs that continue to drive investments in AEP's existing generating units include: (a) periodic revisions to the National Ambient Air Quality Standards (NAAQS) and the development of SIPs to achieve any more stringent standards; (b) implementation of the regional haze program by the states and the Federal EPA; (c) regulation of hazardous air pollutant emissions under the Mercury and Air Toxics Standards (MATS) Rule; (d) implementation and review of the Cross-State Air Pollution Rule (CSAPR), a FIP designed to eliminate significant contributions from sources in upwind states to nonattainment or maintenance areas in downwind states and (e) the Federal EPA's regulation of greenhouse gas emissions from fossil-fueled electric generating units under Section 111 of the CAA.

In March 2017, President Trump issued a series of executive orders designed to allow the Federal EPA to review and take appropriate action to revise or rescind regulatory requirements that place undue burdens on affected entities, including specific orders directing the Federal EPA to review rules that unnecessarily burden the production and use of energy. The Federal EPA published notice and an opportunity to comment on how to identify such requirements and what steps can be taken to reduce or eliminate such burdens. Future changes that result from this effort may affect AEP's compliance plans.

Notable developments in significant CAA regulatory requirements affecting AEP's operations are discussed in the following sections.

National Ambient Air Quality Standards (NAAQS)

The Federal EPA issued new, more stringent NAAQS for SO_2 in 2010, PM in 2012 and ozone in 2015. Implementation of these standards is underway. States are still in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the 2010 SO_2 NAAQS and may develop additional requirements for AEP's facilities as a result of those evaluations. In April 2017, the Federal EPA requested a stay of proceedings in the U.S. Court of Appeals for the District of Columbia Circuit where challenges to the 2015 ozone standard are pending, to allow reconsideration of that standard by the new administration. The Federal EPA initially announced a one-year delay in the designation of ozone non-attainment areas, but withdrew that decision. Final designations were due October 1, 2017, but have not yet been announced. Management cannot currently predict the nature, stringency or timing of additional requirements for AEP's facilities based on the outcome of these activities.

Regional Haze

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. In January 2017, the Federal EPA revised the rules governing submission of SIPs to implement the visibility programs, including a provision that postpones the due date for the next comprehensive SIP revisions until 2021. Petitions for review of the final rule revisions have been filed in the U.S. Court of Appeals for the District of Columbia Circuit.

The Federal EPA proposed disapproval of regional haze SIPs in a few states, including Arkansas and Texas. 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. The final rule is being challenged in the courts. In March 2017, the Federal EPA filed a motion that was granted by the U.S. Court of Appeals for the Eighth Circuit Court to hold the case in abeyance for 90 days to allow the parties to engage in settlement negotiations. Arkansas issued a proposed SIP revision to allow sources to participate in the CSAPR ozone season program in lieu of the source-specific NO_x BART requirements in the FIP, and the Federal EPA has proposed to approve that SIP revision. Arkansas and the Federal EPA have asked the Eighth Circuit to continue to hold litigation in abeyance until October 31, 2017 to facilitate settlement discussions. Management cannot predict the outcome of these proceedings.

In January 2016, the Federal EPA disapproved portions of the Texas regional haze SIP and promulgated a final FIP that did not include any BART determinations. That rule was challenged and stayed by the U.S. Court of Appeals for the Fifth Circuit Court. The parties engaged in a settlement discussion but were unable to reach an agreement. In March 2017, the U.S. Court of Appeals for the Fifth Circuit granted partial remand of the final rule. In January 2017, the Federal EPA proposed source-specific BART requirements for SO_2 from sources in Texas, including Welsh Plant, Unit 1. Management submitted comments on the proposal and is engaged in discussions with the Texas Commission on Environmental Quality (TCEQ) regarding the development of an alternative to source-specific BART. In September 2017, the Federal EPA issued a final rule withdrawing Texas from the annual CSAPR budget programs. The Federal EPA then issued a separate rule finalizing the regional haze requirements for electric generating units in Texas and confirmed TCEQ's determination that no new PM limitations are required for regional haze. The Federal EPA also finalized a FIP that allows participation in the CSAPR ozone season program to satisfy the NO_x regional haze obligations for electric generating units. Additionally, the Federal EPA finalized an intrastate SO_2 emissions trading program based on allowance allocations as an alternative to source-specific SO_2 requirements. The proposed source-specific approach called for a wet FGD system to be installed on Welsh Plant, Unit 1. The opportunity to use emissions trading to satisfy the regional haze requirements for NO_x and SO_2 at AEP's affected generating units provides greater flexibility and lower cost compliance options than the original proposal.

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.

Cross-State Air Pollution Rule (CSAPR)

In 2011, the Federal EPA issued CSAPR as a replacement for the CAIR, a regional trading program designed to address interstate transport of emissions that contributed significantly to downwind nonattainment with the 1997 ozone and PM NAAQS. 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. Interstate trading of allowances is allowed on a restricted sub-regional basis.

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. The court stayed implementation of the rule. Following extended proceedings in the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court, but while the litigation was still pending, the U.S. Court of Appeals for the District of Columbia Circuit granted the Federal EPA's 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. 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 October 2016, a final rule was issued to address the remand and to incorporate additional changes necessary to address the 2008 ozone standard. The final rule significantly reduces ozone season budgets in many states and discounts the value of banked CSAPR ozone season allowances beginning with the 2017 ozone season. The rule has been challenged in the courts and petitions for administrative reconsideration have been filed. The rule remains in effect. Management is complying with the more stringent ozone season budgets while these petitions are being considered.

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. Compliance was required within three years. Management obtained administrative extensions for up to one year at several units to facilitate the installation of controls or to avoid a serious reliability problem.

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 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. Oral argument was scheduled for May 2017, but in April 2017 the Federal EPA requested that oral argument be postponed to facilitate its review of the rule. 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 and solar installations and 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. 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 final rules are being challenged in the courts. In February 2016, the U.S. Supreme Court issued a stay on the final CPP, 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. In April 2017, the Federal EPA withdrew its previously issued proposals for model trading rules and a CEIP.

In March 2017, the Federal EPA filed in the U.S. Court of Appeals for the District of Columbia Circuit notice of: (a) an Executive Order from the President of the United States titled "Promoting Energy Independence and Economic Growth" directing the Federal EPA to review the CPP and related rules; (b) the Federal EPA's initiation of a review of the CPP and (c) a forthcoming rulemaking related to the CPP consistent with the Executive Order, if the Federal EPA determines appropriate. In this same filing, the Federal EPA also presented a motion to hold the litigation in abeyance until 30 days after the conclusion of review and any resulting rulemaking. The District of Columbia Circuit granted the Federal EPA's motion in part and has requested periodic status reports. In October 2017, the Federal EPA issued a proposed rule repealing the CPP and withdrawing the legal memoranda issued in connection with the rule. The Federal EPA has re-examined its legal interpretation of the "best system of emission reduction" and found that based on the statutory text, legislative history, use of similar terms elsewhere in the CAA and its own historic implementation of Section 111 that a narrower interpretation of the term limits it to those designs, processes, control technologies and other systems that can be applied directly to or at the source. Since the primary systems relied on in the CPP are not consistent with that interpretation, the Federal EPA proposes that the rule be withdrawn. Management does not expect a change in AEP's overall strategy as a result of the proposed repeal.

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 has been challenged in the courts.

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 to be implemented on a schedule spanning an approximate four year implementation period.

In December 2016, the U.S. Congress passed legislation authorizing states to submit programs to regulate CCR facilities, and the Federal EPA to approve such programs if they are no less stringent than the minimum federal standards. The Federal EPA may also enforce compliance with the minimum standards until a state program is approved or if states fail to adopt their own programs. In September 2017, the Federal EPA granted industry petitions to reconsider the CCR rule and asked that litigation regarding the rule be held in abeyance. The court has ordered oral argument to proceed in November 2017 and that the motion for abeyance be addressed during oral argument.

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.

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

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

In addition, the Federal EPA developed revised effluent limitation guidelines for electricity generating facilities. A final rule was issued in November 2015. The final rule establishes limits on FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater 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. The rule has been challenged in the U.S. Court of Appeals for the Fifth Circuit. In March 2017, industry associations filed a petition for reconsideration of the rule with the Federal EPA. In April 2017, the Federal EPA granted reconsideration of the rule and issued a stay of the rule's future compliance deadlines, which has now expired. In April 2017, the U.S. Court of Appeals for the Fifth Circuit granted a stay of the litigation for 120 days. In June 2017, the Federal EPA also issued a proposal to temporarily postpone certain compliance deadlines in the rule. A final rule revising the compliance deadlines for FGD wastewater and bottom ash transport water to be no earlier than 2020 was issued in September 2017. Management submitted comments supporting the proposed postponement. Management continues to assess technology additions and retrofits to comply with the rule and the impacts of the Federal EPA's recent actions on facilities' wastewater discharge permitting.

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. In January 2017, the decision was appealed to the U.S. Supreme Court, which granted certiorari to review the jurisdictional issue. The U.S. Supreme Court denied the Federal EPA's motion to hold briefing in abeyance pending further Federal EPA actions on the rule and the appeal on the jurisdictional issue continues.

In March 2017, the Federal EPA published a notice of intent to review the rule and provide an advanced notice of a proposed rulemaking consistent with the Executive Order of the President of the United States directing the Federal EPA and U.S. Army Corps of Engineers to review and rescind or revise the rule. In June 2017, the agencies signed a notice of proposed rule to rescind the definition of "waters of the United States" that was adopted in June 2015, and to re-codify the definition of that phrase as it existed immediately prior to that action. This action would effectively retain the status quo until a new rule is adopted by the agencies.

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 and AEP Texas.
- OPCo purchases energy and capacity at auction to serve SSO customers and provides transmission and distribution services for all connected load.
- With the merger of TCC and TNC into AEP Utilities, Inc. to form AEP Texas, the Transmission and Distribution segment now includes certain activities related to the former AEP Utilities, Inc. that had been included in Corporate and Other.

AEP Transmission Holdco

- Development, construction and operation of transmission facilities through investments in AEPTCo. These investments have FERC-approved returns on equity.
- Development, construction and operation of transmission facilities through investments in AEP’s 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.
- Contracted renewable energy investments and management services.

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.

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, Generation Deferrals and Amortization of Generation Deferrals as presented in the Registrants statements of income as applicable. Under the various state utility rate making processes, these expenses are generally reimbursable directly from and billed to customers. As a result, they do not typically impact Operating Income or Earnings Attributable to AEP Common Shareholders. Management believes that Gross Margin provides a useful measure for investors and other financial statement users to analyze AEP's financial performance in that it excludes the effect on Total Revenues caused by volatility in these expenses. Operating income, which is presented in accordance with GAAP in AEP's statements of income, 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 following table presents Earnings (Loss) Attributable to AEP Common Shareholders by segment:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Vertically Integrated Utilities	$286.3	$342.3	$626.6	$829.3
Transmission and Distribution Utilities	144.0	155.7	374.3	387.8
AEP Transmission Holdco	75.5	69.0	275.7	207.5
Generation & Marketing	33.7	(1,369.2)	246.3	(1,248.8)
Corporate and Other	5.2	36.4	(11.0)	61.7
Earnings (Loss) Attributable to AEP Common Shareholders	$544.7	$(765.8)	$1,511.9	$237.5

AEP CONSOLIDATED

Third Quarter of 2017 Compared to Third Quarter of 2016

Earnings (Loss) Attributable to AEP Common Shareholders increased from a loss of $766 million in 2016 to income of $545 million in 2017 primarily due to:

- An increase due to the impairment of certain merchant generation assets in 2016.
- An increase in transmission investment primarily at AEP Transmission Holdco which resulted in higher revenues and income.

These increases were partially offset by:

- A decrease in generation revenues associated with the sale of certain merchant generation assets.
- A decrease in weather-related usage.
- The prior year reversal of income tax expense for an unrealized capital loss valuation allowance. AEP effectively settled a 2011 audit issue with the IRS resulting in a change in the valuation allowance.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Earnings Attributable to AEP Common Shareholders increased from income of $238 million in 2016 to income of $1.5 billion in 2017 primarily due to:

- An increase due to the impairment of certain merchant generation assets in 2016.
- An increase due to the current year gain on the sale of certain merchant generation assets.
- An increase in transmission investment primarily at AEP Transmission Holdco which resulted in higher revenues and income.
- Favorable rate proceedings in AEP’s various jurisdictions.

These increases were partially offset by:

- A decrease in generation revenues associated with the sale of certain merchant generation assets.
- A decrease in weather-related usage.
- A decrease in weather-normalized sales.
- A decrease in FERC wholesale municipal and cooperative revenues.
-

The prior year reversal of income tax expense for an unrealized capital loss valuation allowance. AEP effectively settled a 2011 audit issue with the IRS resulting in a change in the valuation allowance.

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

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
	(in millions)			
Revenues	$2,482.2	$2,556.3	$6,893.1	$6,927.8
Fuel and Purchased Electricity	868.6	858.3	2,368.9	2,299.8
Gross Margin	1,613.6	1,698.0	4,524.2	4,628.0
Other Operation and Maintenance	659.1	673.0	2,024.5	1,926.9
Asset Impairments and Other Related Charges	—	10.5	—	10.5
Depreciation and Amortization	288.8	277.7	845.1	815.5
Taxes Other Than Income Taxes	105.7	99.0	306.2	295.0
Operating Income	560.0	637.8	1,348.4	1,580.1
Interest and Investment Income	1.3	0.8	5.4	2.4
Carrying Costs Income	2.1	0.8	11.3	8.1
Allowance for Equity Funds Used During Construction	7.5	10.0	20.0	35.4
Interest Expense	(134.9)	(136.7)	(406.5)	(399.9)
Income Before Income Tax Expense and Equity Earnings (Loss)	436.0	512.7	978.6	1,226.1
Income Tax Expense	139.1	172.0	334.9	398.4
Equity Earnings (Loss) of Unconsolidated Subsidiaries	0.4	2.7	(4.5)	4.9
Net Income	297.3	343.4	639.2	832.6
Net Income Attributable to Noncontrolling Interests	11.0	1.1	12.6	3.3
Earnings Attributable to AEP Common Shareholders	$286.3	$342.3	$626.6	$829.3

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
	(in millions of KWhs)			
Retail:				
Residential	8,488	9,575	23,226	25,373
Commercial	6,701	7,137	18,386	19,207
Industrial	8,839	8,655	25,792	25,576
Miscellaneous	603	634	1,701	1,740
Total Retail	24,631	26,001	69,105	71,896
Wholesale (a)	6,837	6,765	19,262	17,253
Total KWhs	31,468	32,766	88,367	89,149

(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,	
	2017	2016	2017	2016
	(in degree days)			
Eastern Region				
Actual – Heating (a)	—	—	1,266	1,684
Normal – Heating (b)	4	5	1,757	1,775
Actual – Cooling (c)	698	954	1,034	1,306
Normal – Cooling (b)	731	726	1,060	1,058
Western Region				
Actual – Heating (a)	—	—	539	685
Normal – Heating (b)	1	1	926	927
Actual – Cooling (c)	1,281	1,519	2,000	2,262
Normal – Cooling (b)	1,404	1,400	2,124	2,116

(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 2017 Compared to Third Quarter of 2016
Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Earnings Attributable to AEP Common Shareholders from
Vertically Integrated Utilities
(in millions)

Third Quarter of 2016	$342.3
Changes in Gross Margin:	
Retail Margins	(74.1)
Off-system Sales	(0.8)
Transmission Revenues	(7.6)
Other Revenues	(1.9)
Total Change in Gross Margin	(84.4)
Changes in Expenses and Other:	
Other Operation and Maintenance	13.9
Asset Impairments and Other Related Charges	10.5
Depreciation and Amortization	(11.1)
Taxes Other Than Income Taxes	(6.7)
Interest and Investment Income	0.5
Carrying Costs Income	1.3
Allowance for Equity Funds Used During Construction	(2.5)
Interest Expense	1.8
Total Change in Expenses and Other	7.7
Income Tax Expense	32.9
Equity Earnings (Loss) of Unconsolidated Subsidiary	(2.3)
Net Income Attributable to Noncontrolling Interest	(9.9)
Third Quarter of 2017	$286.3

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 $74 million primarily due to the following:
- An $80 million decrease in weather-related usage in the eastern and western regions.
- The effect of rate proceedings in AEP’s service territories which included:
- A $17 million decrease for PSO primarily due to higher rates implemented in 2016 associated with interim rates.
- A $6 million decrease primarily due to a decrease in rates in West Virginia and Virginia.

For the rate decreases described above, $4 million relate to riders/trackers which have corresponding decreases in expense items below.

These decreases were partially offset by:

- The effect of rate proceedings in AEP’s service territories which included:
- An $11 million increase from rate proceedings in the Indiana service territory.
- An $11 million increase primarily due to rider revenue increases in Louisiana, partially offset in expense items below.

For the rate increases described above, $8 million relate to riders/trackers which have corresponding increases in expense items below.

- An $11 million increase in weather-normalized margins.

- A $4 million increase primarily due to reduced fuel and other variable production costs not recovered through fuel clauses or other trackers.

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- Transmission Revenues decreased $8 million primarily due to the following:
  - A $6 million decrease primarily due to I&M's annual formula rate true-up and reduced net PJM Network Integration Transmission Service revenues resulting from increased affiliated transmission-related charges.
  - A $5 million decrease due to a net favorable accrual for SPP sponsor-funded transmission upgrades in third quarter 2016.

Expenses and Other, Income Tax Expense and Net Income Attributable to Noncontrolling Interest changed between years as follows:

- Other Operation and Maintenance expenses decreased $14 million primarily due to the following:
  - A $15 million decrease in employee-related expenses.
  - A $10 million decrease in PJM and SPP transmission services expense not recovered through riders/trackers.
  - A $6 million decrease in storm expenses, primarily in the APCo region.

  These decreases were partially offset by:
  - A $5 million increase due to the Wind Catcher Project for PSO and SWEPCo.
  - A $5 million increase in nuclear expenses at Cook Plant.
  - A $3 million increase in vegetation management expenses, primarily at PSO and SWEPCo.
- Asset Impairments and Other Related Charges decreased $11 million due to the impairment of I&M's Price River Coal reserves in 2016.
- Depreciation and Amortization expenses increased $11 million primarily due to the following:
  - A $15 million increase primarily due to higher depreciable base.
  - A $6 million increase due to amortization of capitalized software costs.

  These increases were partially offset by:
  - A $9 million decrease primarily related to prior year higher estimated depreciation expense associated with interim rates at PSO.
- Taxes Other Than Income Taxes increased $7 million primarily due to higher property taxes.
- Income Tax Expense decreased $33 million primarily due to a decrease in pretax book income and income tax benefits attributable to SWEPCo's noncontrolling interest in Sabine.
- Net Income Attributable to Noncontrolling Interest increased $10 million primarily due to income tax benefits attributable to SWEPCo's noncontrolling interest in Sabine. This increase is offset by a decrease in Income Tax Expense.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016
Reconciliation of Nine Months Ended September 30, 2016 to
Nine Months Ended September 30, 2017
Earnings Attributable to AEP Common Shareholders from
Vertically Integrated Utilities
(in millions)

Nine Months Ended September 30, 2016	$829.3
Changes in Gross Margin:	
Retail Margins	(123.9)
Off-system Sales	7.4
Transmission Revenues	11.0
Other Revenues	1.7
Total Change in Gross Margin	(103.8)
Changes in Expenses and Other:	
Other Operation and Maintenance	(97.6)
Asset Impairments and Other Related Charges	10.5
Depreciation and Amortization	(29.6)
Taxes Other Than Income Taxes	(11.2)
Interest and Investment Income	3.0
Carrying Costs Income	3.2
Allowance for Equity Funds Used During Construction	(15.4)
Interest Expense	(6.6)
Total Change in Expenses and Other	(143.7)
Income Tax Expense	63.5
Equity Earnings (Loss) of Unconsolidated Subsidiary	(9.4)
Net Income Attributable to Noncontrolling Interest	(9.3)
Nine Months Ended September 30, 2017	$626.6

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 $124 million primarily due to the following:
- A $164 million decrease in weather-related usage in the eastern and western regions.
- A $42 million decrease in FERC generation wholesale municipal and cooperative revenues primarily due to an annual formula rate true-up and adjustments at I&M and SWEPCo.
- The effect of rate proceedings in AEP’s service territories which included:
- A $14 million decrease primarily due to prior year recognition of deferred billing in West Virginia as approved by the WVPSC.
- A $9 million net decrease for PSO primarily due to revenue decreases associated with interim base rates implemented in 2016.

For the rate decreases described above, $1 million relate to riders/trackers which have corresponding decreases in expense items below.

- A $5 million decrease in weather-normalized margins.

These decreases were partially offset by:

- The effect of rate proceedings in AEP’s service territories which included:
- A $42 million increase from rate proceedings in the Indiana service territory.
- A $33 million increase due to rider revenue increases in Louisiana, Texas and Arkansas, partially offset in expense items below.
- A $6 million increase for KGPCo due to revenue increases from rate riders/trackers.

For the rate increases described above, $37 million relate to riders/trackers which have corresponding increases in expense items below.

- A $19 million increase primarily due to reduced fuel and other variable production costs not recovered through fuel clauses or other trackers.
- Margins from Off-system Sales increased $7 million primarily due to higher market prices.
- Transmission Revenues increased $11 million primarily due the following:
- A $35 million increase primarily due to increases in formula rates driven by continued investment in transmission assets. This increase is partially offset in Other Operation and Maintenance expenses below.

These increases were partially offset by:

- A $23 million decrease primarily due to I&M's annual formula rate true-up and reduced net PJM Network Integration Transmission Service revenues resulting from increased affiliated transmission-related charges.
- A $5 million net decrease due to a net favorable accrual for SPP sponsor-funded transmission upgrades in third quarter 2016.

Expenses and Other, Income Tax Expense, Equity Earnings (Loss) of Unconsolidated Subsidiary and Net Income Attributable to Noncontrolling Interest changed between years as follows:

- Other Operation and Maintenance expenses increased $98 million primarily due to the following:
- A $103 million increase in recoverable expenses, primarily PJM expenses and energy efficiency expenses fully recovered in rate recovery riders/trackers within Gross Margin above.
- A $22 million increase in vegetation management expenses, primarily at PSO and I&M.
- A $6 million increase due to a favorable land sale in 2016 in the APCo region.

These increases were partially offset by:

- A $27 million decrease in employee-related expenses.
- Asset Impairments and Other Related Charges decreased $11 million primarily due to the impairment of I&M's Price River Coal reserves in 2016.
- Depreciation and Amortization expenses increased $30 million primarily due to the following:
- A $46 million increase primarily due to higher depreciable base.
- A $15 million increase due to amortization of capitalized software costs.

These increases were partially offset by:

- A $24 million decrease primarily related to prior year higher estimated depreciation expense associated with interim rates at PSO.
- Taxes Other Than Income Taxes increased $11 million primarily due to higher property taxes.
- Allowance for Equity Funds Used During Construction decreased $15 million primarily due to completed environmental projects.
- Interest Expense increased $7 million primarily due to the following:
- A $7 million increase due to lower AFUDC borrowed funds resulting from completed environmental projects.
- A $7 million increase primarily due to higher long-term debt balances at I&M.

These increases were partially offset by:

- A $4 million decrease primarily due to the deferral of the debt component of carrying charges on environmental control costs at PSO.
- Income Tax Expense decreased $64 million primarily due to a decrease in pretax book income and income tax benefits attributable to SWEPCo's noncontrolling interest in Sabine, partially offset by the recording of favorable state and federal income tax adjustments in 2016.
- Equity Earnings (Loss) of Unconsolidated Subsidiary decreased $9 million primarily due to a prior period income tax adjustment for DHLC, a SWEPCo unconsolidated subsidiary.
- Net Income Attributable to Noncontrolling Interest increased $9 million primarily due to income tax benefits attributable to SWEPCo's noncontrolling interest in Sabine. This increase is offset by a decrease in Income Tax Expense.

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TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
	(in millions)			
Revenues	$1,173.3	$1,275.6	$3,313.2	$3,468.5
Purchased Electricity	215.7	253.6	626.0	662.2
Amortization of Generation Deferrals	58.7	66.1	172.9	173.0
Gross Margin	898.9	955.9	2,514.3	2,633.3
Other Operation and Maintenance	303.2	358.2	882.5	1,009.5
Depreciation and Amortization	182.3	181.4	502.4	505.0
Taxes Other Than Income Taxes	133.6	132.0	387.1	373.0
Operating Income	279.8	284.3	742.3	745.8
Interest and Investment Income	1.2	1.5	5.6	5.5
Carrying Costs Income	0.5	0.9	3.0	4.0
Allowance for Equity Funds Used During Construction	0.9	2.2	6.3	10.6
Interest Expense	(61.0)	(63.2)	(182.5)	(196.0)
Income Before Income Tax Expense	221.4	225.7	574.7	569.9
Income Tax Expense	77.4	70.0	200.4	182.1
Net Income	144.0	155.7	374.3	387.8
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$144.0	$155.7	$374.3	$387.8

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
	(in millions of KWhs)			
Retail:				
Residential	7,511	8,325	19,361	20,575
Commercial	6,941	7,287	19,184	19,676
Industrial	5,575	5,518	16,992	16,522
Miscellaneous	185	187	516	528
Total Retail (a)	20,212	21,317	56,053	57,301
Wholesale (b)	585	654	1,749	1,389
Total KWhs	20,797	21,971	57,802	58,690

(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,	
	2017	2016	2017	2016
	(in degree days)			
Eastern Region				
Actual – Heating (a)	—	—	1,500	1,929
Normal – Heating (b)	6	7	2,091	2,110
Actual – Cooling (c)	642	900	957	1,209
Normal – Cooling (b)	670	664	960	956
Western Region				
Actual – Heating (a)	—	—	103	123
Normal – Heating (b)	—	—	199	198
Actual – Cooling (d)	1,393	1,534	2,640	2,619
Normal – Cooling (b)	1,364	1,358	2,396	2,384

(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 2017 Compared to Third Quarter of 2016
Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Earnings Attributable to AEP Common Shareholders from
Transmission and Distribution Utilities
(in millions)

Third Quarter of 2016	$155.7
Changes in Gross Margin:	
Retail Margins	(58.7)
Off-system Sales	(11.6)
Transmission Revenues	7.6
Other Revenues	5.7
Total Change in Gross Margin	(57.0)
Changes in Expenses and Other:	
Other Operation and Maintenance	55.0
Depreciation and Amortization	(0.9)
Taxes Other Than Income Taxes	(1.6)
Interest and Investment Income	(0.3)
Carrying Costs Income	(0.4)
Allowance for Equity Funds Used During Construction	(1.3)
Interest Expense	2.2
Total Change in Expenses and Other	52.7
Income Tax Expense	(7.4)
Third Quarter of 2017	$144.0

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

- Retail Margins decreased $59 million primarily due to the following:
  - A $52 million decrease in Ohio revenues associated with the Universal Service Fund (USF) surcharge rate decrease. This decrease was offset by a corresponding decrease in Other Operating and Maintenance expenses below.
  - An $18 million net decrease in recovery of equity carrying charges related to the Ohio Phase-In Recovery Rider (PIRR), net of associated amortizations.
  - An $8 million decrease in revenues associated with smart grid riders in Ohio. This decrease was offset in expense items below.
  - A $7 million decrease in weather-related usage in Texas.
  - A $5 million decrease in state excise taxes due to a decrease in metered KWh in Ohio. This decrease was offset by a corresponding decrease in Taxes Other Than Income Taxes below.

  These decreases were partially offset by:
  - A $14 million increase in AEP Texas revenues associated with the Distribution Cost Recovery Factor revenue rider.
  - A $12 million favorable impact in Ohio due to the recovery of losses from a power contract with OVEC. The PUCO approved a PPA rider beginning in January 2017 to recover any net margin related to the deferral of OVEC losses starting in June 2016. This increase was offset by a corresponding decrease in Margins from Off-System Sales below.
- Margins from Off-system Sales decreased $12 million due to current year losses from a power contract with OVEC which is deferred in Retail Margins above as a result of the OVEC PPA rider beginning in January 2017.

- Transmission Revenues increased $8 million primarily due to recovery of increased transmission investment in ERCOT.
- Other Revenues increased $6 million primarily due to an increase in Texas securitization revenue, offset in other expense items below.

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

- Other Operation and Maintenance expenses decreased $55 million primarily due to the following:
  - A $52 million decrease in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This decrease was offset by a corresponding decrease in Retail Margins above.
  - A $5 million decrease in employee-related expenses.
  - A $3 million decrease in recoverable smart grid expenses in Ohio. This decrease was offset in Retail Margins above.

  These decreases were partially offset by:
  - A $6 million increase in storm expenses, primarily in the Texas region.
- Depreciation and Amortization expenses increased $1 million primarily due to the following:
  - An $11 million increase primarily due to securitization amortizations related to transition funding, offset in Other Revenues above.
  - A $2 million increase due to amortization of capitalized software costs.

  These increases were partially offset by:
  - A $5 million decrease in recoverable DIR depreciation expense in Ohio.
  - A $4 million decrease in amortization expenses for the collection of carrying costs on Ohio deferred capacity charges beginning June 2015.
  - A $4 million decrease in recoverable smart grid rider depreciation expenses in Ohio. This decrease was offset in Retail Margins above.
- Taxes Other Than Income Taxes increased $2 million primarily due to the following:
  - A $7 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.

  This increase was partially offset by:
  - A $5 million decrease in state excise taxes due to a decrease in metered KWh in Ohio.
- Interest Expense decreased $2 million primarily due to a decrease in the Texas securitization transition assets as a result of the final maturity of the first Texas securitization bond. This decrease was offset by a corresponding decrease in Other Revenues above.
- Income Tax Expense increased $7 million primarily due to the recording of favorable federal income tax adjustments in 2016 and other book/tax differences which are accounted for on a flow-through basis.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Reconciliation of Nine Months Ended September 30, 2016 to
Nine Months Ended September 30, 2017
Earnings Attributable to AEP Common Shareholders from
Transmission and Distribution Utilities
(in millions)

Nine Months Ended September 30, 2016	$387.8
Changes in Gross Margin:	
Retail Margins	(123.0)
Off-system Sales	(26.8)
Transmission Revenues	24.2
Other Revenues	6.6
Total Change in Gross Margin	(119.0)
Changes in Expenses and Other:	
Other Operation and Maintenance	127.0
Depreciation and Amortization	2.6
Taxes Other Than Income Taxes	(14.1)
Interest and Investment Income	0.1
Carrying Costs Income	(1.0)
Allowance for Equity Funds Used During Construction	(4.3)
Interest Expense	13.5
Total Change in Expenses and Other	123.8
Income Tax Expense	(18.3)
Nine Months Ended September 30, 2017	$374.3

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

- Retail Margins decreased $123 million primarily due to the following:
- A $140 million decrease in Ohio revenues associated with the USF surcharge rate decrease. This decrease was offset by a corresponding decrease in Other Operating and Maintenance expenses below.
- A $14 million decrease in weather-normalized margins, primarily in the residential class.
- A $21 million decrease due to a prior year reversal of a regulatory provision resulting from a favorable court decision in Ohio.
- A $13 million decrease in revenues associated with smart grid riders in Ohio. This decrease was offset in expense items below.
- A $9 million net decrease in recovery of equity carrying charges related to the PIRR, net of associated amortizations.
- A $7 million decrease in state excise taxes due to a decrease in metered KWh in Ohio. This decrease was offset by a corresponding decrease in Taxes Other Than Income Taxes.

These decreases were partially offset by:

- A $46 million favorable impact in Ohio due to the recovery of losses from a power contract with OVEC. The PUCO approved a PPA rider beginning in January 2017 to recover any net margin related to the deferral of OVEC losses starting in June 2016. This increase was offset by a corresponding decrease in Margins from Off-System Sales below.
- A $40 million increase in AEP Texas revenues associated with the Distribution Cost Recovery Factor revenue rider.

- A $6 million increase in rider revenues associated with the DIR. This increase is partially offset in other expense items below.

- Margins from Off-system Sales decreased $27 million primarily due to the following:
- A $46 million decrease in Ohio due to current year losses from a power contract with OVEC, which is deferred in Retail Margins above as a result of the OVEC PPA rider beginning in January 2017.

This decrease was partially offset by:

- An $18 million increase in Ohio primarily due to the impact of prior year losses from a power contract with OVEC which was not included in the OVEC PPA rider.
- Transmission Revenues increased $24 million primarily due to recovery of increased transmission investment in ERCOT.
- Other Revenues increased $7 million primarily due to an increase in Texas securitization revenue, offset in other expense items below.

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

- Other Operation and Maintenance expenses decreased $127 million primarily due to the following:
- A $140 million decrease in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This decrease was offset by a corresponding decrease in Retail Margins above.
- A $10 million decrease in employee-related expenses.

These decreases were partially offset by:

- A $12 million increase in PJM expenses related to the annual formula rate true-up that will be recovered in future periods.
- A $6 million increase in storm expenses, primarily in the Texas region.
- A $5 million increase in vegetation management expenses.
- Depreciation and Amortization expenses decreased $3 million primarily due to the following:
- An $11 million decrease in amortization expenses for the collection of carrying costs on Ohio deferred capacity charges beginning June 2015.
- An $8 million decrease due to recoveries of transmission cost rider carrying costs in Ohio. This decrease was partially offset in Retail Margins above.
- A $7 million decrease in recoverable DIR depreciation expense in Ohio.
- A $5 million decrease in recoverable smart grid rider depreciation expenses in Ohio. This decrease was offset in Retail Margins above.

These decreases were partially offset by:

- A $16 million increase due to securitization amortizations related to transition funding, offset in Other Revenues above.
- A $9 million increase in depreciation expense primarily due to an increase in depreciable base of transmission and distribution assets.
- A $6 million increase due to amortization of capitalized software costs.
- Taxes Other Than Income Taxes increased $14 million primarily due to the following:
- A $20 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.

This increase were partially offset by:

- A $7 million decrease in state excise taxes due to a decrease in metered KWh in Ohio.
- Allowance for Equity Funds Used During Construction decreased $4 million primarily due to larger short-term debt balances.
- Interest Expense decreased $14 million primarily due to the following:
- A $9 million decrease due to the maturity of a senior unsecured note in June 2016 in Ohio.
- A $7 million decrease in the Texas 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.
-

Income Tax Expense increased $18 million primarily due to the recording of favorable state and federal income tax adjustments in 2016 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, 2017	2016	Nine Months Ended September 30, 2017	2016
	(in millions)			
Transmission Revenues	$178.5	$132.4	$581.9	$382.7
Other Operation and Maintenance	23.1	12.2	54.5	32.7
Depreciation and Amortization	26.1	17.1	74.7	48.4
Taxes Other Than Income Taxes	28.6	22.7	85.0	65.7
Operating Income	100.7	80.4	367.7	235.9
Interest and Investment Income	0.1	—	0.5	—
Carrying Costs Expense	—	—	(0.1)	(0.2)
Allowance for Equity Funds Used During Construction	11.6	13.5	35.9	39.8
Interest Expense	(17.9)	(12.2)	(52.3)	(35.4)
Income Before Income Tax Expense and Equity Earnings	94.5	81.7	351.7	240.1
Income Tax Expense	38.6	35.2	142.1	103.2
Equity Earnings of Unconsolidated Subsidiaries	20.6	23.0	68.7	72.6
Net Income	76.5	69.5	278.3	209.5
Net Income Attributable to Noncontrolling Interests	1.0	0.5	2.6	2.0
Earnings Attributable to AEP Common Shareholders	$75.5	$69.0	$275.7	$207.5

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	September 30, 2017	2016
	(in millions)	
Plant in Service	$5,001.4	$3,330.5
CWIP	1,392.8	1,565.8
Accumulated Depreciation	156.6	88.1
Total Transmission Property, Net	$6,237.6	$4,808.2

Third Quarter of 2017 Compared to Third Quarter of 2016

Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Third Quarter of 2016	$69.0
Changes in Transmission Revenues:	
Transmission Revenues	46.1
Total Change in Transmission Revenues	46.1
Changes in Expenses and Other:	
Other Operation and Maintenance	(10.9)
Depreciation and Amortization	(9.0)
Taxes Other Than Income Taxes	(5.9)
Interest and Investment Income	0.1
Allowance for Equity Funds Used During Construction	(1.9)
Interest Expense	(5.7)
Total Change in Expenses and Other	(33.3)
Income Tax Expense	(3.4)
Equity Earnings	(2.4)
Net Income Attributable to Noncontrolling Interests	(0.5)
Third Quarter of 2017	$75.5

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 $46 million primarily due to an increase in formula rates driven by continued investment in transmission assets.

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

- Other Operation and Maintenance expenses increased $11 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $9 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.
- Interest Expense increased $6 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $3 million primarily due to an increase in pretax book income.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Reconciliation of Nine Months Ended September 30, 2016 to Nine Months Ended September 30, 2017
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Nine Months Ended September 30, 2016	$207.5
Changes in Transmission Revenues:	
Transmission Revenues	199.2
Total Change in Transmission Revenues	199.2
Changes in Expenses and Other:	
Other Operation and Maintenance	(21.8)
Depreciation and Amortization	(26.3)
Taxes Other Than Income Taxes	(19.3)
Interest and Investment Income	0.5
Carrying Costs Expense	0.1
Allowance for Equity Funds Used During Construction	(3.9)
Interest Expense	(16.9)
Total Change in Expenses and Other	(87.6)
Income Tax Expense	(38.9)
Equity Earnings	(3.9)
Net Income Attributable to Noncontrolling Interests	(0.6)
Nine Months Ended September 30, 2017	$275.7

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 $199 million primarily due to the current year favorable impact of the modification of the PJM OATT formula rates combined with an increase driven by continued investment in transmission assets.

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

- Other Operation and Maintenance expenses increased $22 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $26 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $19 million primarily due to increased property taxes as a result of additional transmission investment.
- Allowance for Equity Funds Used During Construction decreased $4 million primarily due to the FERC transmission complaint and an increase in the amount of short-term debt, offset by an increase in the CWIP balance.
- Interest Expense increased $17 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $39 million primarily due to an increase in pretax book income.
- Equity Earnings decreased $4 million primarily due to lower earnings at ETT resulting from increased property taxes, depreciation expense, and decreased AFUDC, partially offset by increased revenues. The revenue increase is primarily due to interim rate increases in the third quarter of 2016 and higher loads, partially offset by an ETT rate reduction that went into effect in March 2017.

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GENERATION & MARKETING

Generation & Marketing	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
	(in millions)			
Revenues	$465.5	$859.4	$1,467.5	$2,291.2
Fuel, Purchased Electricity and Other	354.6	567.4	1,062.7	1,490.6
Gross Margin	110.9	292.0	404.8	800.6
Other Operation and Maintenance	56.5	95.8	211.4	290.2
Asset Impairments and Other Related Charges	(2.5)	2,254.4	10.6	2,254.4
Gain on Sale of Merchant Generation Assets	—	—	(226.4)	—
Depreciation and Amortization	6.2	50.5	17.5	149.8
Taxes Other Than Income Taxes	3.2	8.7	8.9	29.0
Operating Income (Loss)	47.5	(2,117.4)	382.8	(1,922.8)
Interest and Investment Income	2.7	0.3	7.9	1.2
Interest Expense	(4.0)	(9.5)	(14.7)	(27.1)
Income (Loss) Before Income Tax Expense	46.2	(2,126.6)	376.0	(1,948.7)
Income Tax Expense (Credit)	12.5	(757.4)	129.7	(699.9)
Net Income (Loss)	33.7	(1,369.2)	246.3	(1,248.8)
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings (Loss) Attributable to AEP Common Shareholders	$33.7	$(1,369.2)	$246.3	$(1,248.8)

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
	(in millions of MWhs)			
Fuel Type:				
Coal	2	8	10	19
Natural Gas	—	4	2	11
Total MWhs	2	12	12	30

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Third Quarter of 2017 Compared to Third Quarter of 2016
Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Third Quarter of 2016	$(1,369.2)
Changes in Gross Margin:	
Generation	(175.4)
Retail, Trading and Marketing	(10.1)
Other	4.4
Total Change in Gross Margin	(181.1)
Changes in Expenses and Other:	
Other Operation and Maintenance	39.3
Asset Impairments and Other Related Charges	2,256.9
Depreciation and Amortization	44.3
Taxes Other Than Income Taxes	5.5
Interest and Investment Income	2.4
Interest Expense	5.5
Total Change in Expenses and Other	2,353.9
Income Tax Expense	(769.9)
Third Quarter of 2017	$33.7

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 $175 million primarily due to the reduction of revenues associated with the sale of certain merchant generation assets.
- Retail, Trading and Marketing decreased $10 million due to lower retail margins in 2017 partially offset by favorable wholesale trading and marketing performance in 2017.
- Other increased $4 million primarily due to renewable projects placed in service.

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

- Other Operation and Maintenance expenses decreased $39 million primarily due to decreased plant expenses as a result of the sale of certain merchant generation assets.
- Asset Impairments and Other Related Charges decreased $2.3 billion due to the asset impairment of certain merchant generation assets in 2016.
- Depreciation and Amortization expenses decreased $44 million primarily due to the sale and impairment of certain merchant generation assets.
- Taxes Other Than Income Taxes decreased $6 million primarily due to the sale of certain merchant generation assets.
- Interest Expense decreased $6 million primarily due to reduced debt as a result of the sale of certain merchant generation assets.

- Income Tax Expense increased $770 million primarily due to an increase in pretax book income resulting primarily from the impairment of certain merchant generation assets in 2016.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016
Reconciliation of Nine Months Ended September 30, 2016
to Nine Months Ended September 30, 2017
Earnings Attributable to AEP Common Shareholders from
Generation & Marketing
(in millions)

Nine Months Ended September 30, 2016	$(1,248.8)
Changes in Gross Margin:	
Generation	(376.2)
Retail, Trading and Marketing	(33.6)
Other	14.0
Total Change in Gross Margin	(395.8)
Changes in Expenses and Other:	
Other Operation and Maintenance	78.8
Asset Impairments and Other Related Charges	2,243.8
Gain on Sale of Merchant Generation Assets	226.4
Depreciation and Amortization	132.3
Taxes Other Than Income Taxes	20.1
Interest and Investment Income	6.7
Interest Expense	12.4
Total Change in Expenses and Other	2,720.5
Income Tax Expense	(829.6)
Nine Months Ended September 30, 2017	$246.3

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 $376 million primarily due to the reduction of revenues associated with the sale of certain merchant generation assets.
- Retail, Trading and Marketing decreased $34 million primarily due to lower margins in 2017 combined with the impact of favorable wholesale trading and marketing performance in 2016.
- Other increased $14 million primarily due to renewable projects placed in service.

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

- Other Operation and Maintenance expenses decreased $79 million primarily due to decreased plant expenses as a result of the sale of certain merchant generation assets.
- Asset Impairments and Other Related Charges decreased $2.2 billion due to the asset impairment of certain merchant generation assets in 2016.
- Gain on Sale of Merchant Generation Assets increased $226 million due to the sale of certain merchant generation assets.
- Depreciation and Amortization expenses decreased $132 million primarily due to the sale and impairment of certain merchant generation assets.

- Taxes Other Than Income Taxes decreased $20 million primarily due to the sale of certain merchant generation assets.
- Interest and Investment Income increased $7 million primarily due to increased cash invested as a result of the sale of certain merchant generation assets.
- Interest Expense decreased $12 million primarily due to reduced debt as a result of the sale of certain merchant generation assets.
- Income Tax Expense increased $830 million primarily due to an increase in pretax book income and state income taxes resulting primarily from the impairment of certain merchant generation assets in 2016.

CORPORATE AND OTHER

Third Quarter of 2017 Compared to Third Quarter of 2016

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from $36 million in 2016 to $5 million in 2017 primarily due to the prior year reversal of a capital loss valuation allowance 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, partially offset by the gain recognized on the sale of a cost-based investment in the third quarter of 2017.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from income of $62 million in 2016 to a loss of $11 million in 2017 primarily due to the prior year reversal of capital loss valuation allowances related to effectively settling 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, partially offset by the gain recognized on the sale of a cost-based investment in the third quarter of 2017.

AEP SYSTEM INCOME TAXES

Third Quarter of 2017 Compared to Third Quarter of 2016

Income Tax Expense increased $799 million primarily due to an increase in pretax book income driven by the impairment of certain merchant generation assets in the third quarter of 2016. The increase in Income Tax Expense is also due to the third quarter of 2016 reversal of a $66 million capital loss valuation allowance related to the pending sale of certain merchant generation assets as well as prior year tax return adjustments related to the disposition of AEP’s commercial barging operations.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Income Tax Expense increased $932 million primarily due to an increase in pretax book income driven by the impairment of certain merchant generation assets in the third quarter of 2016. The increase in Income Tax Expense is also due to the prior year reversal of a $56 million unrealized capital loss valuation allowance where AEP effectively settled a 2011 audit issue with the IRS, the prior year reversal of a $66 million capital loss valuation allowance related to the pending sale of certain merchant generation assets as well as prior year 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, 2017		December 31, 2016		
	(dollars in millions)				
Long-term Debt, including amounts due within one year	$20,721.7	51.9 %	$20,391.2	(a)	51.6 %
Short-term Debt	1,059.3	2.7	1,713.0		4.3
Total Debt	21,781.0	54.6	22,104.2	(a)	55.9
AEP Common Equity	18,069.1	45.3	17,397.0		44.0
Noncontrolling Interests	36.4	0.1	23.1		0.1
Total Debt and Equity Capitalization	$39,886.5	100.0%	$39,524.3		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 decreased from 55.9% as of December 31, 2016 to 54.6% as of September 30, 2017 primarily due to a decrease in short-term debt due to the use of proceeds from the sale of Merchant Generation Assets to pay down debt. See “Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)” section of Note 6 for additional information.

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, 2017, AEP had a $3 billion revolving credit facility commitment to support its operations. In May 2017, the $500 million revolving credit facility due in June 2018 was terminated. 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, 2017, 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
Total	3,000.0	
Cash and Cash Equivalents	343.9	
Total Liquidity Sources	3,343.9	
Less: AEP Commercial Paper Outstanding	295.0	

Net Available Liquidity	$ 3,048.9

AEP has a $3 billion revolving credit facility to support its commercial paper program.

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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 2017 was $1.6 billion. The weighted-average interest rate for AEP's commercial paper during 2017 was 1.19%.

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 five uncommitted facilities totaling $445 million. In August 2017, AEP executed a $75 million uncommitted letter of credit facility due in August 2018. As of September 30, 2017, the maximum future payment for letters of credit issued under the uncommitted facilities was $123 million with maturities ranging from October 2017 to September 2018.

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 2019.

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, 2017, this contractually-defined percentage was 52.4%. 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 facility does not permit the lenders to refuse a draw on the 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 $0.62 per share in October 2017. 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,	
	2017	2016
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$210.5	$176.4
Net Cash Flows from Continuing Operating Activities	3,124.2	3,421.0
Net Cash Flows Used for Continuing Investing Activities	(1,676.6)	(3,428.7)
Net Cash Flows from (Used for) Continuing Financing Activities	(1,314.2)	46.0
Net Cash Flows Used for Discontinued Operations	—	(2.5)
Net Increase in Cash and Cash Equivalents	133.4	35.8
Cash and Cash Equivalents at End of Period	$343.9	$212.2

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,	
	2017	2016
	(in millions)	
Income from Continuing Operations	$1,527.1	$245.3
Depreciation and Amortization	1,485.9	1,550.2
Deferred Income Taxes	740.9	(47.0)
Asset Impairments and Other Related Charges	10.6	2,264.9
Gain on Sale of Merchant Generation Assets	(226.4)	—
Provision for Refund – Global Settlement, Net	(93.3)	—
Accrued Taxes, Net	(310.1)	(393.0)
Other	(10.5)	(199.4)
Net Cash Flows from Continuing Operating Activities	$3,124.2	$3,421.0

Net Cash Flows from Continuing Operating Activities were $3.1 billion in 2017 consisting primarily of Income from Continuing Operations of $1.5 billion and $1.5 billion of noncash Depreciation and Amortization. In addition, AEP recorded a gain of $226 million on the sale of certain merchant generation assets. AEP also recorded asset impairments of $11 million. See Note 6 - Impairment, Disposition and Assets and Liabilities Held for Sale for a complete discussion of this sale and these impairments. Deferred and Accrued Taxes changed primarily due to the income tax impacts associated with the sale of certain merchant generation assets and the receipt of a tax refund related to the U.K. Windfall Tax. AEP refunded $93 million to customers as part of the Ohio Global Settlement reached in 2016. 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 $3.4 billion in 2016 consisting primarily of Income from Continuing Operations 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 - Impairment, Disposition and 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.

Investing Activities

	Nine Months Ended September 30,	
	2017	2016
	(in millions)	
Construction Expenditures	$(3,778.2)	$(3,387.0)
Acquisitions of Nuclear Fuel	(73.2)	(127.6)
Proceeds from Sale of Merchant Generation Assets	2,159.6	—
Other	15.2	85.9
Net Cash Flows Used for Continuing Investing Activities	$(1,676.6)	$(3,428.7)

Net Cash Flows Used for Continuing Investing Activities were $1.7 billion in 2017 primarily due to Construction Expenditures for environmental, distribution and transmission investments, partially offset by the proceeds received from the sale of certain merchant generation assets. See Note 6 - Impairment, Disposition and Assets and Liabilities Held for Sale for a complete discussion of this sale.

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.

Financing Activities

	Nine Months Ended September 30,	
	2017	2016
	(in millions)	
Issuance of Common Stock, Net	$—	$34.2
Issuance/Retirement of Debt, Net	(338.2)	930.3
Make Whole Premium on Extinguishment of Long-term Debt	(46.1)	—
Dividends Paid on Common Stock	(875.0)	(829.8)
Other	(54.9)	(88.7)
Net Cash Flows from (Used for) Continuing Financing Activities	$(1,314.2)	$46.0

Net Cash Flows Used for Continuing Financing Activities in 2017 were $1.3 billion. AEP's net debt retirements were $338 million. The net retirements include retirements of $978 million of senior unsecured notes, $356 million of pollution control bonds, $258 million of securitization bonds, $835 million of other debt notes and repayments of $654 million of short term debt offset by issuances of $2.3 billion of senior unsecured notes, $242 million of pollution control bonds and $254 million of other debt notes. AEP also paid $46 million for a make whole premium on the early extinguishment of debt related to the sale of certain merchant generation assets. See Note 6 - Impairment, Disposition and Assets and Liabilities Held for Sale for a complete discussion of this sale. AEP paid common stock dividends of $875 million. See Note 12 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

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.

In October 2017, I&M retired $1 million of Notes Payable related to DCC Fuel.

In October 2017, AEP Texas retired $41 million of 5.625% Pollution Control Bonds due in 2017.

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, 2017	December 31, 2016
	(in millions)	
Rockport Plant, Unit 2 Future Minimum Lease Payments	$812.4	$ 886.2
Railcars Maximum Potential Loss from Lease Agreement	16.9	18.4

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 2016 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2016 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in the "Cash Flow" section above.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND 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 2016 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.

ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncements Adopted During 2017

The FASB issued ASU 2015-11 "Simplifying the Measurement of Inventory" 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 adopted ASU 2015-11 prospectively, effective January 1, 2017. There was no impact on results of operations, financial position or cash flows at adoption.

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. Management adopted ASU 2016-09 effective January 1, 2017. As a result of the adoption of this guidance, management made an accounting policy election to recognize the effect of forfeitures in compensation cost when they occur. There was an immaterial impact on results of operations and financial position and no impact on cash flows at adoption.

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. Management continues to analyze the impact of the new revenue standard and related ASUs.

During 2016 and 2017, revenue contract assessments were completed. Material revenue streams were identified within the AEP System and representative contract/transaction types were sampled. Performance obligations identified within each material revenue stream were evaluated to determine whether the obligations were satisfied at a point in time or over time. Contracts determined to be satisfied over time generally qualified for the invoicing practical expedient since the invoiced amounts reasonably represented the value to customers of performance obligations fulfilled to date. Based upon the completed assessments, management does not expect a material impact to the timing of revenue recognized or net income and plans to elect the modified retrospective transition approach upon adoption.

The evaluation of revenue streams, new contracts and the new revenue standard's disclosure requirements continues during the fourth quarter of 2017, in particular with respect to various ongoing industry implementation issues. Management will continue to analyze the related impacts to revenue recognition and monitor any new industry implementation issues that arise. Further, given industry conclusions related to implementation issues, including contributions in aid of construction and collectability, management does not anticipate changes to current accounting systems. Management plans to adopt ASU 2014-09 effective January 1, 2018.

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 sheets 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. Management continues to analyze the impact of the new lease standard. During 2016 and 2017, lease contract assessments were completed. The AEP System lease population was identified and representative lease contracts were sampled. Based upon the completed assessments, management prepared a system gap analysis to outline new disclosure compliance requirements compared to current system capabilities. Multiple lease system options were also evaluated. Management plans to elect certain of the following practical expedients upon adoption:

Practical Expedient	Description
Overall Expedients (for leases commenced prior to adoption date and must be adopted as a package)	Do not need to reassess whether any expired or existing contracts are/or contain leases, do not need to reassess the lease classification for any expired or existing leases and do not need to reassess initial direct costs for any existing leases.
Lease and Non-lease Components (elect by class of underlying asset)	Elect as an accounting policy to not separate non-lease components from lease components and instead account for each lease and associated non-lease component as a single lease component.
Short-term Lease (elect by class of underlying asset)	Elect as an accounting policy to not apply the recognition requirements to short-term leases.
Lease term	Elect to use hindsight to determine the lease term.

Evaluation of new lease contracts continues and the process of implementing a compliant lease system solution began in the third quarter of 2017. Management expects the new standard to impact financial position, but not results of operations or cash flows. Management also continues to monitor unresolved industry implementation issues, including items related to pole attachments, easements and right-of-ways, and will analyze the related impacts to lease accounting. Management plans to adopt ASU 2016-02 effective January 1, 2019.

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.

The FASB issued ASU 2016-18 “Restricted Cash” clarifying the treatment of restricted cash on the statements of cash flows. Under the new standard, amounts considered restricted cash will be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts on the statements of cash flows. The new accounting guidance is effective for annual periods beginning after December 15, 2017. Early adoption is permitted in any interim or annual period. The guidance will be applied by means of a retrospective approach. Management is analyzing the impact of the new standard. Management plans to adopt ASU 2016-18 effective for the 2017 Annual Report.

The FASB issued ASU 2017-07 “Compensation - Retirement Benefits” requiring that an employer report the service cost component of pension and postretirement benefits in the same line item or items as other compensation costs. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside of a subtotal of income from operations. In addition, only the service cost component will be eligible for capitalization as applicable following labor. For 2016, AEP's actual non-service cost components were a credit of $66 million, of which approximately 37% was capitalized. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted as of the beginning of an annual period for which financial statements have not been issued or made available for issuance. Management plans to adopt ASU 2017-07 effective January 1, 2018.

The FASB issued ASU 2017-12 “Derivatives and Hedging” amending the recognition and presentation requirements for hedge accounting activities. The objectives are to improve the financial reporting of hedging relationships to better portray the economic results of an entity’s risk management activities in its financial statements and reduce the complexity of applying hedge accounting. Under the new standard, the concept of recognizing hedge ineffectiveness within the statements of income for cash flow hedges, which has historically been immaterial to AEP, will be eliminated. In addition, certain required tabular disclosures relating to fair value and cash flow hedges will be modified. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2018 with early adoption permitted for any interim or annual period after August 2017. Management is analyzing the impact of this new standard, including the possibility of early adoption, and at this time, cannot estimate the impact of adoption on net income.

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. Future pronouncements issued by the FASB 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 power producer and through transactions in wholesale electricity, natural gas and marketing contracts.

Management employs risk management contracts including physical forward 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 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 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, 2016:
MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2017

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
	(in millions)			
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2016	$5.2	$ (118.2)	$ 164.2	$51.2
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(7.0)	3.4	(32.8)	(36.4)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	26.7	26.7
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	10.5	10.5
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	64.9	(23.2)	—	41.7
Total MTM Risk Management Contract Net Assets (Liabilities) as of September 30, 2017	$63.1	$ (138.0)	$ 168.6	93.7
Commodity Cash Flow Hedge Contracts				(75.6)
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				4.2
Fair Value Hedge Contracts				(1.4)
Collateral Deposits				13.5
Total MTM Derivative Contract Net Assets as of September 30, 2017				$34.4

(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 or accounts payable.

See Note 9 – Derivatives and Hedging and Note 10 – Fair Value Measurements for additional information related to risk management contracts. The following tables and discussion provide information on credit risk and market volatility risk.

Credit Risk

Credit risk is mitigated 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 Inc., S&P Global Inc. 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, 2017, credit exposure net of collateral to sub investment grade counterparties was approximately 7.9%, 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, 2017, 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	$619.6	$ 2.2	$ 617.4	3	$ 352.2
Split Rating	5.6	—	5.6	2	5.6
Noninvestment Grade	—	—	—	—	—
No External Ratings:					
Internal Investment Grade	119.2	—	119.2	3	78.7
Internal Noninvestment Grade	75.4	11.5	63.9	3	40.5
Total as of September 30, 2017	$819.8	$ 13.7	$ 806.1		

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, 2017, 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, 2017				Twelve Months Ended December 31, 2016			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$0.2	$0.4	$ 0.1	$0.1	$0.2	$1.1	$ 0.2	$0.1

VaR Model
Non-Trading Portfolio

Nine Months Ended September 30, 2017	Twelve Months Ended December 31, 2016

End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$0.7	$6.5	$ 0.9	$0.3	$5.6	$8.4	$ 1.5	$0.4

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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, 2017 and December 31, 2016, the estimated EaR on AEP's debt portfolio for the following twelve months was $30 million and $29 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
REVENUES				
Vertically Integrated Utilities	$2,453.8	$ 2,538.3	$6,819.3	$ 6,864.6
Transmission and Distribution Utilities	1,149.7	1,245.4	3,242.7	3,398.9
Generation & Marketing	441.5	823.3	1,386.8	2,192.5
Other Revenues	59.7	45.2	165.7	134.0
TOTAL REVENUES	4,104.7	4,652.2	11,614.5	12,590.0
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	707.4	880.1	1,865.3	2,236.1
Purchased Electricity for Resale	718.1	774.0	2,156.9	2,134.6
Other Operation	636.1	771.1	1,842.5	2,150.7
Maintenance	268.0	286.3	859.4	854.4
Asset Impairments and Other Related Charges	(2.5)	2,264.9	10.6	2,264.9
Gain on Sale of Merchant Generation Assets	—	—	(226.4)	—
Depreciation and Amortization	518.5	539.3	1,485.9	1,550.2
Taxes Other Than Income Taxes	272.6	264.4	792.0	767.9
TOTAL EXPENSES	3,118.2	5,780.1	8,786.2	11,958.8
OPERATING INCOME (LOSS)	986.5	(1,127.9)	2,828.3	631.2
Other Income (Expense):				
Interest and Investment Income	2.4	2.0	12.7	6.5
Carrying Costs Income	2.6	1.7	14.2	11.9
Allowance for Equity Funds Used During Construction	20.0	25.6	62.2	86.1
Gain on Sale of Equity Investment	12.4	—	12.4	—
Interest Expense	(223.3)	(225.3)	(668.0)	(667.2)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (CREDIT) AND EQUITY EARNINGS	800.6	(1,323.9)	2,261.8	68.5
Income Tax Expense (Credit)	264.0	(534.5)	797.8	(134.0)
Equity Earnings of Unconsolidated Subsidiaries	20.1	25.2	63.1	42.8
INCOME (LOSS) FROM CONTINUING OPERATIONS	556.7	(764.2)	1,527.1	245.3
LOSS FROM DISCONTINUED OPERATIONS, NET OF TAX	—	—	—	(2.5)
NET INCOME (LOSS)	556.7	(764.2)	1,527.1	242.8
Net Income Attributable to Noncontrolling Interests	12.0	1.6	15.2	5.3

EARNINGS (LOSS) ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 544.7	$ (765.8)	$ 1,511.9	$ 237.5
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	491,840,722	491,697,809	491,781,643	491,422,921
BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS	$ 1.11	$ (1.56)	$ 3.07	$ 0.49
BASIC LOSS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS	—	—	—	(0.01)
TOTAL BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.11	$ (1.56)	$ 3.07	$ 0.48
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	492,986,307	491,813,858	492,428,586	491,596,861
DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS	$ 1.10	$ (1.56)	$ 3.07	$ 0.49
DILUTED LOSS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS	—	—	—	(0.01)
TOTAL DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.10	$ (1.56)	$ 3.07	$ 0.48
CASH DIVIDENDS DECLARED PER SHARE	$ 0.59	$ 0.56	$ 1.77	$ 1.68

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net Income (Loss)	$556.7	$(764.2)	$1,527.1	$242.8
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(8.1) and $(15.4) for the Three Months Ended September 30, 2017 and 2016, Respectively, and $(12.2) and $(11.2) for the Nine Months Ended September 30, 2017 and 2016, Respectively	(15.0)	(28.6)	(22.6)	(20.8)
Securities Available for Sale, Net of Tax of $0.5 and $0.3 for the Three Months Ended September 30, 2017 and 2016, Respectively, and $1.5 and $1 for the Nine Months Ended September 30, 2017 and 2016, Respectively	0.9	0.5	2.7	1.7
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0.1 and $0.1 for the Three Months Ended September 30, 2017 and 2016, Respectively, and $0.4 and $0.2 for the Nine Months Ended September 30, 2017 and 2016, Respectively	0.3	0.2	0.8	0.4
TOTAL OTHER COMPREHENSIVE LOSS	(13.8)	(27.9)	(19.1)	(18.7)
TOTAL COMPREHENSIVE INCOME (LOSS)	542.9	(792.1)	1,508.0	224.1
Total Comprehensive Income Attributable to Noncontrolling Interests	12.0	1.6	15.2	5.3
TOTAL COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$530.9	$(793.7)	$1,492.8	$218.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY - DECEMBER 31, 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
TOTAL EQUITY - DECEMBER 31, 2016	512.0	$3,328.3	$6,332.6	$7,892.4	$ (156.3)	$ 23.1	$17,420.1
Common Stock Dividends				(872.3)		(2.7)	(875.0)
Other Changes in Equity			51.6			0.8	52.4
Net Income				1,511.9		15.2	1,527.1
Other Comprehensive Loss					(19.1)		(19.1)
TOTAL EQUITY - SEPTEMBER 30, 2017	512.0	$3,328.3	$6,384.2	$8,532.0	$ (175.4)	$ 36.4	$18,105.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2017 and December 31, 2016
(in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents	$343.9	$ 210.5
Other Temporary Investments (September 30, 2017 and December 31, 2016 Amounts Include $300.5 and $322.5, Respectively, Related to Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, EIS, Transource Energy and Sabine)	310.7	331.7
Accounts Receivable:		
Customers	522.7	705.1
Accrued Unbilled Revenues	187.3	158.7
Pledged Accounts Receivable – AEP Credit	967.6	972.7
Miscellaneous	99.9	118.1
Allowance for Uncollectible Accounts	(36.6)	(37.9)
Total Accounts Receivable	1,740.9	1,916.7
Fuel	354.2	423.8
Materials and Supplies	562.3	543.5
Risk Management Assets	146.1	94.5
Regulatory Asset for Under-Recovered Fuel Costs	153.5	156.6
Margin Deposits	105.7	79.9
Assets Held for Sale	—	1,951.2
Prepayments and Other Current Assets	350.5	325.5
TOTAL CURRENT ASSETS	4,067.8	6,033.9
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	20,739.3	19,848.9
Transmission	17,785.4	16,658.7
Distribution	19,589.4	18,900.8
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	3,614.1	3,444.3
Construction Work in Progress	3,710.0	3,183.9
Total Property, Plant and Equipment	65,438.2	62,036.6
Accumulated Depreciation and Amortization	17,121.7	16,397.3
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	48,316.5	45,639.3
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,640.0	5,625.5
Securitized Assets	1,287.8	1,486.1
Spent Nuclear Fuel and Decommissioning Trusts	2,433.0	2,256.2
Goodwill	52.5	52.5
Long-term Risk Management Assets	310.4	289.1
Deferred Charges and Other Noncurrent Assets	1,856.9	2,085.1

TOTAL OTHER NONCURRENT ASSETS	11,580.6	11,794.5
TOTAL ASSETS	$63,964.9	$ 63,467.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2017 and December 31, 2016
(dollars in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT LIABILITIES		
Accounts Payable	$ 1,537.0	$ 1,688.5
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	750.0	673.0
Other Short-term Debt	309.3	1,040.0
Total Short-term Debt	1,059.3	1,713.0
Long-term Debt Due Within One Year (September 30, 2017 and December 31, 2016 Amounts Include $393.7 and $427.5, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Sabine)	2,359.3	2,878.0
Risk Management Liabilities	69.4	53.4
Customer Deposits	346.6	343.2
Accrued Taxes	716.5	1,048.0
Accrued Interest	260.3	227.2
Regulatory Liability for Over-Recovered Fuel Costs	19.7	8.0
Liabilities Held for Sale	—	235.9
Other Current Liabilities	953.9	1,302.8
TOTAL CURRENT LIABILITIES	7,322.0	9,498.0
NONCURRENT LIABILITIES		
Long-term Debt (September 30, 2017 and December 31, 2016 Amounts Include $1421.5 and $1,737.5, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy, and Sabine)	18,362.4	17,378.4
Long-term Risk Management Liabilities	352.7	316.2
Deferred Income Taxes	12,628.2	11,884.4
Regulatory Liabilities and Deferred Investment Tax Credits	3,959.6	3,751.3
Asset Retirement Obligations	1,919.3	1,830.6
Employee Benefits and Pension Obligations	468.9	614.1
Deferred Credits and Other Noncurrent Liabilities	837.0	774.6
TOTAL NONCURRENT LIABILITIES	38,528.1	36,549.6
TOTAL LIABILITIES	45,850.1	46,047.6

Rate Matters (Note 4)
Commitments and Contingencies (Note 5)

MEZZANINE EQUITY

Contingently Redeemable Performance Share Awards			9.3	—
EQUITY				
Common Stock – Par Value – $6.50 Per Share:				
	2017	2016		
Shares Authorized	600,000,000	600,000,000		
Shares Issued	512,048,663	512,048,520		
(20,206,368 and 20,336,592 Shares were Held in Treasury as of September 30, 2017 and December 31, 2016, Respectively)			3,328.3	3,328.3
Paid-in Capital			6,384.2	6,332.6
Retained Earnings			8,532.0	7,892.4
Accumulated Other Comprehensive Income (Loss)			(175.4)	(156.3)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			18,069.1	17,397.0
Noncontrolling Interests			36.4	23.1
TOTAL EQUITY			18,105.5	17,420.1
TOTAL LIABILITIES, MEZZANINE EQUITY AND TOTAL EQUITY			$63,964.9	$ 63,467.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2017	2016
OPERATING ACTIVITIES		
Net Income	$1,527.1	$242.8
Loss from Discontinued Operations, Net of Tax	—	(2.5)
Income from Continuing Operations	1,527.1	245.3
Adjustments to Reconcile Income from Continuing Operations to Net Cash Flows from Continuing Operating Activities:		
Depreciation and Amortization	1,485.9	1,550.2
Deferred Income Taxes	740.9	(47.0)
Asset Impairments and Other Related Charges	10.6	2,264.9
Allowance for Equity Funds Used During Construction	(62.2)	(86.1)
Mark-to-Market of Risk Management Contracts	(56.2)	56.6
Amortization of Nuclear Fuel	104.8	109.7
Pension Contributions to Qualified Plan Trust	(93.3)	(84.8)
Property Taxes	291.4	288.3
Deferred Fuel Over/Under-Recovery, Net	81.0	(28.5)
Gain on Sale of Merchant Generation Assets	(226.4)	—
Gain on Sale of Equity Investment	(12.4)	—
Recovery of Ohio Capacity Costs	65.6	108.8
Provision for Refund – Global Settlement, Net	(93.3)	—
Change in Other Noncurrent Assets	(345.2)	(243.4)
Change in Other Noncurrent Liabilities	205.7	41.3
Changes in Certain Components of Continuing Working Capital:		
Accounts Receivable, Net	201.3	(240.8)
Fuel, Materials and Supplies	58.5	11.6
Accounts Payable	(91.0)	47.8
Accrued Taxes, Net	(310.1)	(393.0)
Other Current Assets	(98.2)	31.5
Other Current Liabilities	(260.3)	(211.4)
Net Cash Flows from Continuing Operating Activities	3,124.2	3,421.0
INVESTING ACTIVITIES		
Construction Expenditures	(3,778.2)	(3,387.0)
Change in Other Temporary Investments, Net	34.5	109.2
Purchases of Investment Securities	(1,855.8)	(2,454.5)
Sales of Investment Securities	1,808.6	2,427.0
Acquisitions of Nuclear Fuel	(73.2)	(127.6)
Proceeds from Sale of Merchant Generation Assets	2,159.6	—
Other Investing Activities	27.9	4.2
Net Cash Flows Used for Continuing Investing Activities	(1,676.6)	(3,428.7)

FINANCING ACTIVITIES		
Issuance of Common Stock	—	34.2
Issuance of Long-term Debt	2,742.7	1,559.6
Change in Short-term Debt, Net	(653.7)	678.3
Retirement of Long-term Debt	(2,427.2)	(1,307.6)
Make Whole Premium on Extinguishment of Long-term Debt	(46.1)	—
Principal Payments for Capital Lease Obligations	(50.5)	(81.9)
Dividends Paid on Common Stock	(875.0)	(829.8)
Other Financing Activities	(4.4)	(6.8)
Net Cash Flows from (Used for) Continuing Financing Activities	(1,314.2)	46.0
Net Cash Flows Used for Discontinued Operating Activities	—	(2.5)
Net Cash Flows from Discontinued Investing Activities	—	—
Net Cash Flows from Discontinued Financing Activities	—	—
Net Increase in Cash and Cash Equivalents	133.4	35.8
Cash and Cash Equivalents at Beginning of Period	210.5	176.4
Cash and Cash Equivalents at End of Period	$343.9	$212.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

Summary of Investment in Transmission Assets for AEPTCo

	As of September 30,	
	2017	2016
	(in millions)	
Plant In Service	$4,684.4	$3,260.7
CWIP	1,383.1	1,328.6
Accumulated Depreciation	151.5	86.6
Total Transmission Property, Net	$5,916.0	$4,502.7

Third Quarter of 2017 Compared to Third Quarter of 2016
Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Net Income
(in millions)

Third Quarter of 2016	$52.4
Changes in Transmission Revenues:	
Transmission Revenues	42.0
Total Change in Transmission Revenues	42.0
Changes in Expenses and Other:	
Other Operation and Maintenance	(10.4)
Depreciation and Amortization	(8.0)
Taxes Other Than Income Taxes	(4.9)
Interest Income	0.1
Allowance for Equity Funds Used During Construction	(1.6)
Interest Expense	(5.9)
Total Change in Expenses and Other	(30.7)
Income Tax Expense	(3.8)
Third Quarter of 2017	$59.9

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

- Transmission Revenues increased $42 million primarily due to a $40 million increase in formula rates driven by continued investment in transmission assets.

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

- Other Operation and Maintenance expenses increased $10 million primarily due to increased transmission investment.

- Depreciation and Amortization expenses increased $8 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $5 million primarily due to increased property taxes as a result of additional transmission investment.
- Interest Expense increased $6 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $4 million primarily due to an increase in pretax book income.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Reconciliation of Nine Months Ended September 30, 2016 to
Nine Months Ended September 30, 2017
Net Income
(in millions)

Nine Months Ended September 30, 2016	$153.0
Changes in Transmission Revenues:	
Transmission Revenues	191.4
Total Change in Transmission Revenues	191.4
Changes in Expenses and Other:	
Other Operation and Maintenance	(19.8)
Depreciation and Amortization	(23.4)
Taxes Other Than Income Taxes	(16.6)
Interest Income	0.3
Allowance for Equity Funds Used During Construction	(3.7)
Interest Expense	(16.3)
Total Change in Expenses and Other	(79.5)
Income Tax Expense	(40.6)
Nine Months Ended September 30, 2017	$224.3

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 $191 million primarily due to the current year favorable impact of the modification of the PJM OATT formula rates combined with an increase driven by continued investment in transmission assets.

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

- Other Operation and Maintenance expenses increased $20 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $23 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.
- Allowance for Equity Funds Used During Construction decreased $4 million primarily due to the FERC transmission complaint and an increase in the amount of short term debt, offset by an increase in the CWIP balance.
- Interest Expense increased $16 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $41 million primarily due to an increase in pretax book income.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
REVENUES				
Transmission Revenues	$35.9	$33.5	$99.2	$89.6
Sales to AEP Affiliates	131.4	91.8	450.2	268.4
TOTAL REVENUES	167.3	125.3	549.4	358.0
EXPENSES				
Other Operation	18.4	7.5	38.8	21.0
Maintenance	1.4	1.9	6.8	4.8
Depreciation and Amortization	24.8	16.8	70.9	47.5
Taxes Other Than Income Taxes	27.6	22.7	82.0	65.4
TOTAL EXPENSES	72.2	48.9	198.5	138.7
OPERATING INCOME	95.1	76.4	350.9	219.3
Other Income (Expense):				
Interest Income	0.2	0.1	0.5	0.2
Allowance for Equity Funds Used During Construction	11.7	13.3	36.0	39.7
Interest Expense	(16.9)	(11.0)	(48.6)	(32.3)
INCOME BEFORE INCOME TAX EXPENSE	90.1	78.8	338.8	226.9
Income Tax Expense	30.2	26.4	114.5	73.9
NET INCOME	$59.9	$52.4	$224.3	$153.0

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 118.

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AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER’S EQUITY
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Total Member’s Equity
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2015	$ 1,243.0	$ 309.9	$ 1,552.9
Capital Contributions from Member	116.0		116.0
Net Income		153.0	153.0
TOTAL MEMBER'S EQUITY – SEPTEMBER 30, 2016	$ 1,359.0	$ 462.9	$ 1,821.9
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2016	$ 1,455.0	$ 502.6	$ 1,957.6
Capital Contributions from Member	185.5		185.5
Net Income		224.3	224.3
TOTAL MEMBER'S EQUITY – SEPTEMBER 30, 2017	$ 1,640.5	$ 726.9	$ 2,367.4

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 118.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2017 and December 31, 2016
(in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT ASSETS		
Advances to Affiliates	$ 290.9	$ 67.1
Accounts Receivable:		
Customers	19.5	11.3
Affiliated Companies	102.8	66.6
Total Accounts Receivable	122.3	77.9
Materials and Supplies	16.0	5.0
Accrued Tax Benefits	12.7	26.0
Prepayments and Other Current Assets	8.1	2.8
TOTAL CURRENT ASSETS	450.0	178.8
TRANSMISSION PROPERTY		
Transmission Property	4,570.9	3,973.5
Other Property, Plant and Equipment	113.5	99.4
Construction Work in Progress	1,383.1	981.3
Total Transmission Property	6,067.5	5,054.2
Accumulated Depreciation and Amortization	151.5	99.6
TOTAL TRANSMISSION PROPERTY – NET	5,916.0	4,954.6
OTHER NONCURRENT ASSETS		
Accounts Receivable - Affiliated Companies	13.8	—
Regulatory Assets	138.0	112.3
Deferred Property Taxes	29.8	102.2
Deferred Charges and Other Noncurrent Assets	1.3	1.9
TOTAL OTHER NONCURRENT ASSETS	182.9	216.4
TOTAL ASSETS	$ 6,548.9	$ 5,349.8

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 118.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND MEMBER'S EQUITY
September 30, 2017 and December 31, 2016
(in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT LIABILITIES		
Advances from Affiliates	$ 32.8	$ 4.1
Accounts Payable:		
General	233.2	289.7
Affiliated Companies	50.0	43.1
Accrued Taxes	112.5	191.8
Accrued Interest	28.9	10.5
Other Current Liabilities	10.4	10.9
TOTAL CURRENT LIABILITIES	467.8	550.1
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,550.0	1,932.0
Deferred Income Taxes	1,073.1	862.1
Regulatory Liabilities	60.5	44.0
Deferred Credits and Other Noncurrent Liabilities	30.1	4.0
TOTAL NONCURRENT LIABILITIES	3,713.7	2,842.1
TOTAL LIABILITIES	4,181.5	3,392.2
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEMBER'S EQUITY		
Paid-in Capital	1,640.5	1,455.0
Retained Earnings	726.9	502.6
TOTAL MEMBER'S EQUITY	2,367.4	1,957.6
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 6,548.9	$ 5,349.8

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 118.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2017	2016
OPERATING ACTIVITIES		
Net Income	$224.3	$153.0
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	70.9	47.5
Deferred Income Taxes	193.0	161.2
Allowance for Equity Funds Used During Construction	(36.0)	(39.7)
Property Taxes	72.4	63.5
Long-term Accounts Receivable - Affiliated	(13.8)	—
Change in Other Noncurrent Assets	7.6	(6.4)
Change in Other Noncurrent Liabilities	25.7	0.6
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(44.4)	(43.3)
Materials and Supplies	(11.0)	(1.5)
Accounts Payable	8.6	(1.7)
Accrued Taxes, Net	(66.0)	61.2
Accrued Interest	18.4	11.3
Other Current Assets	(5.3)	(0.1)
Other Current Liabilities	0.5	0.1
Net Cash Flows from Operating Activities	444.9	405.7
INVESTING ACTIVITIES		
Construction Expenditures	(1,050.7)	(799.8)
Change in Advances to Affiliates, Net	(223.8)	83.7
Other Investing Activities	(2.9)	(4.6)
Net Cash Flows Used for Investing Activities	(1,277.4)	(720.7)
FINANCING ACTIVITIES		
Capital Contributions from Member	185.5	116.0
Issuance of Long-term Debt - Nonaffiliated	618.3	—
Change in Advances from Affiliates, Net	28.7	199.0
Net Cash Flows from Financing Activities	832.5	315.0
Net Change in Cash and Cash Equivalents	—	—
Cash and Cash Equivalents at Beginning of Period	—	—
Cash and Cash Equivalents at End of Period	$—	$—
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$28.6	$20.0
Net Cash Paid (Received) for Income Taxes	(93.4)	(209.8)
Construction Expenditures Included in Current Liabilities as of September 30,	239.0	204.8

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 118.

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,	
	2017	2016	2017	2016
	(in millions of KWhs)			
Retail:				
Residential	2,488	2,845	7,829	8,743
Commercial	1,673	1,823	4,805	5,125
Industrial	2,431	2,391	7,106	7,022
Miscellaneous	202	217	613	637
Total Retail	6,794	7,276	20,353	21,527
Wholesale	994	1,029	2,684	2,413
Total KWhs	7,788	8,305	23,037	23,940

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,	
	2017	2016	2017	2016
	(in degree days)			
Actual - Heating (a)	—	—	1,000	1,433
Normal - Heating (b)	2	2	1,420	1,437
Actual - Cooling (c)	805	1,049	1,180	1,437
Normal - Cooling (b)	812	808	1,179	1,177

(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.

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Third Quarter of 2017 Compared to Third Quarter of 2016
Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Net Income
(in millions)

Third Quarter of 2016	$104.1
Changes in Gross Margin:	
Retail Margins	(40.6)
Off-system Sales	(1.0)
Transmission Revenues	1.8
Other Revenues	0.5
Total Change in Gross Margin	(39.3)
Changes in Expenses and Other:	
Other Operation and Maintenance	12.9
Depreciation and Amortization	(4.7)
Taxes Other Than Income Taxes	(0.3)
Carrying Costs Income	0.4
Allowance for Equity Funds Used During Construction	(1.8)
Interest Expense	(0.8)
Total Change in Expenses and Other	5.7
Income Tax Expense	15.5
Third Quarter of 2017	$86.0

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 $25 million decrease in weather-related usage primarily driven by a 23% decrease in cooling degree days.
  - An $8 million decrease in weather-normalized margin occurring across all retail classes.
  - A $6 million decrease primarily due to a decrease in rates in West Virginia and Virginia. This decrease is partially offset by a corresponding decrease in Other Operation and Maintenance expenses below.

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

- Other Operation and Maintenance expenses decreased $13 million primarily due to the following:
  - A $7 million decrease in storm-related expenses.
  - A $4 million decrease in generation plant maintenance expenses.
- Depreciation and Amortization expenses increased $5 million primarily due to a higher depreciable base.
- Income Tax Expense decreased $16 million primarily due to a decrease in pretax book income and the recording of federal income tax adjustments.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Reconciliation of Nine Months Ended September 30, 2016 to
Nine Months Ended September 30, 2017
Net Income
(in millions)

Nine Months Ended September 30, 2016	$303.8
Changes in Gross Margin:	
Retail Margins	(93.7)
Off-system Sales	(0.1)
Transmission Revenues	25.9
Other Revenues	3.2
Total Change in Gross Margin	(64.7)
Changes in Expenses and Other:	
Other Operation and Maintenance	(8.3)
Depreciation and Amortization	(14.1)
Taxes Other Than Income Taxes	0.6
Interest Income	0.3
Carrying Costs Income	0.8
Allowance for Equity Funds Used During Construction	(2.9)
Interest Expense	(2.8)
Total Change in Expenses and Other	(26.4)
Income Tax Expense	36.0
Nine Months Ended September 30, 2017	$248.7

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 $94 million primarily due to the following:
  - A $72 million decrease in weather-related usage primarily driven by a 30% decrease in heating degree days and an 18% decrease in cooling degree days.
  - A $14 million decrease primarily due to prior year recognition of deferred billing in West Virginia as approved by the WVPSC.
  - A $3 million decrease in weather-normalized margin primarily driven by the commercial class.
- Transmission Revenues increased $26 million primarily due to increase in formula rates driven by continued investment in transmission assets. This increase is partially offset 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 $8 million primarily due to the following:
  - A $13 million increase in recoverable PJM transmission expenses. This increase in expense is offset within Gross Margin above.
  - A $6 million gain on the sale of property in 2016.

These increases were partially offset by:

- An $8 million decrease in storm-related expenses.
- A $5 million decrease in employee-related expenses.
- Depreciation and Amortization expenses increased $14 million primarily due to a higher depreciable base.
- Income Tax Expense decreased $36 million primarily due to a decrease in pretax book income and the recording of federal income tax adjustments.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2017	2016	2017	2016
REVENUES				
Electric Generation, Transmission and Distribution	$674.4	$739.0	$2,045.0	$2,153.3
Sales to AEP Affiliates	41.9	36.4	130.6	109.0
Other Revenues	3.0	2.8	11.8	9.4
TOTAL REVENUES	719.3	778.2	2,187.4	2,271.7
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	178.6	190.1	498.3	494.1
Purchased Electricity for Resale	61.1	69.2	217.1	240.9
Other Operation	115.7	117.6	366.2	349.4
Maintenance	55.8	66.8	187.8	196.3
Depreciation and Amortization	102.8	98.1	304.1	290.0
Taxes Other Than Income Taxes	32.3	32.0	93.3	93.9
TOTAL EXPENSES	546.3	573.8	1,666.8	1,664.6
OPERATING INCOME	173.0	204.4	520.6	607.1
Other Income (Expense):				
Interest Income	0.3	0.3	1.1	0.8
Carrying Costs Income	0.4	—	1.0	0.2
Allowance for Equity Funds Used During Construction	2.7	4.5	6.2	9.1
Interest Expense	(47.2)	(46.4)	(143.5)	(140.7)
INCOME BEFORE INCOME TAX EXPENSE	129.2	162.8	385.4	476.5
Income Tax Expense	43.2	58.7	136.7	172.7
NET INCOME	$86.0	$104.1	$248.7	$303.8

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

See Condensed Notes to Condensed

Financial Statements of Registrants beginning on page 118.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net Income	$86.0	$104.1	$248.7	$303.8
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, 2017 and 2016, Respectively, and $(0.3) and $(0.3) for the Nine Months Ended September 30, 2017 and 2016, Respectively	(0.1)	(0.2)	(0.5)	(0.6)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended September 30, 2017 and 2016, Respectively, and $(0.4) and $(0.5) for the Nine Months Ended September 30, 2017 and 2016, Respectively	(0.3)	(0.3)	(0.9)	(1.0)
TOTAL OTHER COMPREHENSIVE LOSS	(0.4)	(0.5)	(1.4)	(1.6)
TOTAL COMPREHENSIVE INCOME	$85.6	$103.6	$247.3	$302.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2016	$ 260.4	$ 1,828.7	$ 1,502.8	$ (8.4)	$ 3,583.5
Common Stock Dividends			(90.0)		(90.0)
Net Income			248.7		248.7
Other Comprehensive Loss				(1.4)	(1.4)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2017	$ 260.4	$ 1,828.7	$ 1,661.5	$ (9.8)	$ 3,740.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2017 and December 31, 2016
(in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents	$2.9	$ 2.7
Restricted Cash for Securitized Funding	8.3	15.8
Advances to Affiliates	23.6	24.1
Accounts Receivable:		
Customers	96.8	131.4
Affiliated Companies	59.5	54.4
Accrued Unbilled Revenues	41.1	52.7
Miscellaneous	1.3	0.9
Allowance for Uncollectible Accounts	(2.7)	(3.5)
Total Accounts Receivable	196.0	235.9
Fuel	96.3	112.0
Materials and Supplies	100.8	98.8
Risk Management Assets	30.3	2.6
Accrued Tax Benefits	0.4	4.2
Regulatory Asset for Under-Recovered Fuel Costs	63.5	68.4
Margin Deposits	11.8	17.5
Prepayments and Other Current Assets	18.2	9.7
TOTAL CURRENT ASSETS	552.1	591.7
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,393.7	6,332.8
Transmission	2,904.4	2,796.9
Distribution	3,703.5	3,569.1
Other Property, Plant and Equipment	409.8	373.5
Construction Work in Progress	493.5	390.3
Total Property, Plant and Equipment	13,904.9	13,462.6
Accumulated Depreciation and Amortization	3,836.7	3,636.8
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	10,068.2	9,825.8
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,100.1	1,121.1
Securitized Assets	288.0	305.3
Long-term Risk Management Assets	0.6	—
Deferred Charges and Other Noncurrent Assets	113.6	133.3
TOTAL OTHER NONCURRENT ASSETS	1,502.3	1,559.7
TOTAL ASSETS	$12,122.6	$ 11,977.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2017 and December 31, 2016
(Unaudited)

	September 30, 2017	December 31, 2016
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$69.5	$ 79.6
Accounts Payable:		
General	235.4	253.7
Affiliated Companies	75.5	82.6
Long-term Debt Due Within One Year - Nonaffiliated	149.2	503.1
Risk Management Liabilities	0.9	0.3
Customer Deposits	84.0	83.1
Accrued Taxes	64.0	107.6
Accrued Interest	71.4	40.6
Other Current Liabilities	99.2	129.5
TOTAL CURRENT LIABILITIES	849.1	1,280.1
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	3,830.1	3,530.8
Long-term Risk Management Liabilities	0.3	0.9
Deferred Income Taxes	2,796.7	2,672.3
Regulatory Liabilities and Deferred Investment Tax Credits	634.4	627.8
Asset Retirement Obligations	101.2	108.8
Employee Benefits and Pension Obligations	92.2	108.5
Deferred Credits and Other Noncurrent Liabilities	77.8	64.5
TOTAL NONCURRENT LIABILITIES	7,532.7	7,113.6
TOTAL LIABILITIES	8,381.8	8,393.7
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	1,661.5	1,502.8
Accumulated Other Comprehensive Income (Loss)	(9.8)	(8.4)
TOTAL COMMON SHAREHOLDER'S EQUITY	3,740.8	3,583.5
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$12,122.6	$ 11,977.2

See
Condensed

Notes to Condensed Financial Statements of Registrants beginning on page 118.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2017		2016	
OPERATING ACTIVITIES				
Net Income	$ 248.7		$ 303.8	
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:				
Depreciation and Amortization	304.1		290.0	
Deferred Income Taxes	121.7		100.9	
Carrying Costs Income	(1.0	)	(0.2	)
Allowance for Equity Funds Used During Construction	(6.2	)	(9.1	)
Mark-to-Market of Risk Management Contracts	(28.3	)	18.4	
Pension Contributions to Qualified Plan Trust	(10.2	)	(8.8	)
Property Taxes	29.8		29.2	
Deferred Fuel Over/Under-Recovery, Net	4.9		19.0	
Change in Other Noncurrent Assets	8.3		(5.1	)
Change in Other Noncurrent Liabilities	7.9		(23.0	)
Changes in Certain Components of Working Capital:				
Accounts Receivable, Net	39.9		(20.5	)
Fuel, Materials and Supplies	14.0		(1.2	)
Accounts Payable	6.2		4.9	
Accrued Taxes, Net	(44.2	)	(13.9	)
Other Current Assets	(2.5	)	(0.2	)
Other Current Liabilities	9.1		(4.1	)
Net Cash Flows from Operating Activities	702.2		680.1	
INVESTING ACTIVITIES				
Construction Expenditures	(560.0	)	(472.7	)
Change in Restricted Cash for Securitized Funding	7.5		7.0	
Change in Advances to Affiliates, Net	0.5		1.2	
Other Investing Activities	11.8		10.6	
	(540.2	)	(453.9	)

Net Cash Flows Used for Investing Activities		
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Nonaffiliated	320.9	314.1
Change in Advances from Affiliates, Net	(10.1)	(96.9)
Retirement of Long-term Debt - Nonaffiliated	(377.9)	(213.6)
Principal Payments for Capital Lease Obligations	(5.2)	(4.7)
Dividends Paid on Common Stock	(90.0)	(225.0)
Other Financing Activities	0.5	0.4
Net Cash Flows Used for Financing Activities	(161.8)	(225.7)
Net Increase in Cash and Cash Equivalents	0.2	0.5
Cash and Cash Equivalents at Beginning of Period	2.7	2.8
Cash and Cash Equivalents at End of Period	$ 2.9	$ 3.3
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 107.1	$ 113.2
Net Cash Paid for Income Taxes	24.4	55.8
Noncash Acquisitions Under Capital Leases	2.9	2.1
Construction Expenditures Included in Current Liabilities as of September 30,	107.2	66.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

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,	
	2017	2016	2017	2016
	(in millions of KWhs)			
Retail:				
Residential	1,404	1,619	4,015	4,344
Commercial	1,313	1,405	3,640	3,780
Industrial	1,978	1,996	5,793	5,876
Miscellaneous	16	15	50	50
Total Retail	4,711	5,035	13,498	14,050
Wholesale	2,807	2,613	8,567	7,038
Total KWhs	7,518	7,648	22,065	21,088

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,	
	2017	2016	2017	2016
	(in degree days)			
Actual - Heating (a)	—	—	1,816	2,196
Normal - Heating (b)	11	10	2,430	2,449
Actual - Cooling (c)	504	741	764	1,011
Normal - Cooling (b)	574	571	835	835

(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 2017 Compared to Third Quarter of 2016

Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Net Income
(in millions)

Third Quarter of 2016	$75.4
Changes in Gross Margin:	
Retail Margins (a)	(4.4)
Transmission Revenues	(6.2)
Other Revenues	(1.5)
Total Change in Gross Margin	(12.1)
Changes in Expenses and Other:	
Other Operation and Maintenance	(7.4)
Asset Impairments and Other Related Charges	10.5
Depreciation and Amortization	(5.9)
Taxes Other Than Income Taxes	(1.4)
Other Income	0.1
Interest Expense	(0.8)
Total Change in Expenses and Other	(4.9)
Income Tax Expense	6.5
Third Quarter of 2017	$64.9

(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 $4 million primarily due to the following:
- An $18 million decrease in weather-related usage primarily due to a 32% decrease in cooling degree days.
- A $6 million decrease in weather-normalized margins.
- A $5 million decrease in FERC generation wholesale municipal and cooperative revenues primarily due to formula rate adjustments.
- A $2 million decrease due to increased costs for power acquired under the Unit Power Agreement between AEGCo and I&M.

These decreases were partially offset by:
- A $13 million increase from rate proceedings in the I&M service territory. The increase in retail margins relating to riders has corresponding increases in other items below.
- A $9 million increase related to over/under recovery of riders.
- A $2 million decrease in PJM related expenses primarily due to reduced FTRs.
- Transmission Revenues decreased $6 million primarily due to an annual formula rate true-up and reduced net PJM Network Integration Transmission Service revenues resulting from increased affiliated transmission-related charges.

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 $9 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses. This increase in expense is offset within Retail Margins above.
  - A $3 million increase in nuclear expenses primarily due to an increase in refueling outage amortization and refueling outage expenses not deferred, partially offset by a decrease in employee-related expenses.

  These increases were partially offset by:
  - A $3 million decrease in distribution expenses primarily due to decreased vegetation management.
- Asset Impairments and Other Related Charges decreased $11 million due to the impairment of I&M's Price River coal reserves in 2016.
- Depreciation and Amortization expenses increased $6 million primarily due to higher depreciable base.
- Income Tax Expense decreased $7 million primarily due to a decrease in pretax book income and the regulatory accounting treatment of state income taxes.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Reconciliation of Nine Months Ended September 30,
2016 to Nine Months Ended September 30, 2017
Net Income
(in millions)

Nine Months Ended September 30, 2016	$ 201.4
Changes in Gross Margin:	
Retail Margins (a)	(11.2)
Off-system Sales	0.5
Transmission Revenues	(23.0)
Other Revenues	(2.1)
Total Change in Gross Margin	(35.8)
Changes in Expenses and Other:	
Other Operation and Maintenance	(39.3)
Asset Impairments and Other Related Charges	10.5
Depreciation and Amortization	(11.6)
Taxes Other Than Income Taxes	3.2
Other Income	(0.4)
Interest Expense	(6.7)
Total Change in Expenses and Other	(44.3)
Income Tax Expense	22.5
Nine Months Ended September 30, 2017	$ 143.8

(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 $11 million primarily due to the following:
  - A $33 million decrease in FERC generation wholesale municipal and cooperative revenues primarily due to an annual formula rate true-up and other rate adjustments.
  - A $29 million decrease in weather-related usage primarily due to a 24% decrease in cooling degree days and a 17% decrease in heating degree days.
  - An $11 million decrease in weather-normalized margins.
  - A $5 million decrease due to increased costs for power acquired under the Unit Power Agreement between AEGCo and I&M.

  These decreases were partially offset by:
  - A $47 million increase from rate proceedings in the I&M service territory. The increase in retail margins relating to riders has corresponding increases in other items below.
  - A $19 million increase related to over/under recovery of riders.
  - A $2 million decrease in PJM related expenses primarily due to reduced FTRs.
- Transmission Revenues decreased $23 million primarily due to an annual formula rate true-up and reduced net PJM Network Integration Transmission Service revenues resulting from increased affiliated transmission-related charges.

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

- Other Operation and Maintenance expenses increased $39 million primarily due to the following:
- A $38 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses. This increase in expense was offset within Retail Margins above.
- A $7 million increase in nuclear expenses primarily due to an increase in refueling outage amortization, partially offset by refueling outage expenses not deferred, a decrease in employee-related expenses and material write-off.
- A $3 million increase in distribution expenses primarily due to increased vegetation management.

These increases were partially offset by:

- An $8 million decrease primarily due to employee-related expenses.
- Asset Impairments and Other Related Charges decreased $11 million due to the impairment of I&M’s Price River coal reserves in 2016.
- Depreciation and Amortization expenses increased $12 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes decreased $3 million primarily due to property taxes.
- Interest Expense increased $7 million primarily due to higher long-term debt balances.
- Income Tax Expense decreased $23 million primarily due to a decrease in pretax book income, partially offset by the recording of favorable federal income tax adjustments in 2016.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2017	2016	2017	2016
REVENUES				
Electric Generation, Transmission and Distribution	$537.0	$574.7	$1,527.4	$1,570.8
Other Revenues – Affiliated	17.1	19.5	48.2	68.7
Other Revenues – Nonaffiliated	3.6	3.4	9.9	13.2
TOTAL REVENUES	557.7	597.6	1,585.5	1,652.7
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	76.4	91.3	238.2	236.8
Purchased Electricity for Resale	32.9	43.7	101.2	134.3
Purchased Electricity from AEP Affiliates	62.4	64.5	166.2	165.9
Other Operation	140.5	138.9	434.2	413.9
Maintenance	51.5	45.7	153.6	134.6
Asset Impairments and Other Related Charges	—	10.5	—	10.5
Depreciation and Amortization	55.0	49.1	154.8	143.2
Taxes Other Than Income Taxes	23.9	22.5	68.3	71.5
TOTAL EXPENSES	442.6	466.2	1,316.5	1,310.7
OPERATING INCOME	115.1	131.4	269.0	342.0
Other Income (Expense):				
Interest Income	2.4	1.7	11.5	9.1
Allowance for Equity Funds Used During Construction	3.5	4.1	8.1	10.9
Interest Expense	(27.5)	(26.7)	(83.0)	(76.3)
INCOME BEFORE INCOME TAX EXPENSE	93.5	110.5	205.6	285.7
Income Tax Expense	28.6	35.1	61.8	84.3
NET INCOME	$64.9	$75.4	$143.8	$201.4

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net Income	$64.9	$75.4	$143.8	$201.4
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, 2017 and 2016, Respectively, and $0.5 and $0.5 for the Nine Months Ended September 30, 2017 and 2016, Respectively	0.3	0.3	1.0	1.0
TOTAL COMPREHENSIVE INCOME	$65.2	$75.7	$144.8	$202.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2016	$ 56.6	$ 980.9	$ 1,130.5	$ (16.2)	$ 2,151.8
Common Stock Dividends			(93.7)		(93.7)
Net Income			143.8		143.8
Other Comprehensive Income				1.0	1.0
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2017	$ 56.6	$ 980.9	$ 1,180.6	$ (15.2)	$ 2,202.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2017 and December 31, 2016
(in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents	$1.3	$ 1.2
Advances to Affiliates	12.6	12.5
Accounts Receivable:		
Customers	42.1	60.2
Affiliated Companies	42.8	51.0
Accrued Unbilled Revenues	8.4	1.5
Miscellaneous	1.1	0.7
Allowance for Uncollectible Accounts	(0.3)	—
Total Accounts Receivable	94.1	113.4
Fuel	32.3	32.3
Materials and Supplies	156.5	150.8
Risk Management Assets	11.6	3.5
Accrued Tax Benefits	34.5	37.7
Regulatory Asset for Under-Recovered Fuel Costs	12.3	26.1
Accrued Reimbursement of Spent Nuclear Fuel Costs	11.0	22.1
Prepayments and Other Current Assets	26.9	19.9
TOTAL CURRENT ASSETS	393.1	419.5
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,399.9	4,056.1
Transmission	1,491.4	1,472.8
Distribution	2,000.1	1,899.3
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	555.9	550.2
Construction Work in Progress	478.9	654.2
Total Property, Plant and Equipment	8,926.2	8,632.6
Accumulated Depreciation, Depletion and Amortization	3,022.5	3,005.1
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,903.7	5,627.5
OTHER NONCURRENT ASSETS		
Regulatory Assets	941.0	916.6
Spent Nuclear Fuel and Decommissioning Trusts	2,433.0	2,256.2
Long-term Risk Management Assets	0.5	—
Deferred Charges and Other Noncurrent Assets	95.9	121.5
TOTAL OTHER NONCURRENT ASSETS	3,470.4	3,294.3
TOTAL ASSETS	$9,767.2	$ 9,341.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2017 and December 31, 2016
(dollars in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT LIABILITIES		
Advances from Affiliates	$177.5	$ 215.2
Accounts Payable:		
General	168.6	179.0
Affiliated Companies	72.2	75.6
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2017 and December 31, 2016 Amounts Include $83.7 and $130.9, Respectively, Related to DCC Fuel)	462.1	209.3
Risk Management Liabilities	2.0	0.3
Customer Deposits	37.3	34.3
Accrued Taxes	43.8	77.2
Accrued Interest	14.3	31.7
Obligations Under Capital Leases	7.3	9.4
Other Current Liabilities	114.3	123.4
TOTAL CURRENT LIABILITIES	1,099.4	955.4
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,196.4	2,262.1
Long-term Risk Management Liabilities	0.2	0.8
Deferred Income Taxes	1,681.8	1,527.4
Regulatory Liabilities and Deferred Investment Tax Credits	1,169.6	1,065.5
Asset Retirement Obligations	1,307.4	1,257.9
Deferred Credits and Other Noncurrent Liabilities	109.5	120.4
TOTAL NONCURRENT LIABILITIES	6,464.9	6,234.1
TOTAL LIABILITIES	7,564.3	7,189.5
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	1,180.6	1,130.5
Accumulated Other Comprehensive Income (Loss)	(15.2)	(16.2)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,202.9	2,151.8
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$9,767.2	$ 9,341.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2017		2016	
OPERATING ACTIVITIES				
Net Income	$ 143.8		$ 201.4	
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:				
Depreciation and Amortization	154.8		143.2	
Deferred Income Taxes	132.2		116.2	
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	15.5		(17.4	)
Asset Impairments and Other Related Charges	—		10.5	
Allowance for Equity Funds Used During Construction	(8.1	)	(10.9	)
Mark-to-Market of Risk Management Contracts	(7.5	)	0.5	
Amortization of Nuclear Fuel	104.8		109.7	
Pension Contribution to Qualified Plan Trust	(13.0	)	(12.7	)
Deferred Fuel Over/Under-Recovery, Net	22.0		6.1	
Change in Other Noncurrent Assets	(42.1	)	—	
Change in Other Noncurrent Liabilities	40.9		30.0	
Changes in Certain Components of Working Capital:				
Accounts Receivable, Net	19.3		17.0	
Fuel, Materials and Supplies	(4.1	)	(1.1	)
Accounts Payable	16.6		(17.9	)
Accrued Taxes, Net	(30.2	)	(16.5	)
Other Current Assets	8.0		6.7	
Other Current Liabilities	(28.6	)	(27.8	)
Net Cash Flows from Operating Activities	524.3		537.0	
INVESTING ACTIVITIES				
Construction Expenditures	(469.2	)	(405.1	)
	(0.1	)	(0.7	)

Change in Advances to Affiliates, Net		
Purchases of Investment Securities	(1,842.2)	(2,452.9)
Sales of Investment Securities	1,808.6	2,427.0
Acquisitions of Nuclear Fuel	(73.2)	(127.6)
Other Investing Activities	7.3	7.8
Net Cash Flows Used for Investing Activities	(568.8)	(551.5)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	411.1	482.7
Change in Advances from Affiliates, Net	(37.7)	(268.0)
Retirement of Long-term Debt – Nonaffiliated	(227.1)	(76.8)
Principal Payments for Capital Lease Obligations	(8.7)	(29.8)
Dividends Paid on Common Stock	(93.7)	(93.8)
Other Financing Activities	0.7	0.7
Net Cash Flows from Financing Activities	44.6	15.0
Net Increase in Cash and Cash Equivalents	0.1	0.5
Cash and Cash Equivalents at Beginning of Period	1.2	1.1
Cash and Cash Equivalents at End of Period	$ 1.3	$ 1.6
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 92.0	$ 85.6
Net Cash Paid (Received) for Income Taxes	(69.6)	(36.0)
Noncash Acquisitions Under Capital Leases	5.9	16.8
Construction Expenditures Included in Current Liabilities as of September 30,	74.5	83.4
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	0.6	0.3
Expected Reimbursement for Capital Cost of Spent Nuclear Fuel Dry Cask Storage	2.8	0.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

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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,	
	2017	2016	2017	2016
	(in millions of KWhs)			
Retail:				
Residential	3,644	4,380	10,198	11,209
Commercial	3,806	4,114	10,789	11,158
Industrial	3,708	3,610	10,967	10,671
Miscellaneous	28	27	87	89
Total Retail (a)	11,186	12,131	32,041	33,127
Wholesale (b)	585	654	1,749	1,389
Total KWhs	11,771	12,785	33,790	34,516

(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,	
	2017	2016	2017	2016
	(in degree days)			
Actual - Heating (a)	—	—	1,500	1,929
Normal - Heating (b)	6	7	2,091	2,110
Actual - Cooling (c)	642	900	957	1,209
Normal - Cooling (b)	670	664	960	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.

Third Quarter of 2017 Compared to Third Quarter of 2016
Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Net Income
(in millions)

Third Quarter of 2016	$99.9
Changes in Gross Margin:	
Retail Margins	(74.1)
Off-system Sales	(12.0)
Transmission Revenues	(1.8)
Other Revenues	(2.1)
Total Change in Gross Margin	(90.0)
Changes in Expenses and Other:	
Other Operation and Maintenance	59.3
Depreciation and Amortization	12.1
Taxes Other Than Income Taxes	1.5
Carrying Costs Income	(0.4)
Allowance for Equity Funds Used During Construction	0.6
Interest Expense	1.5
Total Change in Expenses and Other	74.6
Income Tax Expense	(1.9)
Third Quarter of 2017	$82.6

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

- Retail Margins decreased $74 million primarily due to the following:
  - A $52 million decrease in revenues associated with the Universal Service Fund (USF) surcharge rate decrease. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
  - An $18 million net decrease in recovery of equity carrying charges related to the Phase-In Recovery Rider (PIRR), net of associated amortizations.
  - An $8 million decrease in revenues associated with smart grid riders. This decrease was offset in various expenses below.
  - A $5 million decrease in state excise taxes due to a decrease in metered KWh. This decrease was offset by a corresponding decrease in Taxes Other Than Income Taxes below.

  These decreases were partially offset by:
  - A $12 million favorable impact due to the recovery of losses from a power contract with OVEC. The PUCO approved a PPA rider beginning in January 2017 to recover any net expense related to the deferral of OVEC losses starting in June 2016. This increase was offset by a corresponding decrease in Margins from Off-System Sales below.
- Margins from Off-system Sales decreased $12 million due to current year losses from a power contract with OVEC which was offset in Retail Margins above as a result of the OVEC PPA rider beginning in January 2017.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $59 million primarily due to the following:
  - A $52 million decrease in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This decrease was offset by a corresponding decrease in Retail Margins above.
  - A $3 million decrease in recoverable smart grid expenses. This decrease was offset in Retail Margins above.
- Depreciation and Amortization expenses decreased $12 million primarily due to the following:
  - A $5 million decrease in recoverable DIR depreciation expense in Ohio.
  - A $4 million decrease in amortization expenses for the collection of carrying costs on deferred capacity charges beginning June 2015.
  - A $4 million decrease in recoverable smart grid depreciation expenses. This decrease was offset in Retail Margins above.
- Taxes Other Than Income Taxes decreased $2 million primarily due to the following:
  - A $5 million decrease in state excise taxes due to a decrease in metered KWh. This decrease was offset by a corresponding decrease in Retail Margins above.

  This decrease was partially offset by:
  - A $3 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016
Reconciliation of Nine Months Ended September 30, 2016 to
Nine Months Ended September 30, 2017
Net Income
(in millions)

Nine Months Ended September 30, 2016	$244.7
Changes in Gross Margin:	
Retail Margins	(153.8)
Off-system Sales	(27.9)
Transmission Revenues	(2.9)
Other Revenues	(0.3)
Total Change in Gross Margin	(184.9)
Changes in Expenses and Other:	
Other Operation and Maintenance	144.3
Depreciation and Amortization	23.3
Taxes Other Than Income Taxes	(2.1)
Interest Income	1.0
Carrying Costs Income	(1.0)
Allowance for Equity Funds Used During Construction	0.4
Interest Expense	10.9
Total Change in Expenses and Other	176.8
Income Tax Expense	(5.5)
Nine Months Ended September 30, 2017	$231.1

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

- Retail Margins decreased $154 million primarily due to the following:
- A $140 million decrease in revenues associated with the USF surcharge rate decrease. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
- A $21 million decrease due to a prior year reversal of a regulatory provision resulting from a favorable court decision.
- A $13 million decrease in revenues associated with smart grid riders. This decrease was offset in various expenses below.
- A $9 million net decrease in recovery of equity carrying charges related to the PIRR, net of associated amortizations.
- A $7 million decrease in state excise taxes due to a decrease in metered KWh. This decrease was offset by a corresponding decrease in Taxes Other Than Income Taxes below.
- A $3 million decrease in transmission cost recovery rider revenues. This decrease was offset in Depreciation and Amortization below.

These decreases were partially offset by:

- A $46 million favorable impact due to the recovery of losses from a power contract with OVEC. The PUCO approved a PPA rider beginning in January 2017 to recover any net expense related to the deferral of OVEC losses starting in June 2016. This increase was offset by a corresponding decrease in Margins from Off-System Sales below.
- A $6 million increase in rider revenues associated with the DIR. This increase was partially offset in various expenses below.

- Margins from Off-system Sales decreased $28 million primarily due to the following:
  - A $46 million decrease due to current year losses from a power contract with OVEC which was offset in Retail Margins above as a result of the OVEC PPA rider beginning in January 2017.

This decrease was partially offset by:

- An $18 million increase primarily due to the impact of prior year losses from a power contract with OVEC which was not included in the OVEC PPA rider.

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

- Other Operation and Maintenance expenses decreased $144 million primarily due to the following:
  - A $140 million decrease in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This decrease was offset by a corresponding decrease in Retail Margins above.
  - An $8 million decrease in recoverable smart grid expenses. This decrease was offset in Retail Margins above.
  - A $7 million decrease in securitized customer accounts receivable expenses.
  - A $3 million decrease in employee-related expenses.

  These decreases were partially offset by:
  - A $12 million increase in PJM expenses related to the annual formula rate true-up that will be recovered in future periods.
- Depreciation and Amortization expenses decreased $23 million primarily due to the following:
  - An $11 million decrease in amortization expenses for the collection of carrying costs on deferred capacity charges beginning June 2015.
  - An $8 million decrease in recoveries of transmission cost rider carrying costs. This decrease was partially offset in Retail Margins above.
  - A $7 million decrease in recoverable DIR depreciation expense in Ohio.
  - A $5 million decrease in recoverable smart grid depreciation expenses. This decrease was offset in Retail Margins above.

  These decreases were partially offset by:
  - A $5 million increase in depreciation expense due to an increase in depreciable base of transmission and distribution assets.
  - A $3 million increase due to amortization of capitalized software costs.
- Taxes Other Than Income Taxes increased $2 million primarily due to the following:
  - A $9 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.

  This increase was partially offset by:
  - A $7 million decrease in state excise taxes due to a decrease in metered KWh. This decrease was offset by a corresponding decrease in Retail Margins above.
- Interest Expense decreased $11 million primarily due to the maturity of a senior unsecured note in June 2016.
- Income Tax Expense increased $6 million primarily due to other book/tax differences which are accounted for on a flow-through basis and the recording of federal income tax adjustments, partially offset by a decrease in pretax book income.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
REVENUES				
Electricity, Transmission and Distribution	$736.0	$864.4	$2,127.8	$2,349.2
Sales to AEP Affiliates	4.6	5.5	19.4	11.7
Other Revenues	1.4	1.4	4.8	4.8
TOTAL REVENUES	742.0	871.3	2,152.0	2,365.7
EXPENSES				
Purchased Electricity for Resale	180.7	203.4	525.4	516.1
Purchased Electricity from AEP Affiliates	26.7	35.9	83.4	121.4
Amortization of Generation Deferrals	58.7	66.1	172.9	173.0
Other Operation	125.8	184.2	377.6	525.9
Maintenance	37.9	38.8	108.4	104.4
Depreciation and Amortization	57.3	69.4	165.7	189.0
Taxes Other Than Income Taxes	100.4	101.9	293.8	291.7
TOTAL EXPENSES	587.5	699.7	1,727.2	1,921.5
OPERATING INCOME	154.5	171.6	424.8	444.2
Other Income (Expense):				
Interest Income	0.7	0.7	4.0	3.0
Carrying Costs Income	0.5	0.9	3.0	4.0
Allowance for Equity Funds Used During Construction	0.9	0.3	4.1	3.7
Interest Expense	(25.7)	(27.2)	(76.8)	(87.7)
INCOME BEFORE INCOME TAX EXPENSE	130.9	146.3	359.1	367.2
Income Tax Expense	48.3	46.4	128.0	122.5
NET INCOME	$82.6	$99.9	$231.1	$244.7

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

See Condensed Notes to Condensed

Financial Statements of Registrants beginning on page 118.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net Income	$82.6	$99.9	$231.1	$244.7
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, 2017 and 2016, Respectively, and $(0.4) and $(0.5) for the Nine Months Ended September 30, 2017 and 2016, Respectively	(0.3)	(0.2)	(0.8)	(1.0)
TOTAL COMPREHENSIVE INCOME	$82.3	$99.7	$230.3	$243.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

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OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2016	$ 321.2	$ 838.8	$ 954.5	$ 3.0	$ 2,117.5
Common Stock Dividends			(130.0)		(130.0)
Net Income			231.1		231.1
Other Comprehensive Loss				(0.8)	(0.8)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2017	$ 321.2	$ 838.8	$ 1,055.6	$ 2.2	$ 2,217.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2017 and December 31, 2016
(in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents	$3.1	$ 3.1
Restricted Cash for Securitized Funding	15.6	27.2
Advances to Affiliates	—	24.2
Accounts Receivable:		
Customers	27.1	51.1
Affiliated Companies	72.0	66.3
Accrued Unbilled Revenues	24.2	21.0
Miscellaneous	1.1	0.9
Allowance for Uncollectible Accounts	(0.4)	(0.4)
Total Accounts Receivable	124.0	138.9
Materials and Supplies	42.8	45.9
Emission Allowances	23.6	20.4
Risk Management Assets	0.2	0.2
Accrued Tax Benefits	15.4	0.1
Prepayments and Other Current Assets	28.1	10.9
TOTAL CURRENT ASSETS	252.8	270.9
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	2,349.5	2,319.2
Distribution	4,575.0	4,457.2
Other Property, Plant and Equipment	487.9	443.7
Construction Work in Progress	350.7	221.5
Total Property, Plant and Equipment	7,763.1	7,441.6
Accumulated Depreciation and Amortization	2,182.8	2,116.0
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,580.3	5,325.6
OTHER NONCURRENT ASSETS		
Notes Receivable – Affiliated	32.3	32.3
Regulatory Assets	1,014.7	1,107.5
Securitized Assets	43.7	62.1
Deferred Charges and Other Noncurrent Assets	131.2	295.5
TOTAL OTHER NONCURRENT ASSETS	1,221.9	1,497.4
TOTAL ASSETS	$7,055.0	$ 7,093.9

See
Condensed
Notes to
Condensed

Financial Statements of Registrants beginning on page 118.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2017 and December 31, 2016
(dollars in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT LIABILITIES		
Advances from Affiliates	$ 167.6	$ —
Accounts Payable:		
General	157.8	175.4
Affiliated Companies	95.3	95.6
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2017 and December 31, 2016 Amounts Include $47 and $46.3, Respectively, Related to Ohio Phase-in-Recovery Funding)	397.0	46.4
Risk Management Liabilities	7.6	5.9
Customer Deposits	62.9	71.0
Accrued Taxes	251.3	520.3
Accrued Interest	38.3	31.2
Other Current Liabilities	166.3	236.0
TOTAL CURRENT LIABILITIES	1,344.1	1,181.8
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (September 30, 2017 and December 31, 2016 Amounts Include $47.5 and $93.9, Respectively, Related to Ohio Phase-in-Recovery Funding)	1,321.9	1,717.5
Long-term Risk Management Liabilities	130.9	113.1
Deferred Income Taxes	1,460.7	1,346.1
Regulatory Liabilities and Deferred Investment Tax Credits	519.3	506.2
Employee Benefits and Pension Obligations	19.3	27.8
Deferred Credits and Other Noncurrent Liabilities	41.0	83.9
TOTAL NONCURRENT LIABILITIES	3,493.1	3,794.6
TOTAL LIABILITIES	4,837.2	4,976.4
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	1,055.6	954.5
Accumulated Other Comprehensive Income (Loss)	2.2	3.0
TOTAL COMMON SHAREHOLDER'S EQUITY	2,217.8	2,117.5

TOTAL LIABILITIES AND COMMON SHAREHOLDER’S EQUITY	$ 7,055.0	$ 7,093.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2017	2016
OPERATING ACTIVITIES		
Net Income	$231.1	$244.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	165.7	189.0
Amortization of Generation Deferrals	172.9	173.0
Deferred Income Taxes	117.5	28.6
Carrying Costs Income	(3.0)	(4.0)
Allowance for Equity Funds Used During Construction	(4.1)	(3.7)
Mark-to-Market of Risk Management Contracts	19.5	124.7
Pension Contributions to Qualified Plan Trust	(8.2)	(7.1)
Property Taxes	175.9	169.1
Provision for Refund – Global Settlement, Net	(93.3)	—
Change in Other Noncurrent Assets	(126.7)	(124.9)
Change in Other Noncurrent Liabilities	43.4	17.2
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	14.9	8.8
Materials and Supplies	(7.1)	0.5
Accounts Payable	(31.2)	2.0
Accrued Taxes, Net	(284.3)	(291.1)
Other Current Assets	(17.3)	(5.7)
Other Current Liabilities	(34.8)	(46.8)
Net Cash Flows from Operating Activities	330.9	474.3
INVESTING ACTIVITIES		
Construction Expenditures	(362.5)	(276.4)
Change in Restricted Cash for Securitized Funding	11.6	11.6
Change in Advances to Affiliates, Net	24.2	330.9
Other Investing Activities	6.9	9.0
Net Cash Flows from (Used for) Investing Activities	(319.8)	75.1
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	167.6	—
Retirement of Long-term Debt – Nonaffiliated	(46.4)	(395.9)
Principal Payments for Capital Lease Obligations	(3.1)	(3.1)
Dividends Paid on Common Stock	(130.0)	(150.0)
Other Financing Activities	0.8	0.5
Net Cash Flows Used for Financing Activities	(11.1)	(548.5)
Net Increase in Cash and Cash Equivalents	—	0.9
Cash and Cash Equivalents at Beginning of Period	3.1	3.1

Cash and Cash Equivalents at End of Period	$3.1	$4.0
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$68.1	$78.2
Net Cash Paid for Income Taxes	69.6	178.0
Noncash Acquisitions Under Capital Leases	3.6	2.4
Construction Expenditures Included in Current Liabilities as of September 30,	56.8	30.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

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,	
	2017	2016	2017	2016
	(in millions of KWhs)			
Retail:				
Residential	1,992	2,184	4,662	4,925
Commercial	1,488	1,529	3,926	4,001
Industrial	1,472	1,494	4,249	4,162
Miscellaneous	353	369	942	955
Total Retail	5,305	5,576	13,779	14,043
Wholesale	82	113	309	226
Total KWhs	5,387	5,689	14,088	14,269

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,	
	2017	2016	2017	2016
	(in degree days)			
Actual - Heating (a)	—	—	682	782
Normal - Heating (b)	1	1	1,104	1,105
Actual - Cooling (c)	1,313	1,535	2,001	2,247
Normal - Cooling (b)	1,395	1,390	2,064	2,055

(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 2017 Compared to Third Quarter of 2016
Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Net Income
(in millions)

Third Quarter of 2016	$52.8
Changes in Gross Margin:	
Retail Margins (a)	(15.6)
Off-system Sales	(0.7)
Transmission Revenues	4.1
Other Revenues	(2.0)
Total Change in Gross Margin	(14.2)
Changes in Expenses and Other:	
Other Operation and Maintenance	(2.2)
Depreciation and Amortization	5.5
Taxes Other Than Income Taxes	(0.7)
Interest Income	(0.2)
Allowance for Equity Funds Used During Construction	(1.1)
Interest Expense	1.7
Total Change in Expenses and Other	3.0
Income Tax Expense	4.6
Third Quarter of 2017	$46.2

(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 $16 million primarily due to the following:
  - A $17 million decrease primarily due to higher rates implemented in 2016 associated with interim rates.
  - An $11 million decrease in weather-related usage primarily due to a 14% decrease in cooling degree days.

  These decreases were partially offset by:
  - A $14 million increase due to weather-normalized margins.
- Transmission Revenues increased $4 million primarily due to an accrual for SPP sponsor-funded transmission upgrades in third quarter 2016.

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

- Depreciation and Amortization expenses decreased $6 million primarily due the following:
  - A $9 million decrease primarily related to prior year higher estimated depreciation expense associated with interim rates.

  This decrease was partially offset by:
  - A $4 million increase primarily related to new depreciation rates implemented in 2017 and a higher depreciable base.

- Income Tax Expense decreased $5 million primarily due to a decrease in pretax book income.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Reconciliation of Nine Months Ended September 30, 2016 to
Nine Months Ended September 30, 2017
Net Income
(in millions)

Nine Months Ended September 30, 2016	$97.4
Changes in Gross Margin:	
Retail Margins (a)	(17.6)
Off-system Sales	(0.9)
Transmission Revenues	4.8
Other Revenues	(4.6)
Total Change in Gross Margin	(18.3)
Changes in Expenses and Other:	
Other Operation and Maintenance	(31.1)
Depreciation and Amortization	12.1
Taxes Other Than Income Taxes	(2.2)
Interest Income	(0.4)
Allowance for Equity Funds Used During Construction	(4.5)
Interest Expense	4.4
Total Change in Expenses and Other	(21.7)
Income Tax Expense	14.0
Nine Months Ended September 30, 2017	$71.4

(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 $18 million primarily due to the following:
  - A $15 million decrease in weather-related usage primarily due to an 11% decrease in cooling degree days and a 13% decrease in heating degree days.
  - A $14 million decrease primarily due to higher rates implemented in 2016 associated with interim rates.

  These decreases were partially offset by:
  - A $9 million increase primarily due to higher weather-normalized margins.
  - A $5 million increase related to new base rates implemented in January 2017.
- Transmission Revenues increased $5 million primarily due to an accrual for SPP sponsor-funded transmission upgrades in third quarter 2016 and additional transmission investments in SPP.
- Other Revenues decreased $5 million primarily due to the elimination of connection charges for certain customers with advanced metering, effective with the implementation of new base rates in January 2017.

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

- Other Operation and Maintenance expenses increased $31 million primarily due to the following:
  - A $16 million increase in vegetation management expenses. This increase is partially offset by a corresponding increase in Retail Margins as vegetation management expenses recovered in the prior year under the System Reliability Rider are now recovered as a component of base rates in the current year.
  - A $15 million increase in transmission expenses primarily due to increased SPP transmission services.
- Depreciation and Amortization expenses decreased $12 million primarily due the following:
  - A $24 million decrease primarily related to prior year higher estimated depreciation expense associated with interim rates.

  This decrease was partially offset by:
  - A $12 million increase primarily related to new depreciation rates implemented in 2017 and a higher depreciable base.
- Allowance for Equity Funds Used During Construction decreased $5 million primarily due to the completion of environmental projects.
- Interest Expense decreased $4 million primarily due to the deferral of the debt component of carrying charges on environmental control costs for projects at Northeastern Plant, Unit 3 and the Comanche Plant.
- Income Tax Expense decreased $14 million primarily due to a decrease in pretax book income.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
REVENUES				
Electric Generation, Transmission and Distribution	$440.6	$400.9	$1,085.1	$971.3
Sales to AEP Affiliates	1.1	0.1	3.2	2.0
Other Revenues	1.1	0.7	3.3	2.9
TOTAL REVENUES	442.8	401.7	1,091.6	976.2
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	77.9	16.4	115.8	43.0
Purchased Electricity for Resale	127.8	130.8	379.8	315.3
Purchased Electricity from AEP Affiliates	—	3.2	—	3.6
Other Operation	83.6	81.0	226.3	211.8
Maintenance	25.2	25.6	88.2	71.6
Depreciation and Amortization	31.7	37.2	97.8	109.9
Taxes Other Than Income Taxes	9.8	9.1	30.0	27.8
TOTAL EXPENSES	356.0	303.3	937.9	783.0
OPERATING INCOME	86.8	98.4	153.7	193.2
Other Income (Expense):				
Interest Income	—	0.2	0.1	0.5
Allowance for Equity Funds Used During Construction	—	1.1	0.4	4.9
Interest Expense	(13.2)	(14.9)	(40.2)	(44.6)
INCOME BEFORE INCOME TAX EXPENSE	73.6	84.8	114.0	154.0
Income Tax Expense	27.4	32.0	42.6	56.6
NET INCOME	$46.2	$52.8	$71.4	$97.4

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

See Condensed Notes to Condensed Financial

Statements of Registrants beginning on page 118.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net Income	$46.2	$52.8	$71.4	$97.4
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, 2017 and 2016, Respectively, and $(0.3) and $(0.3) for the Nine Months Ended September 30, 2017 and 2016, Respectively	(0.2)	(0.2)	(0.6)	(0.6)
TOTAL COMPREHENSIVE INCOME	$46.0	$52.6	$70.8	$96.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2016	$ 157.2	$ 364.0	$ 689.5	$ 3.4	$ 1,214.1
Common Stock Dividends			(52.5)		(52.5)
Net Income			71.4		71.4
Other Comprehensive Loss				(0.6)	(0.6)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2017	$ 157.2	$ 364.0	$ 708.4	$ 2.8	$ 1,232.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2017 and December 31, 2016
(in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2.1	$ 1.5
Accounts Receivable:		
Customers	17.8	27.5
Affiliated Companies	31.8	26.8
Miscellaneous	3.2	4.4
Allowance for Uncollectible Accounts	(0.1)	(0.2)
Total Accounts Receivable	52.7	58.5
Fuel	11.9	22.9
Materials and Supplies	42.1	44.6
Risk Management Assets	4.7	0.8
Accrued Tax Benefits	27.0	27.3
Regulatory Asset for Under-Recovered Fuel Costs	36.9	33.8
Prepayments and Other Current Assets	14.4	6.0
TOTAL CURRENT ASSETS	191.8	195.4
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,573.8	1,559.3
Transmission	852.5	832.8
Distribution	2,414.1	2,322.4
Other Property, Plant and Equipment	286.3	233.2
Construction Work in Progress	114.0	148.2
Total Property, Plant and Equipment	5,240.7	5,095.9
Accumulated Depreciation and Amortization	1,382.8	1,272.7
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	3,857.9	3,823.2
OTHER NONCURRENT ASSETS		
Regulatory Assets	393.6	340.2
Employee Benefits and Pension Assets	16.0	10.4
Deferred Charges and Other Noncurrent Assets	19.2	10.0
TOTAL OTHER NONCURRENT ASSETS	428.8	360.6
TOTAL ASSETS	$ 4,478.5	$ 4,379.2

See Condensed Notes to Condensed Financial Statements

of
Registrants
beginning
on page
118.

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PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2017 and December 31, 2016
(Unaudited)

	September 30, 2017	December 31, 2016
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$118.0	$ 52.0
Accounts Payable:		
General	93.8	116.3
Affiliated Companies	43.0	56.2
Long-term Debt Due Within One Year – Nonaffiliated	0.5	0.5
Customer Deposits	53.1	49.7
Accrued Taxes	40.8	21.0
Accrued Interest	19.5	13.9
Provision for Refund	4.1	46.1
Other Current Liabilities	38.5	47.8
TOTAL CURRENT LIABILITIES	411.3	403.5
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,285.9	1,285.5
Deferred Income Taxes	1,152.5	1,058.8
Regulatory Liabilities and Deferred Investment Tax Credits	320.9	339.7
Asset Retirement Obligations	54.5	52.8
Deferred Credits and Other Noncurrent Liabilities	21.0	24.8
TOTAL NONCURRENT LIABILITIES	2,834.8	2,761.6
TOTAL LIABILITIES	3,246.1	3,165.1
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	708.4	689.5
Accumulated Other Comprehensive Income (Loss)	2.8	3.4
TOTAL COMMON SHAREHOLDER'S EQUITY	1,232.4	1,214.1
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$4,478.5	$ 4,379.2

See
Condensed
Notes to

Condensed Financial Statements of Registrants beginning on page 118.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2017	2016
OPERATING ACTIVITIES		
Net Income	$ 71.4	$ 97.4
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	97.8	109.9
Deferred Income Taxes	93.7	79.5
Allowance for Equity Funds Used During Construction	(0.4)	(4.9)
Mark-to-Market of Risk Management Contracts	(3.9)	(0.7)
Pension Contributions to Qualified Plan Trust	(5.3)	(5.6)
Property Taxes	(9.4)	(8.0)
Deferred Fuel Over/Under-Recovery, Net	(5.6)	(80.2)
Provision for Refund, Net	(39.4)	13.8
Change in Other Noncurrent Assets	(19.8)	(18.8)
Change in Other Noncurrent Liabilities	(1.4)	(3.7)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	5.8	4.4
Fuel, Materials and Supplies	13.5	(2.4)
Accounts Payable	(18.5)	23.1
Accrued Taxes, Net	20.1	45.4
Other Current Assets	(8.2)	(2.2)
Other Current Liabilities	1.5	(14.9)
Net Cash Flows from Operating Activities	191.9	232.1
INVESTING ACTIVITIES		
Construction Expenditures	(203.1)	(266.8)
Change in Advances to Affiliates, Net	—	29.5
Other Investing Activities	1.5	8.7
Net Cash Flows Used for Investing Activities	(201.6)	(228.6)

FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	—	150.0
Change in Advances from Affiliates, Net	66.0	—
Retirement of Long-term Debt – Nonaffiliated	(0.3)	(150.3)
Principal Payments for Capital Lease Obligations	(3.2)	(3.0)
Dividends Paid on Common Stock	(52.5)	—
Other Financing Activities	0.3	0.4
Net Cash Flows from (Used for) Financing Activities	10.3	(2.9)
Net Increase in Cash and Cash Equivalents	0.6	0.6
Cash and Cash Equivalents at Beginning of Period	1.5	1.4
Cash and Cash Equivalents at End of Period	$ 2.1	$ 2.0
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 40.9	$ 45.0
Net Cash Paid (Received) for Income Taxes	(46.6)	(50.3)
Noncash Acquisitions Under Capital Leases	1.0	2.2
Construction Expenditures Included in Current Liabilities as of September 30,	15.1	20.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

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,	
	2017	2016	2017	2016
	(in millions of KWhs)			
Retail:				
Residential	1,887	2,105	4,547	4,879
Commercial	1,677	1,793	4,466	4,652
Industrial	1,339	1,254	3,895	3,830
Miscellaneous	19	20	60	61
Total Retail	4,922	5,172	12,968	13,422
Wholesale	2,105	2,326	6,286	6,056
Total KWhs	7,027	7,498	19,254	19,478

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,	
	2017	2016	2017	2016
	(in degree days)			
Actual - Heating (a)	—	—	394	586
Normal - Heating (b)	1	1	747	747
Actual - Cooling (c)	1,248	1,502	1,999	2,277
Normal - Cooling (b)	1,414	1,410	2,185	2,177

(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.

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Third Quarter of 2017 Compared to Third Quarter of 2016
Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Third Quarter of 2016	$83.3
Changes in Gross Margin:	
Retail Margins (a)	(6.9)
Off-system Sales	0.1
Transmission Revenues	(8.0)
Other Revenues	(0.1)
Total Change in Gross Margin	(14.9)
Changes in Expenses and Other:	
Other Operation and Maintenance	10.1
Depreciation and Amortization	(4.0)
Taxes Other Than Income Taxes	(1.6)
Interest Income	0.7
Allowance for Equity Funds Used During Construction	0.3
Interest Expense	0.7
Total Change in Expenses and Other	6.2
Income Tax Expense	10.7
Equity Earnings (Loss) of Unconsolidated Subsidiary	(2.3)
Net Income Attributable to Noncontrolling Interest	(9.9)
Third Quarter of 2017	$73.1

(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 $7 million primarily due to the following:
  - An $18 million decrease in weather-related usage due to a 17% decrease in cooling degree days.

  This decrease was partially offset by:
  - An $11 million increase due to rider revenue increases in Louisiana, partially offset in expense items below.
- Transmission Revenues decreased $8 million primarily due to an accrual for SPP sponsor-funded transmission upgrades in third quarter 2016. This decrease is offset by a corresponding decrease in Other Operation and Maintenance expenses below.

Expenses and Other, Income Tax Expense and Net Income Attributable to Noncontrolling Interest changed between years as follows:

- Other Operation and Maintenance expenses decreased $10 million primarily due to a $12 million accrual for SPP sponsor-funded transmission upgrades in third quarter 2016. This decrease is partially offset by a corresponding decrease in Transmission Revenues above.

- Depreciation and Amortization expenses increased $4 million primarily due to a higher depreciable base.
- Income Tax Expense decreased $11 million primarily due to income tax benefits attributable to SWEPCo’s noncontrolling interest in Sabine. This decrease is offset by an increase in Net Income Attributable to Noncontrolling Interest below.
- Net Income Attributable to Noncontrolling Interest increased $10 million primarily due to income tax benefits attributable to SWEPCo’s noncontrolling interest in Sabine. This increase is offset by a decrease in Income Tax Expense above.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Reconciliation of Nine Months Ended September 30, 2016 to Nine Months Ended September 30, 2017
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Nine Months Ended September 30, 2016	$ 149.9
Changes in Gross Margin:	
Retail Margins (a)	(8.4)
Off-system Sales	3.8
Transmission Revenues	(5.5)
Other Revenues	0.3
Total Change in Gross Margin	(9.8)
Changes in Expenses and Other:	
Other Operation and Maintenance	6.6
Depreciation and Amortization	(10.0)
Taxes Other Than Income Taxes	(5.8)
Interest Income	2.0
Allowance For Equity Funds Used During Construction	(8.3)
Interest Expense	(0.7)
Total Change in Expenses and Other	(16.2)
Income Tax Expense	8.7
Equity Earnings (Loss) of Unconsolidated Subsidiary	(9.4)
Net Income Attributable to Noncontrolling Interest	(9.3)
Nine Months Ended September 30, 2017	$ 113.9

(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 $8 million primarily due to the following:
- A $29 million decrease in weather-related usage primarily due to a 33% decrease in heating degree days and a 12% decrease in cooling degree days.
- A $9 million decrease in FERC generation wholesale municipal and cooperative revenues due to an annual formula rate true-up.
- A $3 million decrease primarily due to lower fuel cost recovery.

These decreases were partially offset by:

- A $33 million increase due to rider revenue increases in Louisiana, Texas and Arkansas, partially offset in various expenses below.
- Margins from Off-System Sales increased $4 million primarily due to higher sales prices.
- Transmission Revenues decreased $6 million primarily due to an accrual for SPP sponsor-funded transmission upgrades in third quarter 2016. This decrease is offset by a corresponding decrease in Other Operation and Maintenance expenses below.

Expenses and Other, Income Tax Expense, Equity Earnings (Loss) of Unconsolidated Subsidiary and Net Income Attributable to Noncontrolling Interest changed between years as follows:

- Other Operation and Maintenance expenses decreased $7 million primarily due to an accrual for SPP sponsor-funded transmission upgrades in third quarter 2016. This decrease is partially offset by a corresponding decrease in Transmission Revenues above.
- Depreciation and Amortization expenses increased $10 million primarily due to a higher depreciable base.
- Taxes Other than Income Taxes increased $6 million primarily due to an increase in property taxes.
- Allowance for Equity Funds Used During Construction decreased $8 million primarily due to the completion of environmental projects.
- Income Tax Expense decreased $9 million primarily due to income tax benefits attributable to SWEPCo's noncontrolling interest in Sabine. This decrease is offset by an increase in Net Income Attributable to Noncontrolling Interest below.
- Equity Earnings (Loss) of Unconsolidated Subsidiary decreased $9 million primarily due to a prior period income tax adjustment for DHLC.
- Net Income Attributable to Noncontrolling Interest increased $9 million primarily due to income tax benefits attributable to SWEPCo's noncontrolling interest in Sabine. This increase is offset by a decrease in Income Tax Expense above.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
REVENUES				
Electric Generation, Transmission and Distribution	$509.5	$530.5	$1,321.8	$1,324.1
Sales to AEP Affiliates	7.7	8.6	20.4	20.0
Other Revenues	0.4	0.6	1.4	1.6
TOTAL REVENUES	517.6	539.7	1,343.6	1,345.7
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	147.5	158.8	389.8	403.3
Purchased Electricity for Resale	40.0	35.9	118.7	97.5
Other Operation	80.3	89.2	232.2	243.3
Maintenance	32.6	33.8	106.5	102.0
Depreciation and Amortization	55.2	51.2	158.1	148.1
Taxes Other Than Income Taxes	25.0	23.4	72.6	66.8
TOTAL EXPENSES	380.6	392.3	1,077.9	1,061.0
OPERATING INCOME	137.0	147.4	265.7	284.7
Other Income (Expense):				
Interest Income	0.7	—	2.0	—
Allowance for Equity Funds Used During Construction	0.4	0.1	1.2	9.5
Interest Expense	(31.9)	(32.6)	(92.7)	(92.0)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS (LOSS)	106.2	114.9	176.2	202.2
Income Tax Expense	22.5	33.2	45.2	53.9
Equity Earnings (Loss) of Unconsolidated Subsidiary	0.4	2.7	(4.5)	4.9
NET INCOME	84.1	84.4	126.5	153.2
Net Income Attributable to Noncontrolling Interest	11.0	1.1	12.6	3.3
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$73.1	$83.3	$113.9	$149.9

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net Income	$84.1	$84.4	$126.5	$153.2
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, 2017 and 2016, Respectively, and $0.6 and $0.7 for the Nine Months Ended September 30, 2017 and 2016, Respectively	0.4	0.4	1.1	1.3
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended September 30, 2017 and 2016, Respectively, and $(0.3) and $(0.3) for the Nine Months Ended September 30, 2017 and 2016, Respectively	(0.2)	(0.1)	(0.5)	(0.5)
TOTAL OTHER COMPREHENSIVE INCOME	0.2	0.3	0.6	0.8
TOTAL COMPREHENSIVE INCOME	84.3	84.7	127.1	154.0
Total Comprehensive Income Attributable to Noncontrolling Interest	11.0	1.1	12.6	3.3
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$73.3	$83.6	$114.5	$150.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2017 and 2016
(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, 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
TOTAL EQUITY - DECEMBER 31, 2016	$135.7	$676.6	$1,411.9	$ (9.4)	$ 0.4	$2,215.2
Common Stock Dividends			(82.5)			(82.5)
Common Stock Dividends – Nonaffiliated					(2.7)	(2.7)
Net Income			113.9		12.6	126.5
Other Comprehensive Income				0.6		0.6
TOTAL EQUITY - SEPTEMBER 30, 2017	$135.7	$676.6	$1,443.3	$ (8.8)	$ 10.3	$2,257.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2017 and December 31, 2016
(in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents (September 30, 2017 and December 31, 2016 Amounts Include $0 and $8.7, Respectively, Related to Sabine)	$ 2.2	$ 10.3
Advances to Affiliates	2.0	169.8
Accounts Receivable:		
Customers	23.5	48.5
Affiliated Companies	37.6	29.3
Miscellaneous	20.8	17.5
Allowance for Uncollectible Accounts	(1.5)	(1.2)
Total Accounts Receivable	80.4	94.1
Fuel (September 30, 2017 and December 31, 2016 Amounts Include $43.2 and $34.3, Respectively, Related to Sabine)	93.1	107.1
Materials and Supplies	68.8	68.4
Risk Management Assets	12.5	0.9
Accrued Tax Benefits	14.5	51.5
Regulatory Asset for Under-Recovered Fuel Costs	13.6	8.4
Prepayments and Other Current Assets	35.5	35.5
TOTAL CURRENT ASSETS	322.6	546.0
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,632.9	4,607.6
Transmission	1,656.4	1,584.2
Distribution	2,084.2	2,020.6
Other Property, Plant and Equipment (September 30, 2017 and December 31, 2016 Amounts Include $266.6 and $267.5, Respectively, Related to Sabine)	701.6	670.4
Construction Work in Progress	145.2	113.8
Total Property, Plant and Equipment	9,220.3	8,996.6
Accumulated Depreciation and Amortization (September 30, 2017 and December 31, 2016 Amounts Include $162.8 and $155.6, Respectively, Related to Sabine)	2,670.5	2,567.1
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,549.8	6,429.5
OTHER NONCURRENT ASSETS		
Regulatory Assets	566.4	551.2
Long-term Risk Management Assets	0.7	—
Deferred Charges and Other Noncurrent Assets	116.4	99.9

TOTAL OTHER NONCURRENT ASSETS	683.5	651.1
TOTAL ASSETS	$7,555.9	$ 7,626.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2017 and December 31, 2016
(Unaudited)

	September 30, 2017	December 31, 2016
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$48.3	$ —
Accounts Payable:		
General	120.9	117.5
Affiliated Companies	38.5	68.5
Short-term Debt – Nonaffiliated	14.3	—
Long-term Debt Due Within One Year – Nonaffiliated	385.4	353.7
Risk Management Liabilities	0.1	0.3
Customer Deposits	61.6	62.1
Accrued Taxes	73.0	40.9
Accrued Interest	25.1	45.1
Obligations Under Capital Leases	11.4	11.8
Other Current Liabilities	77.5	83.9
TOTAL CURRENT LIABILITIES	856.1	783.8
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,056.1	2,325.4
Deferred Income Taxes	1,694.5	1,606.9
Regulatory Liabilities and Deferred Investment Tax Credits	441.3	438.9
Asset Retirement Obligations	159.0	147.1
Employee Benefits and Pension Obligations	19.9	34.1
Obligations Under Capital Leases	60.2	65.5
Deferred Credits and Other Noncurrent Liabilities	11.7	9.7
TOTAL NONCURRENT LIABILITIES	4,442.7	4,627.6
TOTAL LIABILITIES	5,298.8	5,411.4
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	1,443.3	1,411.9
Accumulated Other Comprehensive Income (Loss)	(8.8)	(9.4)
TOTAL COMMON SHAREHOLDER’S EQUITY	2,246.8	2,214.8
Noncontrolling Interest	10.3	0.4

TOTAL EQUITY	2,257.1	2,215.2
TOTAL LIABILITIES AND EQUITY	$7,555.9	$ 7,626.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Nine Months Ended September 30,					
	2017			2016		
OPERATING ACTIVITIES						
Net Income	$	126.5		$	153.2	
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:						
Depreciation and Amortization	158.1			148.1		
Deferred Income Taxes	79.8			141.9		
Allowance for Equity Funds Used During Construction	(1.2		)	(9.5		)
Mark-to-Market of Risk Management Contracts	(12.5		)	(5.8		)
Pension Contributions to Qualified Plan Trust	(8.9		)	(8.3		)
Property Taxes	(15.4		)	(13.7		)
Deferred Fuel Over/Under-Recovery, Net	2.4			1.2		
Change in Other Noncurrent Assets	(2.9		)	18.4		
Change in Other Noncurrent Liabilities	(5.2		)	(25.8		)
Changes in Certain Components of Working Capital:						
Accounts Receivable, Net	12.1			12.2		
Fuel, Materials and Supplies	13.6			33.4		
Accounts Payable	(25.7		)	(17.2		)
Accrued Taxes, Net	69.1			14.1		
Accrued Interest	(20.0		)	(20.0		)
Other Current Assets	0.7			(2.4		)
Other Current Liabilities	(14.6		)	(24.8		)
Net Cash Flows from Operating Activities	355.9			395.0		
INVESTING ACTIVITIES						
Construction Expenditures	(265.3		)	(315.3		)
Change in Advances to Affiliates, Net	167.8			(297.4		)
Other Investing Activities	3.1			(1.9		)
Net Cash Flows Used for Investing Activities	(94.4		)	(614.6		)

FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	114.6	402.2
Change in Short-term Debt – Nonaffiliated	14.3	—
Change in Advances from Affiliates, Net	48.3	(58.3)
Retirement of Long-term Debt – Nonaffiliated	(353.6)	(3.3)
Principal Payments for Capital Lease Obligations	(8.4)	(18.6)
Dividends Paid on Common Stock	(82.5)	(90.0)
Dividends Paid on Common Stock – Nonaffiliated	(2.7)	(3.5)
Other Financing Activities	0.4	1.1
Net Cash Flows from (Used for) Financing Activities	(269.6)	229.6
Net Increase (Decrease) in Cash and Cash Equivalents	(8.1)	10.0
Cash and Cash Equivalents at Beginning of Period	10.3	5.2
Cash and Cash Equivalents at End of Period	$ 2.2	$ 15.2
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 109.4	$ 107.6
Net Cash Paid (Received) for Income Taxes	(70.5)	(66.6)
Noncash Acquisitions Under Capital Leases	2.8	5.5
Construction Expenditures Included in Current Liabilities as of September 30,	40.7	54.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

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, 2017 is not necessarily indicative of results that may be expected for the year ending December 31, 2017. The condensed financial statements are unaudited and should be read in conjunction with the audited 2016 financial statements and notes thereto, which are included in the Registrants (except AEPTCo) Annual Reports on Form 10-K as filed with the SEC on February 27, 2017. AEPTCo should be read in conjunction with the audited 2016 financial statements and notes thereto, which are included on Form S-4 as filed with the SEC on April 5, 2017.

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 income:

	Three Months Ended September 30,			
	2017		2016	
	(in millions, except per share data)			
		$/share		$/share
Income (Loss) from Continuing Operations	$556.7		$(764.2)	
Less: Net Income Attributable to Noncontrolling Interests	12.0		1.6	
Earnings (Loss) Attributable to AEP Common Shareholders from Continuing Operations	$544.7		$(765.8)	
Weighted Average Number of Basic Shares Outstanding	491.8	$1.11	491.7	$(1.56)
Weighted Average Dilutive Effect of Stock-Based Awards	1.2	(0.01)	0.1	—
Weighted Average Number of Diluted Shares Outstanding	493.0	$1.10	491.8	$(1.56)

	Nine Months Ended September 30,			
	2017		2016	
	(in millions, except per share data)			
		$/share		$/share
Income from Continuing Operations	$1,527.1		$245.3	
Less: Net Income Attributable to Noncontrolling Interests	15.2		5.3	

Earnings Attributable to AEP Common Shareholders from Continuing Operations	$1,511.9		$240.0	
Weighted Average Number of Basic Shares Outstanding	491.8	$ 3.07	491.4	$ 0.49
Weighted Average Dilutive Effect of Stock-Based Awards	0.6	—	0.2	—
Weighted Average Number of Diluted Shares Outstanding	492.4	$ 3.07	491.6	$ 0.49

There were no antidilutive shares outstanding as of September 30, 2017 and 2016.

Nonconsolidated Variable Interest Entity (Applies to AEP and SWEPCo)

SWEPCo recorded prior year income tax adjustments in the second quarter of 2017 related to DHLC that impacted Equity Earnings (Loss) of Unconsolidated Subsidiary in the amount of $6 million.

Supplementary Cash Flow Information (Applies to AEP)

Cash Flow Information	Nine Months Ended September 30, 2017	2016
	(in millions)	
Cash Paid (Received) for:		
Interest, Net of Capitalized Amounts	$613.8	$637.0
Income Taxes, Net	(6.8)	32.2
Noncash Investing and Financing Activities:		
Acquisitions Under Capital Leases	44.5	65.8
Construction Expenditures Included in Current Liabilities as of September 30,	791.6	604.8
Construction Expenditures Included in Noncurrent Liabilities as of September 30,	71.8	—
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	0.6	0.3
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	2.8	—

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 with early adoption permitted.

Management continues to analyze the impact of the new revenue standard and related ASUs. During 2016 and 2017, revenue contract assessments were completed. Material revenue streams were identified within the AEP System and representative contract/transaction types were sampled. Performance obligations identified within each material revenue stream were evaluated to determine whether the obligations were satisfied at a point in time or over time. Contracts determined to be satisfied over time generally qualified for the invoicing practical expedient since the invoiced amounts reasonably represented the value to customers of performance obligations fulfilled to date. Based upon the completed assessments, management does not expect a material impact to the timing of revenue recognized or net income and plans to elect the modified retrospective transition approach upon adoption.

The evaluation of revenue streams, new contracts and the new revenue standard's disclosure requirements continues during the fourth quarter of 2017, in particular with respect to various ongoing industry implementation issues. Management will continue to analyze the related impacts to revenue recognition and monitor any new industry implementation issues that arise. Further, given industry conclusions related to implementation issues, including contributions in aid of construction and collectability, management does not anticipate changes to current accounting systems. Management plans to adopt ASU 2014-09 effective January 1, 2018.

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 sheets 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.

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 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.

Management continues to analyze the impact of the new lease standard. During 2016 and 2017, lease contract assessments were completed. The AEP System lease population was identified and representative lease contracts were sampled. Based upon the completed assessments, management prepared a system gap analysis to outline new disclosure compliance requirements compared to current system capabilities. Multiple lease system options were also evaluated. Management plans to elect certain of the following practical expedients upon adoption:

Practical Expedient	Description
Overall Expedients (for leases commenced prior to adoption date and must be adopted as a package)	Do not need to reassess whether any expired or existing contracts are/or contain leases, do not need to reassess the lease classification for any expired or existing leases and do not need to reassess initial direct costs for any existing leases.
Lease and Non-lease Components (elect by class of underlying asset)	Elect as an accounting policy to not separate non-lease components from lease components and instead account for each lease and associated non-lease component as a single lease component.
Short-term Lease (elect by class of underlying asset)	Elect as an accounting policy to not apply the recognition requirements to short-term leases.
Lease term	Elect to use hindsight to determine the lease term.

Evaluation of new lease contracts continues and the process of implementing a compliant lease system solution began in the third quarter of 2017. Management expects the new standard to impact financial position, but not results of operations or cash flows. Management also continues to monitor unresolved industry implementation issues, including items related to pole attachments, easements and right-of-ways, and will analyze the related impacts to lease accounting. 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.

Management adopted ASU 2016-09 effective January 1, 2017. As a result of the adoption of this guidance, management made an accounting policy election to recognize the effect of forfeitures in compensation cost when they occur. There was an immaterial impact on results of operations and financial position and no impact on cash flows at adoption.

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.

ASU 2016-18 “Restricted Cash” (ASU 2016-18)

In November 2016, the FASB issued ASU 2016-18 clarifying the treatment of restricted cash on the statements of cash flows. Under the new standard, amounts considered restricted cash will be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts on the statements of cash flows.

The new accounting guidance is effective for annual periods beginning after December 15, 2017. Early adoption is permitted in any interim or annual period. The guidance will be applied by means of a retrospective approach. Management is analyzing the impact of the new standard. Management plans to adopt ASU 2016-18 effective for the 2017 Annual Report.

ASU 2017-07 “Compensation - Retirement Benefits” (ASU 2017-07)

In March 2017, the FASB issued ASU 2017-07 requiring that an employer report the service cost component of pension and postretirement benefits in the same line item or items as other compensation costs. The other components of net benefit cost are required to be presented in the statements of income separately from the service cost component and outside of a subtotal of income from operations. In addition, only the service cost component will be eligible for capitalization as applicable following labor. For 2016, AEP’s actual non-service cost components were a credit of $66 million, of which approximately 37% was capitalized.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted as of the beginning of an annual period for which financial statements have not been issued or made available for issuance. Management plans to adopt ASU 2017-07 effective January 1, 2018.

ASU 2017-12 “Derivatives and Hedging” (ASU 2017-12)

In August 2017, the FASB issued ASU 2017-12 amending the recognition and presentation requirements for hedge accounting activities. The objectives are to improve the financial reporting of hedging relationships to better portray the economic results of an entity’s risk management activities in its financial statements and reduce the complexity of applying hedge accounting. Under the new standard, the concept of recognizing hedge ineffectiveness within the statements of income for cash flow hedges, which has historically been immaterial to AEP, will be eliminated. In addition, certain required tabular disclosures relating to fair value and cash flow hedges will be modified.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2018 with early adoption permitted for any interim or annual period after August 2017. Management is analyzing the impact of this new standard, including the possibility of early adoption, and at this time, cannot estimate the impact of adoption on net income.

3. COMPREHENSIVE INCOME

The disclosures in this note apply to all Registrants except for AEPTCo. AEPTCo does not have any components of other comprehensive income for any period presented in the condensed financial statements.

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, 2017 and 2016. 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, 2017

	Cash Flow Hedges				
	Commodity	Interest Rate	Securities Available for Sale	Pension and OPEB	Total
	(in millions)				
Balance in AOCI as of June 30, 2017	$(36.0)	$(10.4)	$ 10.2	$(125.4)	$(161.6)
Change in Fair Value Recognized in AOCI	(15.8)	(2.0)	0.9	—	(16.9)
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues	(0.9)	—	—	—	(0.9)
Purchased Electricity for Resale	4.9	—	—	—	4.9
Interest Expense	—	0.4	—	—	0.4
Amortization of Prior Service Cost (Credit)	—	—	—	(5.0)	(5.0)
Amortization of Actuarial (Gains)/Losses	—	—	—	5.4	5.4
Reclassifications from AOCI, before Income Tax (Expense) Credit	4.0	0.4	—	0.4	4.8
Income Tax (Expense) Credit	1.4	0.2	—	0.1	1.7
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	2.6	0.2	—	0.3	3.1
Net Current Period Other Comprehensive Income (Loss)	(13.2)	(1.8)	0.9	0.3	(13.8)
Balance in AOCI as of September 30, 2017	$(49.2)	$(12.2)	$ 11.1	$(125.1)	$(175.4)

AEP

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

	Cash Flow Hedges				
	Commodity	Interest Rate	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 Nine Months Ended September 30, 2017

	Cash Flow Hedges				
	Commodity	Interest Rate	Securities Available for Sale	Pension and OPEB	Total
	(in millions)				
Balance in AOCI as of December 31, 2016	$(23.1)	$(15.7)	$ 8.4	$(125.9)	$(156.3)
Change in Fair Value Recognized in AOCI	(39.4)	2.7	2.7	—	(34.0)
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues	(5.6)	—	—	—	(5.6)
Purchased Electricity for Resale	26.0	—	—	—	26.0
Interest Expense	—	1.2	—	—	1.2
Amortization of Prior Service Cost (Credit)	—	—	—	(14.8)	(14.8)
Amortization of Actuarial (Gains)/Losses	—	—	—	16.0	16.0
Reclassifications from AOCI, before Income Tax (Expense) Credit	20.4	1.2	—	1.2	22.8
Income Tax (Expense) Credit	7.1	0.4	—	0.4	7.9
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	13.3	0.8	—	0.8	14.9
Net Current Period Other Comprehensive Income (Loss)	(26.1)	3.5	2.7	0.8	(19.1)
Balance in AOCI as of September 30, 2017	$(49.2)	$(12.2)	$ 11.1	$(125.1)	$(175.4)

AEP

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

	Cash Flow Hedges				
	Commodity	Interest Rate	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)

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2017

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2017	$2.5	$(11.9)	$(9.4)
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)	—	(1.4)	(1.4)
Amortization of Actuarial (Gains)/Losses	—	0.9	0.9
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.2)	(0.5)	(0.7)
Income Tax (Expense) Credit	(0.1)	(0.2)	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.1)	(0.3)	(0.4)
Net Current Period Other Comprehensive Loss	(0.1)	(0.3)	(0.4)
Balance in AOCI as of September 30, 2017	$2.4	$(12.2)	$(9.8)

APCo

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

	Cash Flow Hedges		
	Interest Rate	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 Nine Months Ended September 30, 2017

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2016	$2.9	$(11.3)	$(8.4)
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)	—	(4.0)	(4.0)
Amortization of Actuarial (Gains)/Losses	—	2.6	2.6
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.8)	(1.4)	(2.2)
Income Tax (Expense) Credit	(0.3)	(0.5)	(0.8)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.5)	(0.9)	(1.4)
Net Current Period Other Comprehensive Loss	(0.5)	(0.9)	(1.4)
Balance in AOCI as of September 30, 2017	$2.4	$(12.2)	$(9.8)

APCo

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

	Cash Flow Hedges		
	Interest Rate	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)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2017

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2017	$(11.3)	$(4.2)	$(15.5)
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)	—	(0.3)	(0.3)
Amortization of Actuarial (Gains)/Losses	—	0.3	0.3
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, 2017	$(11.0)	$(4.2)	$(15.2)

I&M

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

	Cash Flow Hedges		
	Interest Rate	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 Nine Months Ended September 30, 2017

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2016	$(12.0)	$(4.2)	$(16.2)
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)	—	(0.7)	(0.7)
Amortization of Actuarial (Gains)/Losses	—	0.7	0.7
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, 2017	$(11.0)	$(4.2)	$(15.2)

I&M

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

	Cash Flow Hedges		
	Interest Rate	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)

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2017

	Cash Flow Hedges Interest Rate (in millions)
Balance in AOCI as of June 30, 2017	$ 2.5
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, 2017	$ 2.2

OPCo

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

	Cash Flow Hedges Interest Rate (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 Nine Months Ended September 30, 2017

	Cash Flow Hedges Interest Rate (in millions)
Balance in AOCI as of December 31, 2016	$ 3.0
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1.3)
Income Tax (Expense) Credit	(0.5)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.8)
Net Current Period Other Comprehensive Loss	(0.8)
Balance in AOCI as of September 30, 2017	$ 2.2

OPCo

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

	Cash Flow Hedges Interest Rate (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

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2017

	Cash Flow Hedges Interest Rate (in millions)
Balance in AOCI as of June 30, 2017	$ 3.0
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(0.4)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.4)
Income Tax (Expense) Credit	(0.2)
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, 2017	$ 2.8

PSO

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

	Cash Flow Hedges Interest Rate (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 Nine Months Ended September 30, 2017

	Cash Flow Hedges Interest Rate (in millions)
Balance in AOCI as of December 31, 2016	$ 3.4
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(1.0)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1.0)
Income Tax (Expense) Credit	(0.4)
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, 2017	$ 2.8

PSO

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

	Cash Flow Hedges Interest Rate (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

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2017

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2017	$(6.7)	$ (2.3)	$(9.0)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	0.6	—	0.6
Amortization of Prior Service Cost (Credit)	—	(0.5)	(0.5)
Amortization of Actuarial (Gains)/Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.6	(0.3)	0.3
Income Tax (Expense) Credit	0.2	(0.1)	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, 2017	$(6.3)	$ (2.5)	$(8.8)

SWEPCo

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

	Cash Flow Hedges		
	Interest Rate	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 Nine Months Ended September 30, 2017

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2016	$(7.4)	$(2.0)	$(9.4)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	1.7	—	1.7
Amortization of Prior Service Cost (Credit)	—	(1.5)	(1.5)
Amortization of Actuarial (Gains)/Losses	—	0.7	0.7
Reclassifications from AOCI, before Income Tax (Expense) Credit	1.7	(0.8)	0.9
Income Tax (Expense) Credit	0.6	(0.3)	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1.1	(0.5)	0.6
Net Current Period Other Comprehensive Income (Loss)	1.1	(0.5)	0.6
Balance in AOCI as of September 30, 2017	$(6.3)	$(2.5)	$(8.8)

SWEPCo

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

	Cash Flow Hedges		
	Interest Rate	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)

4. RATE MATTERS

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

As discussed in AEP’s and AEPTCo’s 2016 Annual Reports, the Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within AEP’s and AEPTCo’s 2016 Annual Reports 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 2017 and updates AEP’s and AEPTCo’s 2016 Annual Reports.

Regulatory Assets Pending Final Regulatory Approval

	AEP	
	September 30, 2017	December 31, 2016
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs - Unrecovered Plant (a)	$209.1	$ 159.9
Storm-Related Costs	97.4	25.1
Plant Retirement Costs - Materials and Supplies	9.1	9.1
Ohio Capacity Deferral	—	96.7
Other Regulatory Assets Pending Final Regulatory Approval	1.1	1.3
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	42.6	25.9
Plant Retirement Costs - Asset Retirement Obligation Costs	37.2	29.6
Cook Plant Uprate Project	36.3	36.3
Environmental Control Projects	24.3	24.1
Cook Plant Turbine	15.1	12.8
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	13.0	8.1
Other Regulatory Assets Pending Final Regulatory Approval	25.6	21.2
Total Regulatory Assets Pending Final Regulatory Approval (b)	$510.8	$ 450.1

(a) In March 2017, $41 million was reclassified from accumulated depreciation to regulatory assets related to Northeastern Plant, Unit 3. As of September 30, 2017, the unrecovered plant balance related to Northeastern Plant, Unit 3 was $52 million.

(b) In 2015, APCo recorded a $91 million reduction to accumulated depreciation related to the remaining net book value of plants retired in 2015, primarily in its Virginia jurisdiction. These plants were normal retirements at the end of their depreciable lives under the group composite method of depreciation. Recovery of the remaining Virginia net book value for the retired plants will be considered in APCo’s next depreciation study. The Virginia SCC staff has requested that the company prepare a depreciation study as of December 31, 2017 and submit that study to the Virginia SCC staff in 2018.

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	APCo	
Noncurrent Regulatory Assets	September 30, 2017	December 31, 2016
	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs - Materials and Supplies	$9.1	$ 9.1
Regulatory Assets Currently Not Earning a Return		
Plant Retirement Costs - Asset Retirement Obligation Costs	37.2	29.6
Other Regulatory Assets Pending Final Regulatory Approval	0.6	0.6
Total Regulatory Assets Pending Final Regulatory Approval (a)	$46.9	$ 39.3

(a) In 2015, APCo recorded a $91 million reduction to accumulated depreciation related to the remaining net book value of plants retired in 2015, primarily in its Virginia jurisdiction. These plants were normal retirements at the end of their depreciable lives under the group composite method of depreciation. Recovery of the remaining Virginia net book value for the retired plants will be considered in APCo's next depreciation study. The Virginia SCC staff has requested that the company prepare a depreciation study as of December 31, 2017 and submit that study to the Virginia SCC staff in 2018.

	I&M	
Noncurrent Regulatory Assets	September 30, 2017	December 31, 2016
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Cook Plant Uprate Project	$36.3	$ 36.3
Cook Plant Turbine	15.1	12.8
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	13.0	8.1
Rockport Dry Sorbent Injection System - Indiana	9.4	6.6
Other Regulatory Assets Pending Final Regulatory Approval	1.5	0.9
Total Regulatory Assets Pending Final Regulatory Approval	$75.3	$ 64.7

	OPCo	
Noncurrent Regulatory Assets	September 30, 2017	December 31, 2016
	(in millions)	
Regulatory Assets Currently Earning a Return		
Capacity Deferral	$—	$ 96.7
Regulatory Assets Currently Not Earning a Return		
Smart Grid Costs	—	4.1
Total Regulatory Assets Pending Final Regulatory Approval	$—	$ 100.8

	PSO	
Noncurrent Regulatory Assets	September 30, 2017	December 31, 2016
	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs - Unrecovered Plant (a)	$133.7	$ 84.5
Other Regulatory Assets Pending Final Regulatory Approval	0.5	0.5
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	36.7	20.0
Environmental Control Projects	24.3	13.1
Other Regulatory Assets Pending Final Regulatory Approval	0.4	—
Total Regulatory Assets Pending Final Regulatory Approval	$195.6	$ 118.1

(a) In March 2017, $41 million was reclassified from accumulated depreciation to regulatory assets related to Northeastern Plant, Unit 3. As of September 30, 2017, the unrecovered plant balance related to Northeastern Plant, Unit 3 was $52 million.

	SWEPCo	
Noncurrent Regulatory Assets	September 30, 2017	December 31, 2016
	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs - Unrecovered Plant	$75.4	$ 75.4
Other Regulatory Assets Pending Final Regulatory Approval	0.5	0.8
Regulatory Assets Currently Not Earning a Return		
Rate Case Expense - Texas	4.1	1.0
Asset Retirement Obligation - Arkansas, Louisiana	3.6	2.7
Shipe Road Transmission Project - FERC	3.3	3.1
Environmental Control Projects	—	11.0
Other Regulatory Assets Pending Final Regulatory Approval	2.4	1.9
Total Regulatory Assets Pending Final Regulatory Approval	$89.3	$ 95.9

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

AEP Texas Rate Matters (Applies to AEP)

AEP Texas Interim Transmission and Distribution Rates

As of September 30, 2017, AEP Texas' cumulative revenues from interim base rate increases from 2008 through 2017, subject to review, are estimated to be $697 million. A base rate review could produce a refund if AEP Texas incurs a disallowance of the transmission or distribution investment on which an interim increase was based. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring. A revenue decrease, including a refund of interim transmission and distribution rates, could reduce future net income and cash flows and impact financial condition.

Hurricane Harvey

In August 2017, Hurricane Harvey hit the coast of Texas, causing power outages in the AEP Texas service territory. AEP Texas has a PUCT approved catastrophe reserve in base rates and can defer incremental storm expenses. AEP Texas currently recovers approximately $1 million of storm costs annually through base rates. As of September 30, 2017, the total balance of AEP Texas' deferred storm costs is approximately $97 million including approximately $73 million of incremental storm expenses as a regulatory asset related to Hurricane Harvey. Management is currently in the early stages of analyzing the impact of potential insurance claims and recoveries and, at this time, cannot estimate this amount. Any future insurance recoveries received will be applied to and will offset the regulatory asset and property, plant and equipment, as applicable. AEP Texas is currently evaluating recovery options for the regulatory asset; however, management believes the asset is probable of recovery. The other named hurricanes did not have a material impact on AEP's operations in the third quarter of 2017. If the ultimate costs of the incident are not recovered by insurance or through the regulatory process, it would have an adverse effect on future net income, cash flows and financial condition.

APCo Rate Matters (Applies to AEP and APCo)

Virginia Legislation Affecting Biennial Reviews

In 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 from 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 2016, the Virginia SCC issued an order that denied the petition of certain APCo industrial customers that requested the issuance of a declaratory order that would find the amendments to Virginia law suspending biennial reviews unconstitutional and, accordingly, direct APCo to make biennial review filings beginning in 2016. In July 2016, the industrial customers filed an appeal of the order with the Supreme Court of Virginia. In September 2017, the Supreme Court of Virginia affirmed the Virginia SCC's 2016 order.

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. Through September 30, 2017, AEP's share of ETT's cumulative revenues that are subject to review is estimated to be $709 million. 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, if any, 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)

2017 Indiana Base Rate Case

In July 2017, I&M filed a request with the IURC for a $263 million annual increase in Indiana rates based upon a proposed 10.6% return on common equity with the annual increase to be implemented after June 2018. Upon implementation, this proposed annual increase would be subject to a temporary offsetting $23 million annual reduction to customer bills through December 2018 for a credit adjustment rider related to the timing of estimated in-service dates of certain capital expenditures. The proposed annual increase includes $78 million related to increased annual depreciation rates and an $11 million increase related to the amortization of certain Cook Plant and Rockport Plant regulatory assets. The increase in depreciation rates includes a change in the expected retirement date for Rockport Plant, Unit 1 from 2044 to 2028 combined with increased investment at the Cook Plant, including the Cook Plant Life Cycle Management Project. A hearing at the IURC is scheduled for January 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2017 Michigan Base Rate Case

In May 2017, I&M filed a request with the MPSC for a $52 million annual increase in Michigan base rates based upon a proposed 10.6% return on common equity with the increase to be implemented no later than April 2018. The proposed annual increase includes $23 million related to increased annual depreciation rates and a $4 million increase related to the amortization of certain Cook Plant regulatory assets. The increase in depreciation rates is primarily due to the proposed change in the expected retirement date for Rockport Plant, Unit 1 from 2044 to 2028 combined with increased investment at the Cook Plant related to the Life Cycle Management Project. Additionally, the total proposed increase includes incremental costs related to the Cook Plant Life Cycle Management Program and increased vegetation management expenses. In October 2017, the MPSC staff and intervenors filed testimony. The MPSC staff recommended an annual net revenue increase of $49 million including proposed retirement dates of 2028 for both Rockport Plant, Units 1 (from 2044) and 2 (from 2022) and a return on common equity of 9.8%. The intervenors proposed certain adjustments to I&M's request including no change to the current 2044 retirement date of Rockport Plant, Unit 1, but did not propose an annual net revenue increase. Their recommended return on common equity ranged from 9.3% to 9.5%. A hearing at the MPSC is scheduled for November 2017. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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. As of September 30, 2017, total costs incurred related to this project, including AFUDC, were approximately $17 million. The filing included a request for authorization for I&M to defer its Indiana jurisdictional ownership share of costs including investment carrying costs at a weighted average cost of capital (WACC), depreciation over a 10-year period as provided by statute and other related expenses. I&M proposed recovery of these costs using the existing Clean Coal Technology Rider in a future filing subsequent to approval of the SCR project. The AEGCo ownership share of the proposed SCR project will be billable under the Rockport Unit Power Agreement to I&M and KPCo and will be subject to future regulatory approval for recovery. In February 2017, the Indiana Office of Utility Consumer Counselor (OUCC) and other parties filed testimony with the IURC. The OUCC recommended approval of the CPCN but also stated that any decision regarding recovery of any under-depreciated plant due to retirement should be fully investigated in a base rate case, not in a tracker or other abbreviated proceeding. The other parties recommended either denial of the CPCN or approval of the CPCN with conditions including a cap on the amount of SCR costs allowed to be recovered in the rider and limitations on other costs related to legal issues involving the Rockport Plant, Unit 2 lease. A hearing at the IURC was held in March 2017. An order from the IURC is pending. In July 2017, I&M filed a motion with the U.S. District Court for the Southern District of Ohio to remove the requirement to install SCR technology at Rockport Plant, Unit 2. In August 2017, the district court delayed the deadline for installation of the SCR technology until March 2020.

KPCo Rate Matters (Applies to AEP)

2017 Kentucky Base Rate Case

In June 2017, KPCo filed a request with the KPSC for a $66 million annual increase in Kentucky base rates based upon a proposed 10.31% return on common equity with the increase to be implemented no later than January 2018. The proposed increase includes: (a) lost load since KPCo last changed base rates in July 2015, (b) incremental costs related to OATT charges from PJM not currently recovered from retail ratepayers, (c) increased depreciation expense including updated Big Sandy Plant, Unit 1 depreciation rates using a proposed retirement date of 2031, (d) recovery of other Big Sandy Plant, Unit 1 generation costs currently recovered through a retail rider and (e) incremental purchased power costs. Additionally, KPCo requested a $4 million annual increase in environmental surcharge revenues.

In August 2017, KPCo submitted a supplemental filing with the KPSC that decreased the proposed annual base rate revenue request to $60 million. The modification was due to a lower interest expense related to June 2017 debt refinancings. In October 2017, various intervenors filed testimony that included annual net revenue increase recommendations ranging from $13 million to $40 million. Intervenors recommended returns on common equity ranging from 8.6% to 8.85%. Intervenors also recommended significant delays in KPCo's proposed recoveries of: (a) depreciation expense related to Big Sandy Plant, Unit 1 (gas unit), proposing a 30-year depreciable life instead of KPCo's proposed 15-year life and (b) lease expense on Rockport Plant, Unit 2 billed from AEGCo, proposing that the approximate $100 million of lease expense for the period 2018 through 2022 be deferred with a WACC carrying charge for recovery over 10 years beginning 2023. Testimony on behalf of the Attorney General also discussed that the KPSC could consider disallowing all or a portion of the costs currently being recovered over 25 years through the Big Sandy Plant, Unit 2 retirement rider. As of September 30, 2017, KPCo's regulatory asset related to the retired Big Sandy Plant, Unit 2 was $289 million. A hearing at the KPSC is scheduled for December 2017.

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

OPCo Rate Matters (Applies to AEP and OPCo)

Ohio Electric Security Plan Filings

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 DIR, effective June 2015 through May 2018. The proposal also involved a PPA rider that would include OPCo's OVEC contractual entitlement (OVEC PPA) and would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based PPA.

In 2015, the PUCO issued orders that approved OPCo's ESP application, subject to certain modifications, with a return on common equity of 10.2% on capital costs for certain riders. The orders 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 OVEC PPA and (c) the option for OPCo to reapply in a future proceeding with a more detailed PPA proposal. Also in 2015, OPCo subsequently filed an amended OVEC PPA application that, among other things, addressed certain PPA requirements set forth in a 2015 PUCO order. In 2016, the PUCO issued an additional order on rehearing that approved the DIR caps with additional amendments.

In 2016, the PUCO issued orders that approved a contested stipulation agreement related to the PPA rider application. Additionally, as part of these orders, the PUCO approved (a) recovery of OVEC-related net margin incurred beginning June 2016, (b) potential additional contingent customer credits of up to $15 million to be included in the PPA rider over the final four years of the PPA rider and (c) 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 MWs and a wind energy project(s) of at least 500 MWs, with 100% of all output to be received by OPCo. AEP affiliates could own up to 50% of these solar and wind projects. In December 2016, in accordance with the stipulation agreement, OPCo filed a carbon reduction plan that focused on fuel diversification and carbon emission reductions. In April 2017, the PUCO rejected all pending rehearing requests and the orders are all now final. In June 2017, intervenors filed appeals to the Supreme Court of Ohio stating that the PUCO's approval of the OVEC PPA was unlawful and does not provide customers with rate stability.

In November 2016, OPCo refiled its amended ESP extension application and supporting testimony, consistent with the terms of the modified and approved stipulation agreement and based upon a 2016 PUCO order. The amended filing proposed to extend the ESP through May 2024 and included (a) an extension of the OVEC PPA rider, (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 Renewable Resource Rider.

In August 2017, OPCo and various intervenors filed a stipulation agreement with the PUCO. The stipulation extends the term of the ESP through May 2024 and includes: (a) an extension of the OVEC PPA rider, (b) a proposed 10% 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) rate caps related to OPCo's DIR ranging from $215 million to $290 million for the periods 2018 through 2021 and (e) the addition of various new riders, including a Smart City Rider and a Renewable Generation Rider. DIR rate caps will be reset in OPCo's next distribution base rate case which must be filed by June 2020. In October 2017, intervenor testimony opposing the stipulation agreement was filed recommending: (a) a return on common equity to not exceed 9.3% for riders earning a return on capital investments, (b) that OPCo should file a base distribution case concurrent with the conclusion of the current ESP in May 2018 and (c) denial of certain new riders proposed in OPCo's ESP extension. The stipulation is subject to review by the PUCO. A hearing at the PUCO is scheduled for November 2017.

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.

2016 SEET Filing

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 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.

In December 2016, OPCo recorded a 2016 SEET provision of $58 million based upon projected earnings data for companies in the comparable utilities risk group. In determining OPCo's return on equity in relation to the comparable utilities risk group, management excluded the following items resolved in OPCo's Global Settlement: (a) gain on the deferral of RSR costs, (b) refunds to customers related to the SEET remands and (c) refunds to customers related to fuel adjustment clause proceedings. In May 2017, OPCo submitted its 2016 SEET filing with the PUCO in which management indicated that OPCo did not have significantly excessive earnings in 2016 based upon actual earnings data for the comparable utilities risk group. Although management believes that OPCo's adjusted 2016 earnings were not excessive, management did not adjust OPCo's 2016 SEET provision due to risks that the PUCO could rule against OPCo's SEET treatment of the Global Settlement issues described above or adopt a different 2016 SEET threshold. If the PUCO orders a refund of 2016 OPCo earnings, it could reduce future net income and cash flows and impact financial condition.

PSO Rate Matters (Applies to AEP and PSO)

2017 Oklahoma Base Rate Case

In June 2017, PSO filed an application for a base rate review with the OCC that requested a net increase in annual revenues of $156 million based upon a proposed 10% return on common equity. The proposed base rate increase includes (a) environmental compliance investments, including recovery of previously deferred environmental compliance related costs currently recorded as regulatory assets, (b) Advanced Metering Infrastructure investments, (c) additional capital investments and costs to serve PSO's customers, and (d) an annual $42 million depreciation rate increase due primarily to shorter service lives and lower net salvage estimates. As part of this filing, consistent with the OCC's final order in its previous base rate case, PSO requested recovery through 2040 of Northeastern Plant, Unit 3, including the environmental control investment, and the net book value of Northeastern Plant, Unit 4 that was retired in 2016. As of September 30, 2017, the net book value of Northeastern Plant, Unit 4 was $82 million.

In September 2017, various intervenors and the OCC staff filed testimony that included annual net revenue increase recommendations ranging from $28 million to $108 million. The recommended returns on common equity ranged from 8% to 9%. In addition, certain parties recommended investment disallowances that ranged from $27 million to $82 million related to Northeastern Plant, Unit 4 and $38 million associated with capitalized incentives. Also, a party recommended a potential refund of $43 million related to an SPP rider claiming that PSO did not adequately support the related SPP costs. The combined total impact could result in a write-off and refund of up to approximately $163 million. In addition, if similar plant recovery issues would apply to Northeastern Plant, Unit 3, the net book value of plant, including regulatory assets, materials and supplies inventory and CWIP of $346 million as of September 30, 2017, could be adversely impacted. A hearing at the OCC is scheduled to begin in October 2017.

If any of these costs 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 June 2017, the Texas District Court upheld the PUCT's 2014 order. In July 2017, intervenors filed appeals with the Texas Third Court of Appeals.

If certain parts of the PUCT order are overturned and 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.

2016 Texas Base Rate Case

In December 2016, SWEPCo filed a request with the PUCT for a net increase in Texas annual revenues of $69 million based upon a 10% return on common equity. The annual increase includes approximately: (a) $34 million related to additional environmental controls, including those installed at the Welsh Plant, to comply with Federal EPA mandates, (b) $25 million for additional generation, transmission and distribution investments and increased operating costs, (c) $8 million related to transmission cost recovery within SWEPCo's regional transmission organization and (d) $2 million in additional vegetation management. As part of this filing, SWEPCo requested recovery of the Texas jurisdictional share (approximately 33%) of the net book value of Welsh Plant, Unit 2 through 2042, the remaining life of Welsh Plant, Unit 3.

In April and May 2017, various intervenors and the PUCT staff filed testimony that included annual net revenue increase recommendations ranging from $36 million to $47 million. The recommended returns on common equity ranged from 9.2% to 9.35%. In addition, no parties recommended approval of SWEPCo's proposed transmission cost recovery and certain parties recommended investment disallowances that could result in write-offs of up to approximately $89 million, including approximately $40 million related to environmental investments and $25 million related to Welsh Plant, Unit 2. A hearing at the PUCT was held in June 2017.

In September 2017, the Administrative Law Judges (ALJs) issued their proposal for decision including an annual net revenue increase of $50 million including recovery of Welsh Plant, Unit 2 environmental investments as of June 30,

2016. The ALJs proposed a return on common equity of 9.6% and recovery of but no return on Welsh Plant, Unit 2. The ALJs rejected SWEPCo’s proposed transmission cost recovery mechanism. The estimated potential write-off associated with the ALJs proposal is approximately $22 million which includes $9 million associated with the lack of a return on Welsh Plant, Unit 2.

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

Louisiana Turk Plant Prudence Review

Beginning January 2013, SWEPCo's formula rates, including the Louisiana jurisdictional share (approximately 33%) of the Turk Plant, have been collected subject to refund pending the outcome of a prudence review of the Turk Plant investment, which was placed into service in December 2012. In October 2017, the LPSC staff filed testimony contending that SWEPCo failed to continue to evaluate the suspension or cancellation of the Turk Plant during its construction period. The testimony also identified five individual items totaling approximately $51 million for potential disallowance relating to Louisiana's jurisdictional share of Turk Plant. As a result of SWEPCo's alleged failure to meet its continuing prudence obligations, the LPSC staff recommends one of the following potential unfavorable scenarios: (a) Even sharing of construction cost overruns between SWEPCo and ratepayers, (b) an imposition of a cost cap similar to Texas or (c) approximately a 1% reduction of the rate on common equity for the Turk Plant. As SWEPCo has included the full value of the Turk Plant in rate base since its in-service date, SWEPCo may be required to refund potential over-collections from January 2013 through the date new rates are implemented. As of September 30, 2017, if the LPSC adopts one of these potential scenarios, and disallows the five individual items, pretax write-offs could range from $50 million to $80 million and refund provisions, including interest, could range from $15 million to $27 million. Future annual revenue reductions could range from $3 million to $4 million. Management will continue to vigorously defend against these claims. If the LPSC orders in favor of one of these scenarios, it could reduce future net income and cash flows and impact financial condition. A hearing at the LPSC is scheduled for December 2017.

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.

2017 Louisiana Formula Rate Filing

In April 2017, the LPSC approved an uncontested stipulation agreement that SWEPCo filed for its formula rate plan for test year 2015. The filing included a net annual increase not to exceed $31 million, which was effective May 2017 and includes SWEPCo's Louisiana jurisdictional share of Welsh Plant and Flint Creek Plant environmental controls which were placed in service in 2016. These environmental costs are subject to prudence review. The net annual increase is subject to refund. In October 2017, SWEPCo filed testimony in Louisiana supporting the prudence of its environmental control investment for Welsh Plant, Units 1 and 3 and Flint Creek power plants. A hearing at the LPSC is scheduled for May 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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 total approximately $850 million, excluding AFUDC. As of September 30, 2017, SWEPCo had incurred costs of $398 million, including AFUDC, related to these projects. Management continues to evaluate the impact of environmental rules and related project cost estimates. As of September 30, 2017, the total net book value of Welsh Plant, Units 1 and 3 was $626 million, before cost of removal, including materials and supplies inventory and CWIP.

In 2016, as approved by the APSC, SWEPCo began recovering $79 million related to the Arkansas jurisdictional share of these environmental costs, subject to prudence review in the next Arkansas filed base rate proceeding. In

December 2016, the LPSC approved deferral of certain expenses related to the Louisiana jurisdictional share of environmental controls installed at Welsh Plant. In April 2017, the LPSC approved SWEPCo’s recovery of these deferred costs effective May 2017. SWEPCo’s approved Louisiana jurisdictional share of Welsh Plant deferrals: (a) are $11 million, excluding $6 million of unrecognized equity as of September 30, 2017, (b) is subject to review by the LPSC, and (c) includes a WACC return on environmental investments and the related depreciation expense and taxes. Effective May

2017, SWEPCo began recovering $131 million in investments related to its Louisiana jurisdictional share of environmental costs. SWEPCo has sought recovery of its project costs from retail customers in its current Texas base rate case at the PUCT and is recovering these costs from wholesale customers through SWEPCo's FERC-approved agreements. See "2016 Texas Base Rate Case" and "2017 Louisiana Formula Rate Filing" disclosures above.

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

FERC Rate Matters

PJM Transmission Rates (Applies to AEP, AEPTCo, APCo, I&M and OPCo)

In June 2016, PJM transmission owners, including AEP's eastern transmission subsidiaries and various state commissions filed a settlement agreement at 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 - AEP's PJM Participants (Applies to AEP, AEPTCo, APCo, I&M and OPCo)

In October 2016, several parties filed a joint complaint at the FERC that states the base return on common equity used by AEP's eastern transmission subsidiaries in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. Management believes its financial statements adequately address the impact of the complaint. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

Modifications to AEP's PJM Transmission Rates (Applies to AEP, AEPTCo, APCo, I&M and OPCo)

In November 2016, AEP's eastern transmission subsidiaries filed an application with at the FERC to modify the PJM OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to projected expenses. In March 2017, the FERC accepted the proposed modifications effective January 1, 2017, subject to refund, and set this matter for hearing and settlement procedures. Effective January 1, 2017, the modified PJM OATT formula rates were implemented, subject to refund, based on projected 2017 calendar year financial activity and projected plant balances. If the FERC determines that any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

FERC Transmission Complaint - AEP's SPP Participants (Applies to AEP, AEPTCo, PSO and SWEPCo)

In June 2017, several parties filed a joint complaint at the FERC that states the base return on common equity used by AEP's western transmission subsidiaries in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.36%, effective upon the date of the complaint. Management believes its financial statements adequately address the impact of the complaint. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

FERC SWEPCo Power Supply Agreements Complaint - East Texas Electric Cooperative, Inc. (ETEC) and Northeast Texas Electric Cooperative, Inc. (NTEC)

In September 2017, ETEC and NTEC filed a complaint at the FERC that states the base return on common equity used by SWEPCo in calculating their power supply formula rates is excessive and should be reduced from 11.1% to 8.41%, effective upon the date of the complaint. Management believes its financial statements adequately address the impact of the complaint. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

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 AEP's and AEPTCo's 2016 Annual Reports should be read in conjunction with this report.

GUARANTEES

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

Letters of Credit (Applies to AEP 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 a $3 billion revolving credit facility due in June 2021, under which up to $1.2 billion may be issued as letters of credit on behalf of subsidiaries. As of September 30, 2017, no letters of credit were issued under the $3 billion revolving credit facility. In May 2017, the $500 million revolving credit facility due in June 2018 was terminated.

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 five uncommitted facilities totaling $445 million. In August 2017, AEP executed a $75 million uncommitted letter of credit facility due in August 2018. As of September 30, 2017, the Registrants' maximum future payments for letters of credit issued under the uncommitted facilities were as follows:

Company	Amount (in millions)	Maturity
AEP	$ 123.2	October 2017 to September 2018
OPCo	0.6	September 2018

AEP has $45 million of variable rate Pollution Control Bonds supported by $46 million of bilateral letters of credit maturing in July 2019.

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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, which increased to $140 million in October 2017. 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. It is estimated the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of $76 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of September 30, 2017, SWEPCo has collected $71 million through a rider for final mine closure and reclamation costs, of which $76 million is recorded in Asset Retirement Obligations, offset by $5 million that is recorded in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheet.

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

Guarantees of Equity Method Investees (Applies to AEP)

AEP issued a performance guarantee for a 50% owned joint venture which is accounted for as an equity method investment. If the joint venture were to default on payments or performance, AEP would be required to make payments on behalf of the joint venture. As of September 30, 2017, the maximum potential amount of future payments associated with this guarantee was $75 million, which expires in December 2019.

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, 2017, 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, 2017, 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	$ 42.1
APCo	8.8
I&M	3.4
OPCo	6.0
PSO	3.3
SWEPCo	3.7

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 $8 million and $9 million for I&M and SWEPCo, respectively, for the remaining railcars as of September 30, 2017.

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 $8 million and $10 million for I&M and SWEPCo, respectively, as of September 30, 2017, 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. 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, 2017, the maximum potential amount of future payments required under the guaranteed leases was $52 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 to the extent of the sale proceeds. As of September 30, 2017, AEP's boat and barge lease guarantee liability was $7 million, of which $1 million was recorded in Other Current Liabilities and $6 million was recorded in Deferred Credits and Other Noncurrent Liabilities on AEP's balance sheet.

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, 2017, I&M's accrual for all of these sites is $3 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 2,278 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.

Westinghouse Electric Company Bankruptcy Filing (Applies to AEP and I&M)

In March 2017, Westinghouse filed a petition to reorganize under Chapter 11 of the U.S. Bankruptcy Code. It intends to reorganize, not cease business operations. However, it is in the early stages of the bankruptcy process and it is unclear whether the company can successfully reorganize. Westinghouse and I&M have a number of significant ongoing contracts relating to reactor services, nuclear fuel fabrication, and ongoing engineering projects. The most significant of these relate to Cook Plant fuel fabrication. I&M is evaluating how this reorganization affects these contracts. Westinghouse has stated that it intends to continue performance on I&M’s contracts, but given the importance of upcoming dates in the fuel fabrication process for Cook Plant, and their vital part in Cook Plant’s ongoing operations, I&M continues to work with Westinghouse in the bankruptcy proceedings to avoid any interruptions to that service. In the unlikely event Westinghouse rejects I&M’s contracts, or is unable to reorganize or sell its profitable businesses in the bankruptcy, Cook Plant’s operations would be significantly impacted and potentially shut down temporarily as I&M seeks other vendors for these services.

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 plaintiffs further allege that the defendants’ actions constitute breach of the lease and participation agreement. The plaintiffs seek a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M.

In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiffs’ claims, including the dismissal without prejudice of plaintiffs’ claims seeking compensatory damages. 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 plaintiffs 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 plaintiffs’ motion for partial judgment and filed a motion to dismiss the case for failure to state a claim.

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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 an appeal in the U.S. Court of Appeals for the Sixth Circuit 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.

In April 2017, the U.S. Court of Appeals for the Sixth Circuit issued an opinion reversing the district court's decisions which had dismissed certain of plaintiffs' claims for breach of contract and remanding the case to the district court to enter summary judgment in plaintiffs' favor consistent with that ruling. In April 2017, AEGCo and I&M filed a petition for rehearing with the U.S. Court of Appeals for the Sixth Circuit, which was granted. In June 2017, the U.S. Court of Appeals for the Sixth Circuit issued an amended opinion and judgment which reverses the district court's dismissal of certain of the owners' claims under the lease agreements, vacates the denial of the owners' motion for partial summary judgment and remands the case to the district court for further proceedings. The amended opinion and judgment also affirms the district court's dismissal of the owners' breach of good faith and fair dealing claim as duplicative of the breach of contract claims and removes the instruction to the district court in the original opinion to enter summary judgment in favor of the owners.

In July 2017, AEP filed a motion with the U.S. District Court for the Southern District of Ohio seeking to modify the consent decree to eliminate the obligation to install future controls at Rockport Plant, Unit 2 if AEP does not acquire ownership of that Unit, and to modify the consent decree in other respects to preserve the environmental benefits of the consent decree. In October 2017, the owners filed a motion to stay their claims until January 2018, to afford time for resolution of AEP's motion to modify the consent decree.

Management will continue to defend against the claims. Given that the district court dismissed plaintiffs' claims seeking compensatory relief as premature, and that plaintiffs have yet to present a methodology for determining or any analysis supporting any alleged damages, 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, a lawsuit was commenced 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 state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP 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 United States Supreme Court affirmed the U.S. Court of Appeals for the Ninth Circuit's opinion. The cases were remanded to the district court for further proceedings. AEP had four pending cases, of which three were class actions and one was a single plaintiff case. In February 2017, a settlement was reached in the single plaintiff case. A settlement was also reached in the three class actions and the district court issued final approval of the settlement in June 2017.

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. Twelve of the family members are pursuing personal injury/illness claims (non-working direct 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, defendants filed a motion to dismiss the complaint, contending the case should be filed in Ohio. In August 2015, the court denied the motion. Defendants 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 (WVMLP), rather than back to the Mason County, West Virginia Circuit Court. Defendants subsequently filed a motion to dismiss the twelve non-working direct claims under Ohio law. The WVMLP denied the motion and defendants again appealed to the West Virginia Supreme Court. The West Virginia Supreme Court granted the appeal of the twelve non-working direct claims and heard oral argument in March 2017. In June 2017, the West Virginia Supreme Court reversed the WVMLP decision and dismissed the claims of the twelve non-working direct claim plaintiffs. Management will continue to defend against the remaining claims and believes the provision recorded is adequate. Management is unable to determine a range of potential additional losses that are reasonably possible of occurring.

6. IMPAIRMENT, DISPOSITION, AND ASSETS AND LIABILITIES HELD FOR SALE

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

IMPAIRMENT

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. 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.

Through the third quarter of 2017, AEP recorded an additional pretax impairment of $4 million in Asset Impairments and Other Related Charges on AEP's statements of income related to the Merchant Coal-fired Generation Assets. In addition, AEP recorded a $7 million pretax impairment as Asset Impairments and Other Related Charges on AEP's statements of income related to the sale of Zimmer Plant. The sale is further discussed in the "Disposition" section of this note.

DISPOSITION

Zimmer Plant (Generation & Marketing Segment)

In February 2017, AEP signed an agreement to sell its 25.4% ownership share of Zimmer Plant to a nonaffiliated party. The transaction closed in the second quarter of 2017 and did not have a material impact on net income, cash flows or financial condition. The Income before Income Tax Expense and Equity Earnings of Zimmer Plant was immaterial for the three and nine months ended September 30, 2017 and 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 did not 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.

Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)

In September 2016, AEP signed a Purchase and Sale Agreement to sell AGR's Gavin, Waterford and Darby Plants as well as AEGCo's Lawrenceburg Plant totaling 5,329 MWs of competitive generation assets to a nonaffiliated party. The sale closed in January 2017 for $2.2 billion, which was recorded in Investing Activities on the statement of cash flows. The net proceeds from the transaction were $1.2 billion in cash after taxes, repayment of debt associated with these assets including a make whole payment related to the debt, payment of a coal contract associated with one of the plants and transaction fees. The sale resulted in a pretax gain of $226 million that was recorded in Gain on Sale of Merchant Generation Assets on AEP's statement of income.

ASSETS AND LIABILITIES HELD FOR SALE

Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)

In the third quarter of 2016, management determined Gavin, Waterford, Darby and Lawrenceburg Plants met the classification of held for sale. 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 December 31, 2016 and as shown in the table below. The Income before Income Tax Expense and Equity Earnings of the four plants was approximately $116 million for the three months ended September 30, 2016 and $42 million (excluding the $226 million pretax gain) and $312 million for the nine months ended September 30, 2017 and 2016, respectively.

	December 31, 2016
Assets:	
Fuel	$ 145.5
Materials and Supplies	49.4
Property, Plant and Equipment - Net	1,756.2
Other Class of Assets That Are Not Major	0.1
Total Assets Classified as Held for Sale on the Balance Sheets	$ 1,951.2
Liabilities:	
Long-term Debt	$ 134.8
Waterford Plant Upgrade Liability	52.2
Asset Retirement Obligations	36.7
Other Classes of Liabilities That Are Not Major	12.2
Total Liabilities Classified as Held for Sale on the Balance Sheets	$ 235.9

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7. BENEFIT PLANS

The disclosures in this note apply to all Registrants except AEPTCo 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:

AEP

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$24.1	$21.4	$2.8	$2.6
Interest Cost	50.7	52.9	14.8	15.3
Expected Return on Plan Assets	(71.1)	(70.1)	(25.3)	(26.8)
Amortization of Prior Service Cost (Credit)	0.3	0.6	(17.3)	(17.3)
Amortization of Net Actuarial Loss	20.7	21.0	9.2	7.8
Net Periodic Benefit Cost (Credit)	$24.7	$25.8	$(15.8)	$(18.4)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$72.3	$64.3	$8.4	$7.7
Interest Cost	152.3	158.7	44.5	45.7
Expected Return on Plan Assets	(213.5)	(210.2)	(76.0)	(80.3)
Amortization of Prior Service Cost (Credit)	0.8	1.7	(51.8)	(51.8)
Amortization of Net Actuarial Loss	62.1	62.9	27.5	23.5
Net Periodic Benefit Cost (Credit)	$74.0	$77.4	$(47.4)	$(55.2)

APCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$2.3	$2.1	$0.3	$0.2
Interest Cost	6.5	6.8	2.6	2.7
Expected Return on Plan Assets	(8.9)	(8.8)	(4.1)	(4.3)
Amortization of Prior Service Credit	—	—	(2.5)	(2.5)
Amortization of Net Actuarial Loss	2.6	2.6	1.6	1.4
Net Periodic Benefit Cost (Credit)	$2.5	$2.7	$(2.1)	$(2.5)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$7.0	$6.1	$0.8	$0.7
Interest Cost	19.3	20.4	7.9	8.1
Expected Return on Plan Assets	(26.8)	(26.5)	(12.3)	(13.0)
Amortization of Prior Service Cost (Credit)	0.1	0.1	(7.5)	(7.5)
Amortization of Net Actuarial Loss	7.8	8.0	4.7	4.1
Net Periodic Benefit Cost (Credit)	$7.4	$8.1	$(6.4)	$(7.6)

I&M

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$3.5	$3.1	$0.4	$0.4
Interest Cost	6.1	6.3	1.7	1.7
Expected Return on Plan Assets	(8.6)	(8.4)	(3.1)	(3.2)
Amortization of Prior Service Credit	—	—	(2.3)	(2.4)

Amortization of Net Actuarial Loss	2.4	2.5	1.1	0.9
Net Periodic Benefit Cost (Credit)	$3.4	$3.5	$(2.2)	$(2.6)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$10.5	$9.2	$1.2	$1.1
Interest Cost	18.2	19.0	5.2	5.2
Expected Return on Plan Assets	(25.9)	(25.2)	(9.2)	(9.6)
Amortization of Prior Service Cost (Credit)	0.1	0.1	(7.0)	(7.1)
Amortization of Net Actuarial Loss	7.3	7.4	3.3	2.8
Net Periodic Benefit Cost (Credit)	$10.2	$10.5	$(6.5)	$(7.6)

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OPCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$1.8	$1.6	$0.3	$0.2
Interest Cost	4.8	5.1	1.6	1.8
Expected Return on Plan Assets	(6.9)	(6.9)	(3.0)	(3.3)
Amortization of Prior Service Credit	—	—	(1.7)	(1.7)
Amortization of Net Actuarial Loss	2.0	2.1	1.1	0.9
Net Periodic Benefit Cost (Credit)	$1.7	$1.9	$(1.7)	$(2.1)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$5.6	$4.9	$0.7	$0.6
Interest Cost	14.5	15.4	5.0	5.3
Expected Return on Plan Assets	(20.9)	(20.8)	(9.0)	(9.7)
Amortization of Prior Service Cost (Credit)	0.1	0.1	(5.2)	(5.2)
Amortization of Net Actuarial Loss	5.9	6.1	3.3	2.8
Net Periodic Benefit Cost (Credit)	$5.2	$5.7	$(5.2)	$(6.2)

PSO

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$1.7	$1.5	$0.2	$0.2
Interest Cost	2.6	2.8	0.8	0.8
Expected Return on Plan Assets	(3.9)	(3.9)	(1.4)	(1.5)
Amortization of Prior Service Cost (Credit)	—	0.1	(1.1)	(1.1)

Amortization of Net Actuarial Loss	1.1	1.1	0.5	0.4
Net Periodic Benefit Cost (Credit)	$1.5	$1.6	$(1.0)	$(1.2)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$4.9	$4.6	$0.5	$0.5
Interest Cost	8.0	8.4	2.4	2.4
Expected Return on Plan Assets	(11.8)	(11.6)	(4.2)	(4.5)
Amortization of Prior Service Cost (Credit)	—	0.2	(3.2)	(3.2)
Amortization of Net Actuarial Loss	3.3	3.3	1.5	1.3
Net Periodic Benefit Cost (Credit)	$4.4	$4.9	$(3.0)	$(3.5)

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SWEPCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$2.1	$2.0	$0.2	$0.2
Interest Cost	3.1	3.1	0.9	0.9
Expected Return on Plan Assets	(4.2)	(4.0)	(1.5)	(1.7)
Amortization of Prior Service Credit	—	—	(1.3)	(1.3)
Amortization of Net Actuarial Loss	1.3	1.2	0.5	0.5
Net Periodic Benefit Cost (Credit)	$2.3	$2.3	$(1.2)	$(1.4)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$6.5	$6.1	$0.6	$0.6
Interest Cost	9.2	9.3	2.7	2.7
Expected Return on Plan Assets	(12.6)	(12.3)	(4.7)	(5.0)
Amortization of Prior Service Cost (Credit)	—	0.2	(3.9)	(3.9)
Amortization of Net Actuarial Loss	3.7	3.6	1.7	1.5
Net Periodic Benefit Cost (Credit)	$6.8	$6.9	$(3.6)	$(4.1)

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 and AEP Texas.
- OPCo purchases energy and capacity to serve SSO customers and provides transmission and distribution services for all connected load.
- With the merger of TCC and TNC into AEP Utilities, Inc. to form AEP Texas, the Transmission and Distribution segment now includes certain activities related to the former AEP Utilities, Inc. that had been included in Corporate and Other.

AEP Transmission Holdco

- Development, construction and operation of transmission facilities through investments in AEPTCo. These investments have FERC-approved returns on equity.
- Development, construction and operation of transmission facilities through investments in AEP's 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.
- Contracted renewable energy investments and management services.

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.

The tables below present AEP’s reportable segment income statement information for the three and nine months ended September 30, 2017 and 2016 and reportable segment balance sheet information as of September 30, 2017 and December 31, 2016. These amounts include certain estimates and allocations where necessary.

	Three Months Ended September 30, 2017						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Revenues from:							
External Customers	$2,453.8	$ 1,149.7	$ 45.1	$441.5	$ 14.6	$ —	$ 4,104.7
Other Operating Segments	28.4	23.6	133.4	24.0	16.7	(226.1)	—
Total Revenues	$2,482.2	$ 1,173.3	$ 178.5	$465.5	$ 31.3	$ (226.1)	$ 4,104.7
Income (Loss) from Continuing Operations	$297.3	$ 144.0	$ 76.5	$33.7	$ 5.2	$ —	$ 556.7
Loss from Discontinued Operations, Net of Tax	—	—	—	—	—	—	—
Net Income (Loss)	$297.3	$ 144.0	$ 76.5	$33.7	$ 5.2	$ —	$ 556.7

	Three Months Ended September 30, 2016						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
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	$ 155.7	$ 69.5	$(1,369.2)	$ 36.4	$ —	$ (764.2)
Loss from Discontinued Operations, Net of Tax	—	—	—	—	—	—	—
Net Income (Loss)	$343.4	$ 155.7	$ 69.5	$(1,369.2)	$ 36.4	$ —	$ (764.2)

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	Nine Months Ended September 30, 2017						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Revenues from:							
External Customers	$6,819.3	$ 3,242.7	$ 125.8	$1,386.8	$ 39.9	$ —	$ 11,614.5
Other Operating Segments	73.8	70.5	456.1	80.7	46.8	(727.9)	—
Total Revenues	$6,893.1	$ 3,313.2	$ 581.9	$1,467.5	$ 86.7	$ (727.9)	$ 11,614.5
Income (Loss) from Continuing Operations	$639.2	$ 374.3	$ 278.3	$246.3	$ (11.0)	$ —	$ 1,527.1
Loss from Discontinued Operations, Net of Tax	—	—	—	—	—	—	—
Net Income (Loss)	$639.2	$ 374.3	$ 278.3	$246.3	$ (11.0)	$ —	$ 1,527.1

	Nine Months Ended September 30, 2016						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
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	$ 387.8	$ 209.5	$(1,248.8)	$ 64.2	$ —	$ 245.3
Loss from Discontinued Operations, Net of Tax	—	—	—	—	(2.5)	—	(2.5)
Net Income (Loss)	$832.6	$ 387.8	$ 209.5	$(1,248.8)	$ 61.7	$ —	$ 242.8

	September 30, 2017						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Property, Plant and Equipment	$42,722.9	$15,695.2	$6,394.2	$632.9	$359.5	$(366.5) (b)	$65,438.2
Accumulated Depreciation and Amortization	13,042.9	3,766.2	156.6	161.7	180.8	(186.5) (b)	17,121.7
Total Property Plant and Equipment - Net	$29,680.0	$11,929.0	$6,237.6	$471.2	$178.7	$(180.0) (b)	$48,316.5
Total Assets	$38,136.4	$15,765.0	$7,631.2	$1,904.4	$22,339.9	$(21,812.0) (b) (c)	$63,964.9
Long-term Debt Due Within One Year:							
Non-Affiliated	$1,107.2	$703.4	$—	$0.1	$548.6	$—	$2,359.3
Long-term Debt:							
Affiliated	50.0	—	—	32.2	—	(82.2)	—
Non-Affiliated	10,644.2	4,738.0	2,682.1	(0.3)	298.4	—	18,362.4
Total Long-term Debt	$11,801.4	$5,441.4	$2,682.1	$32.0	$847.0	$(82.2)	$20,721.7

	December 31, 2016						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Property, Plant and Equipment	$41,552.6	$14,762.2	$5,354.0	$364.7	$356.6	$(353.5) (b)	$62,036.6
Accumulated Depreciation and Amortization	12,596.7	3,655.0	101.4	42.2	186.0	(184.0) (b)	16,397.3
Total Property Plant and Equipment - Net	$28,955.9	$11,107.2	$5,252.6	$322.5	$170.6	$(169.5) (b)	$45,639.3
Assets Held for Sale	$—	$—	$—	$1,951.2	$—	$—	$1,951.2
Total Assets	$37,428.3	$14,802.4	$6,384.8	$3,386.1	$20,354.8	$(18,888.7) (b) (c)	$63,467.7
Long-term Debt Due Within One Year:							
Non-Affiliated	$1,519.9	$309.4	$—	$500.1	$548.6	$—	$2,878.0
Long-term Debt:							

Affiliated	20.0	—	—	32.2	—	(52.2)	—
Non-Affiliated	10,353.3	4,672.2	2,055.7	—	297.2	—	17,378.4
Total Long-term Debt	$ 11,893.2	$ 4,981.6	$ 2,055.7	$ 532.3	$ 845.8	$ (52.2)	$ 20,256.4
Liabilities Held for Sale	$ —	$ —	$ —	$ 235.9	$ —	$ —	$ 235.9

(a) 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.

(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 (Applies to APCo, I&M, OPCo, PSO and SWEPCo)

The Registrant Subsidiaries, besides AEPTCo, each have one reportable segment, an integrated electricity generation, transmission and distribution business for APCo, I&M, PSO and SWEPCo, and an electricity transmission and distribution business for OPCo. Other activities are insignificant. 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.

AEPTCo's Reportable Segments

AEPTCo Parent is the holding company of seven FERC-regulated transmission-only electric utilities (State Transcos). The seven State Transcos have been identified as operating segments of AEPTCo under the accounting guidance for "Segment Reporting." The State Transcos business consists of developing, constructing and operating transmission facilities at the request of the RTO's in which they operate and in replacing and upgrading facilities, assets and components of the existing AEP transmission system as needed to maintain reliability standards and provide service to AEP's wholesale and retail customers. The State Transcos are regulated for rate-making purposes exclusively by FERC and earn revenues through tariff rates charged for the use of their electric transmission systems.

AEPTCo's Chief Operating Decision Maker makes operating decisions, allocates resources to and assesses performance based on these operating segments. The seven State Transco operating segments all have similar economic characteristics and meet all of the criteria under the accounting guidance for "Segment Reporting" to be aggregated into one operating segment. As a result, AEPTCo has one reportable segment. The remainder of AEPTCo's activity is presented in AEPTCo Parent. While not considered a reportable segment, AEPTCo Parent represents the activity of the holding company which primarily relates to debt financing activity and general corporate activities.

The tables below present AEPTCo's reportable segment income statement information for the three and nine months ended September 30, 2017 and 2016 and reportable segment balance sheet information as of September 30, 2017 and December 31, 2016. These amounts include certain estimates and allocations where necessary.

	Three Months Ended September 30, 2017			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$35.9	$ —	$ —	$ 35.9
Sales to AEP Affiliates	131.3	—	0.1	131.4
Total Revenues	$167.2	$ —	$ 0.1	$ 167.3
Interest Income	$—	$ 19.5	$ (19.3) (a)	$ 0.2
Interest Expense	16.9	19.3	(19.3) (a)	16.9
Income Tax Expense	30.2	—	—	30.2
Equity Earnings in State Transcos	—	59.8	(59.8) (b)	—
Net Income	$59.8	$ 59.9	$ (59.8) (b)	$ 59.9

	Three Months Ended September 30, 2016			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$33.5	$ —	$ —	$ 33.5

Sales to AEP Affiliates	91.8	—	—		91.8
Total Revenues	$125.3	$ —	$ —		$ 125.3
Interest Income	$—	$ 14.0	$ (13.9	) (a)	$ 0.1
Interest Expense	11.0	13.9	(13.9	) (a)	11.0
Income Tax Expense	26.4	—	—		26.4
Equity Earnings in State Transcos	—	52.3	(52.3	) (b)	—
Net Income	$52.3	$ 52.4	$ (52.3	) (b)	$ 52.4

	Nine Months Ended September 30, 2017			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$99.2	$ —	$ —	$ 99.2
Sales to AEP Affiliates	450.2	—	—	450.2
Total Revenues	$549.4	$ —	$ —	$ 549.4
Interest Income	$0.1	$ 58.0	$ (57.6) (a)	$ 0.5
Interest Expense	48.6	57.6	(57.6) (a)	48.6
Income Tax Expense	114.3	0.2	—	114.5
Equity Earnings in State Transcos	—	224.0	(224.0) (b)	—
Net Income	$224.0	$ 224.3	$ (224.0) (b)	$ 224.3

	Nine Months Ended September 30, 2016			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$89.6	$ —	$ —	$ 89.6
Sales to AEP Affiliates	268.4	—	—	268.4
Total Revenues	$358.0	$ —	$ —	$ 358.0
Interest Income	$—	$ 41.8	$ (41.6) (a)	$ 0.2
Interest Expense	32.3	41.6	(41.6) (a)	32.3
Income Tax Expense	73.9	—	—	73.9
Equity Earnings in State Transcos	—	153.0	(153.0) (b)	—
Net Income	$153.0	$ 153.0	$ (153.0) (b)	$ 153.0

	September 30, 2017			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Total Transmission Property	$6,067.5	$—	$ —	$ 6,067.5
Accumulated Depreciation and Amortization	151.5	—	—	151.5
Total Transmission Property – Net	$5,916.0	$—	$ —	$ 5,916.0
Notes Receivable - Affiliated	$—	$2,500.0	$ (2,500.0) (c)	$ —
Total Assets	$6,455.2	$5,010.8	$ (4,917.1) (d)	$ 6,548.9
Total Long-term Debt	$2,475.6	$2,574.4	$ (2,500.0) (c)	$ 2,550.0

	December 31, 2016			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Total Transmission Property	$5,054.2	$—	$ —	$ 5,054.2
Accumulated Depreciation and Amortization	99.6	—	—	99.6

Total Transmission Property – Net	$4,954.6	$—	$—		$ 4,954.6
Notes Receivable - Affiliated	$—	$1,950.0	$ (1,950.0	) (c)	$ —
Total Assets	$5,337.5	$3,947.8	$ (3,935.5	) (d)	$ 5,349.8
Total Long-term Debt	$1,932.0	$1,950.0	$ (1,950.0	) (c)	$ 1,932.0

(a) Elimination of intercompany interest income/interest expense on affiliated debt arrangement.
(b) Elimination of AEPTCo Parent’s equity earnings in the State Transcos.
(c) Elimination of intercompany debt.
(d) Primarily relates to the elimination of AEPTCo Parent’s investment in the State Transcos and Note Receivable from the State Transcos.

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9. DERIVATIVES AND HEDGING

The disclosures in this note apply to all Registrants unless indicated otherwise. For the periods presented, AEPTCo did not have any Derivative and Hedging activity.

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of AEP subsidiaries, including the Registrant Subsidiaries. AEP Energy Partners, LLC 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 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. For disclosure purposes, these risks are grouped as “Interest Rate.” 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:

Notional Volume of Derivative Instruments
September 30, 2017

Primary Risk Exposure	Unit of Measure	AEP	APCo	I&M	OPCo	PSO	SWEPCo
		(in millions)					
Commodity:							
Power	MWhs	406.0	73.7	45.8	10.6	13.7	34.5
Coal	Tons	0.5	—	0.2	—	—	0.3
Natural Gas	MMBtus	48.1	2.0	1.2	—	—	18.3
Heating Oil and Gasoline	Gallons	7.9	1.5	0.7	1.8	0.8	0.9
Interest Rate	USD	$53.2	$ —	$ —	$ —	$ —	$ —
Interest Rate	USD	$1,000.0	$ —	$ —	$ —	$ —	$ —

Notional Volume of Derivative Instruments
December 31, 2016

Primary Risk Exposure	Unit of Measure	AEP	APCo	I&M	OPCo	PSO	SWEPCo
		(in millions)					
Commodity:							
Power	MWhs	348.0	51.9	19.9	11.2	11.9	14.2
Coal	Tons	1.5	—	0.5	—	—	1.0
Natural Gas	MMBtus	32.8	—	—	—	—	—
Heating Oil and Gasoline	Gallons	7.4	1.4	0.7	1.6	0.8	0.9
Interest Rate	USD	$75.2	$ 0.1	$0.1	$ —	$ —	$ —
Interest Rate	USD	$500.0	$ —	$—	$ —	$ —	$ —

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. 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, 2017		December 31, 2016	
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	$3.5	$ 17.0	$ 7.9	$ 7.6
APCo	0.4	0.3	0.5	0.7
I&M	0.3	0.1	0.3	0.4
OPCo	0.1	—	0.2	—
PSO	—	—	0.1	—
SWEPCo	—	—	0.1	—

The following tables represent the gross fair value of the Registrants' derivative activity on the balance sheets:

AEP

Fair Value of Derivative Instruments
September 30, 2017

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (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	$277.4	$8.1	$4.2	$ 289.7	$(143.6)	$ 146.1
Long-term Risk Management Assets	348.1	3.8	—	351.9	(41.5)	310.4
Total Assets	625.5	11.9	4.2	641.6	(185.1)	456.5
Current Risk Management Liabilities	202.2	13.5	1.4	217.1	(147.7)	69.4
Long-term Risk Management Liabilities	329.6	74.0	—	403.6	(50.9)	352.7
Total Liabilities	531.8	87.5	1.4	620.7	(198.6)	422.1
Total MTM Derivative Contract Net Assets (Liabilities)	$93.7	$(75.6)	$2.8	$ 20.9	$13.5	$ 34.4

Fair Value of Derivative Instruments
December 31, 2016

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (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	$264.4	$13.2	$—	$ 277.6	$(183.1)	$ 94.5
Long-term Risk Management Assets	315.0	7.7	—	322.7	(33.6)	289.1
Total Assets	579.4	20.9	—	600.3	(216.7)	383.6
Current Risk Management Liabilities	227.2	6.3	—	233.5	(180.1)	53.4
Long-term Risk Management Liabilities	301.0	50.1	1.4	352.5	(36.3)	316.2
Total Liabilities	528.2	56.4	1.4	586.0	(216.4)	369.6

Total MTM Derivative Contract Net Assets (Liabilities)	$51.2	$(35.5)	$(1.4)	$ 14.3	$(0.3)	$ 14.0

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APCo
Fair Value of Derivative Instruments
September 30, 2017

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	$50.4	$ (20.1)	$ 30.3
Long-term Risk Management Assets	4.9	(4.3)	0.6
Total Assets	55.3	(24.4)	30.9
Current Risk Management Liabilities	20.7	(19.8)	0.9
Long-term Risk Management Liabilities	4.8	(4.5)	0.3
Total Liabilities	25.5	(24.3)	1.2
Total MTM Derivative Contract Net Assets (Liabilities)	$29.8	$ (0.1)	$ 29.7

Fair Value of Derivative Instruments
December 31, 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	$22.7	$ (20.1)	$ 2.6
Long-term Risk Management Assets	1.9	(1.9)	—
Total Assets	24.6	(22.0)	2.6
Current Risk Management Liabilities	20.6	(20.3)	0.3
Long-term Risk Management Liabilities	2.8	(1.9)	0.9
Total Liabilities	23.4	(22.2)	1.2
Total MTM Derivative Contract Net Assets	$1.2	$ 0.2	$ 1.4

I&M
Fair Value of Derivative Instruments
September 30, 2017

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	$27.4	$ (15.8)	$ 11.6
Long-term Risk Management Assets	3.3	(2.8)	0.5
Total Assets	30.7	(18.6)	12.1
Current Risk Management Liabilities	17.6	(15.6)	2.0
Long-term Risk Management Liabilities	3.0	(2.8)	0.2
Total Liabilities	20.6	(18.4)	2.2
Total MTM Derivative Contract Net Assets (Liabilities)	$10.1	$ (0.2)	$ 9.9

Fair Value of Derivative Instruments
December 31, 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	$14.9	$ (11.4)	$ 3.5
Long-term Risk Management Assets	1.1	(1.1)	—
Total Assets	16.0	(12.5)	3.5
Current Risk Management Liabilities	11.8	(11.5)	0.3
Long-term Risk Management Liabilities	1.9	(1.1)	0.8
Total Liabilities	13.7	(12.6)	1.1
Total MTM Derivative Contract Net Assets	$2.3	$ 0.1	$ 2.4

OPCo
Fair Value of Derivative Instruments
September 30, 2017

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	$0.3	$ (0.1)	$ 0.2
Long-term Risk Management Assets	—	—	—
Total Assets	0.3	(0.1)	0.2
Current Risk Management Liabilities	7.6	—	7.6
Long-term Risk Management Liabilities	130.9	—	130.9
Total Liabilities	138.5	—	138.5
Total MTM Derivative Contract Net Liabilities	$(138.2)	$ (0.1)	$ (138.3)

Fair Value of Derivative Instruments
December 31, 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	$0.4	$ (0.2)	$ 0.2
Long-term Risk Management Assets	—	—	—
Total Assets	0.4	(0.2)	0.2
Current Risk Management Liabilities	5.9	—	5.9
Long-term Risk Management Liabilities	113.1	—	113.1
Total Liabilities	119.0	—	119.0
Total MTM Derivative Contract Net Liabilities	$(118.6)	$ (0.2)	$ (118.8)

PSO
Fair Value of Derivative Instruments
September 30, 2017

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	$4.7	$ —	$ 4.7
Long-term Risk Management Assets	—	—	—
Total Assets	4.7	—	4.7
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets	$4.7	$ —	$ 4.7

Fair Value of Derivative Instruments
December 31, 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	$0.9	$ (0.1)	$ 0.8
Long-term Risk Management Assets	—	—	—
Total Assets	0.9	(0.1)	0.8
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets (Liabilities)	$0.9	$ (0.1)	$ 0.8

SWEPCo
Fair Value of Derivative Instruments
September 30, 2017

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	$ 12.7	$ (0.2)	$ 12.5
Long-term Risk Management Assets	0.7	—	0.7
Total Assets	13.4	(0.2)	13.2
Current Risk Management Liabilities	0.3	(0.2)	0.1
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.3	(0.2)	0.1
Total MTM Derivative Contract Net Assets	$ 13.1	$ —	$ 13.1

Fair Value of Derivative Instruments
December 31, 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	$ 1.1	$ (0.2)	$ 0.9
Long-term Risk Management Assets	—	—	—
Total Assets	1.1	(0.2)	0.9
Current Risk Management Liabilities	0.4	(0.1)	0.3
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.4	(0.1)	0.3
Total MTM Derivative Contract Net Assets (Liabilities)	$ 0.7	$ (0.1)	$ 0.6

(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.

The tables below present the Registrants' activity of derivative risk management contracts:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended September 30, 2017

Location of Gain (Loss)	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Vertically Integrated Utilities Revenues	$0.9	$ —	$—	$—	$—	$ —
Generation & Marketing Revenues	17.7	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	0.3	0.6	—	—	(0.1)
Purchased Electricity for Resale	1.0	0.3	0.2	—	—	—
Other Operation	0.1	—	—	0.1	—	—
Maintenance	0.1	0.1	—	0.1	—	—
Regulatory Assets (a)	(8.8)	0.1	(0.8)	(8.7)	—	0.3
Regulatory Liabilities (a)	15.6	3.7	2.1	—	2.6	7.0
Total Gain (Loss) on Risk Management Contracts	$26.6	$ 4.5	$2.1	$(8.5)	$2.6	$ 7.2

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 Utilities 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	(0.4)	—	—	(0.1)	—	—
Maintenance	(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 Nine Months Ended September 30, 2017

Location of Gain (Loss)	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Vertically Integrated Utilities Revenues	$7.0	$—	$—	$—	$—	$ —
Generation & Marketing Revenues	38.5	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	0.6	6.3	—	—	—
Purchased Electricity for Resale	4.9	1.6	0.5	—	—	—
Other Operation	0.5	—	—	0.1	—	—
Maintenance	0.4	0.1	—	0.1	—	—
Regulatory Assets (a)	(26.8)	—	(1.0)	(25.9)	—	0.1
Regulatory Liabilities (a)	81.8	28.2	15.3	—	13.7	22.0
Total Gain (Loss) on Risk Management Contracts	$106.3	$30.5	$21.1	$(25.7)	$13.7	$ 22.1

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 Utilities 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	(1.3)	(0.1)	(0.1)	(0.3)	(0.1)	(0.2)
Maintenance	(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

(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 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."

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 income. The following table shows the results of hedging gains (losses):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Gain (Loss) on Fair Value Hedging Instruments	$0.1	$(1.1)	$(0.1)	$3.0
Gain (Loss) on Fair Value Portion of Long-term Debt	(0.1)	1.1	0.1	(3.0)

During the three and nine months ended September 30, 2017 and 2016, 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, 2017 and 2016, AEP applied cash flow hedging to outstanding power derivatives. During the three and nine months ended September 30, 2017 and 2016, 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, 2017 and 2016, AEP applied cash flow hedging to outstanding interest rate derivatives. During the three and nine months ended September 30, 2017 and 2016, 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, 2017 and 2016, the Registrants did not apply cash flow hedging to any outstanding foreign currency derivatives.

During the three and nine months ended September 30, 2017 and 2016, 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 were:

Impact of Cash Flow Hedges on AEP's Balance Sheets

	September 30, 2017		December 31, 2016	
	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)			
Hedging Assets (a)	$4.3	$ 4.2	$ 11.2	$ —
Hedging Liabilities (a)	79.9	—	46.7	—
AOCI Gain (Loss) Net of Tax	(49.2)	(12.2)	(23.1)	(15.7)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(3.6)	(0.7)	4.3	(1.0)

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

As of September 30, 2017 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 123 months.

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

	September 30, 2017		December 31, 2016	
	Interest Rate			
Company	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months
	(in millions)			
APCo	$2.4	$ 0.7	$2.9	$ 0.7
I&M	(11.0)	(1.3)	(12.0)	(1.3)
OPCo	2.2	1.1	3.0	1.1
PSO	2.8	0.8	3.4	0.8
SWEPCo	(6.3)	(1.4)	(7.4)	(1.4)

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 mitigates 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. Some master agreements include margining, which requires a counterparty to post cash or letters of credit in the event exposure exceeds the established threshold. 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 default including a failure or inability to post collateral when required.

Collateral Triggering Events

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

A limited number of derivative contracts include collateral triggering events, which include a requirement to maintain certain credit ratings. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering events in contracts. AEP, APCo, I&M, PSO and SWEPCo have not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. The Registrants had immaterial derivative contracts with collateral triggering events in a net liability position as of September 30, 2017 and December 31, 2016.

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:

	September 30, 2017		
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	$285.9	$ 2.5	$ 274.4
APCo	—	—	—
I&M	—	—	—

	December 31, 2016		
	Liabilities for Contracts with Cross Default Provisions Prior to	Amount of Cash	Additional Settlement Liability if Cross Default Provision

Company	Contractual Netting Arrangements	Collateral Posted	is Triggered
	(in millions)		
AEP	$ 259.6	$ 0.4	$ 235.8
APCo	0.1	—	—
I&M	0.1	—	—

10. FAIR VALUE MEASUREMENTS

The disclosures in this note apply to all Registrants except AEPTCo 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.

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 (Applies to all Registrants)

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 are summarized in the following table:

Company	September 30, 2017 Book Value	September 30, 2017 Fair Value	December 31, 2016 Book Value	December 31, 2016 Fair Value
	(in millions)			
AEP	$20,721.7	$22,988.8	$20,391.2 (a)	$22,211.9 (a)
AEPTCo	2,550.0	2,720.8	1,932.0	1,984.3
APCo	3,979.3	4,721.3	4,033.9	4,613.2
I&M	2,658.5	2,898.7	2,471.4	2,661.6
OPCo	1,718.9	2,068.9	1,763.9	2,092.5
PSO	1,286.4	1,448.0	1,286.0	1,419.0
SWEPCo	2,441.5	2,620.7	2,679.1	2,814.3

(a) Amounts include debt related to the Lawrenceburg Plant that has been classified as Liabilities Held for Sale on the balance sheet and has a fair value of $172 million. See the Assets and Liabilities Held for Sale 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 AEP’s protected cell of EIS.

The following is a summary of Other Temporary Investments:

Other Temporary Investments	September 30, 2017 Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash (a)	$172.9	$ —	$ —	$172.9
Fixed Income Securities – Mutual Funds (b)	103.9	—	(0.7)	103.2
Equity Securities – Mutual Funds	16.8	17.8	—	34.6
Total Other Temporary Investments	$293.6	$ 17.8	$ (0.7)	$310.7

Other Temporary Investments	December 31, 2016 Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash (a)	$211.7	$ —	$ —	$211.7
Fixed Income Securities – Mutual Funds (b)	92.7	—	(1.0)	91.7
Equity Securities – Mutual Funds	14.4	13.9	—	28.3
Total Other Temporary Investments	$318.8	$ 13.9	$ (1.0)	$331.7

(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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Proceeds from Investment Sales	$ —	$ —	$ —	$ —
Purchases of Investments	12.0	0.6	13.6	1.6
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, 2017 and 2016, 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 funds 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:

	September 30, 2017			December 31, 2016		
	Fair	Gross Unrealized	Other-Than-Temporary	Fair	Gross Unrealized	Other-Than-Temporary

	Value (in millions)	Gains	Impairments	Value	Gains	Impairments
Cash and Cash Equivalents	$20.5	$ —	$ —	$18.7	$ —	$ —
Fixed Income Securities:						
United States Government	974.3	32.6	(1.9)	785.4	27.1	(5.5)
Corporate Debt	60.0	3.5	(1.2)	60.9	2.3	(1.4)
State and Local Government	9.0	1.0	(0.2)	121.1	0.4	(0.7)
Subtotal Fixed Income Securities	1,043.3	37.1	(3.3)	967.4	29.8	(7.6)
Equity Securities - Domestic	1,369.2	783.1	(75.4)	1,270.1	677.9	(79.6)
Spent Nuclear Fuel and Decommissioning Trusts	$2,433.0	$ 820.2	$ (78.7)	$2,256.2	$ 707.7	$ (87.2)

The following table provides the securities activity within the decommissioning and SNF trusts:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Proceeds from Investment Sales	$519.5	$650.0	$1,808.6	$2,427.0
Purchases of Investments	525.0	656.5	1,842.2	2,452.9
Gross Realized Gains on Investment Sales	9.8	13.9	198.1	41.9
Gross Realized Losses on Investment Sales	5.2	6.5	145.4	22.2

The base cost of fixed income securities was $1 billion and $938 million as of September 30, 2017 and December 31, 2016, respectively. The base cost of equity securities was $586 million and $592 million as of September 30, 2017 and December 31, 2016, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of September 30, 2017 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 403.6
After 1 year through 5 years	287.9
After 5 years through 10 years	184.2
After 10 years	167.6
Total	$ 1,043.3

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 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, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Cash and Cash Equivalents (a)	$—	$—	$—	$343.9	$343.9
Other Temporary Investments					
Restricted Cash (a)	158.6	1.4	—	12.9	172.9
Fixed Income Securities – Mutual Funds	103.2	—	—	—	103.2
Equity Securities – Mutual Funds (b)	34.6	—	—	—	34.6
Total Other Temporary Investments	296.4	1.4	—	12.9	310.7
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	1.2	307.9	300.3	(161.4)	448.0
Cash Flow Hedges:					
Commodity Hedges (c)	—	9.1	1.3	(6.1)	4.3
Interest Rate/Foreign Currency Hedges	—	4.2	—	—	4.2
Total Risk Management Assets	1.2	321.2	301.6	(167.5)	456.5
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	14.0	—	—	6.5	20.5
Fixed Income Securities:					
United States Government	—	974.3	—	—	974.3
Corporate Debt	—	60.0	—	—	60.0
State and Local Government	—	9.0	—	—	9.0
Subtotal Fixed Income Securities	—	1,043.3	—	—	1,043.3
Equity Securities – Domestic (b)	1,369.2	—	—	—	1,369.2
Total Spent Nuclear Fuel and Decommissioning Trusts	1,383.2	1,043.3	—	6.5	2,433.0
Total Assets	$1,680.8	$1,365.9	$301.6	$195.8	$3,544.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$3.2	$306.6	$205.9	$(174.9)	$340.8

Cash Flow Hedges:					
Commodity Hedges (c)	—	35.3	50.7	(6.1)	79.9
Fair Value Hedges	—	1.4	—	—	1.4
Total Risk Management Liabilities	$3.2	$343.3	$256.6	$(181.0)	$422.1

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Cash and Cash Equivalents (a)	$8.7	$—	$—	$201.8	$210.5
Other Temporary Investments					
Restricted Cash (a)	173.8	5.1	—	32.8	211.7
Fixed Income Securities – Mutual Funds	91.7	—	—	—	91.7
Equity Securities – Mutual Funds (b)	28.3	—	—	—	28.3
Total Other Temporary Investments	293.8	5.1	—	32.8	331.7
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	6.0	379.9	192.2	(205.7)	372.4
Cash Flow Hedges:					
Commodity Hedges (c)	—	16.8	1.7	(7.3)	11.2
Total Risk Management Assets	6.0	396.7	193.9	(213.0)	383.6
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	7.3	—	—	11.4	18.7
Fixed Income Securities:					
United States Government	—	785.4	—	—	785.4
Corporate Debt	—	60.9	—	—	60.9
State and Local Government	—	121.1	—	—	121.1
Subtotal Fixed Income Securities	—	967.4	—	—	967.4
Equity Securities – Domestic (b)	1,270.1	—	—	—	1,270.1
Total Spent Nuclear Fuel and Decommissioning Trusts	1,277.4	967.4	—	11.4	2,256.2
Total Assets	$1,585.9	$1,369.2	$193.9	$33.0	$3,182.0
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$8.2	$352.0	$166.7	$(205.4)	$321.5
Cash Flow Hedges:					
Commodity Hedges (c)	—	29.3	24.7	(7.3)	46.7
Fair Value Hedges	—	1.4	—	—	1.4
Total Risk Management Liabilities	$8.2	$382.7	$191.4	$(212.7)	$369.6

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Restricted Cash for Securitized Funding (a)	$8.3	$—	$—	$0.1	$8.4
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	22.2	30.0	(21.3)	30.9
Total Assets	$8.3	$22.2	$30.0	$(21.2)	$39.3
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$21.8	$0.6	$(21.2)	$1.2

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Restricted Cash for Securitized Funding (a)	$15.8	$—	$—	$0.1	$15.9
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	20.5	3.9	(21.8)	2.6
Total Assets	$15.8	$20.5	$3.9	$(21.7)	$18.5
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$20.7	$2.5	$(22.0)	$1.2

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$—	$16.3	$12.4	$(16.6)	$12.1
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	14.0	—	—	6.5	20.5
Fixed Income Securities:					
United States Government	—	974.3	—	—	974.3
Corporate Debt	—	60.0	—	—	60.0
State and Local Government	—	9.0	—	—	9.0
Subtotal Fixed Income Securities	—	1,043.3	—	—	1,043.3
Equity Securities - Domestic (b)	1,369.2	—	—	—	1,369.2
Total Spent Nuclear Fuel and Decommissioning Trusts	1,383.2	1,043.3	—	6.5	2,433.0
Total Assets	$1,383.2	$1,059.6	$12.4	$(10.1)	$2,445.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$16.4	$2.2	$(16.4)	$2.2

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$—	$12.8	$ 3.0	$(12.3)	$3.5
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	7.3	—	—	11.4	18.7
Fixed Income Securities:					
United States Government	—	785.4	—	—	785.4
Corporate Debt	—	60.9	—	—	60.9
State and Local Government	—	121.1	—	—	121.1
Subtotal Fixed Income Securities	—	967.4	—	—	967.4
Equity Securities - Domestic (b)	1,270.1	—	—	—	1,270.1
Total Spent Nuclear Fuel and Decommissioning Trusts	1,277.4	967.4	—	11.4	2,256.2

Total Assets	$1,277.4	$980.2	$3.0	$(0.9)	$2,259.7
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$13.3	$0.2	$(12.4)	$1.1

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OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Restricted Cash for Securitized Funding (a)	$15.6	$—	$—	$—	$15.6
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	0.3	—	(0.1)	0.2
Total Assets	$15.6	$0.3	$—	$(0.1)	$15.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$—	$138.5	$—	$138.5

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Restricted Cash for Securitized Funding (a)	$—	$—	$—	$27.2	$27.2
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	0.4	—	(0.2)	0.2
Total Assets	$—	$0.4	$—	$27.0	$27.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$—	$119.0	$—	$119.0

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PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 4.8	$ (0.1)	$ 4.7
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 0.1	$ (0.1)	$ —

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.2	$ 0.7	$ (0.1)	$ 0.8

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Cash and Cash Equivalents (a)	$—	$—	$—	$2.2	$2.2
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	0.1	13.3	(0.2)	13.2
Total Assets	$—	$0.1	$13.3	$2.0	$15.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$0.1	$0.2	$(0.2)	$0.1

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Cash and Cash Equivalents (a)	$8.7	$—	$—	$1.6	$10.3
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	0.3	0.8	(0.2)	0.9
Total Assets	$8.7	$0.3	$0.8	$1.4	$11.2
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$0.3	$0.1	$(0.1)	$0.3

(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, 2017 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $(2) million in periods 2018-2020; Level 2 matures $(1) million in 2017 and $3 million in periods 2018-2020 and $(1) million in periods 2021-2022; Level 3 matures $23 million in 2017, $77 million in periods 2018-2020, $16 million in periods 2021-2022 and $(21) million in periods

2023-2032. 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, 2016 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $(2) million in periods 2018-2020; Level 2 matures $20 million in 2017, $4 million in periods 2018-2020, $3 million in periods 2021-2022 and $1 million in periods 2023-2032; Level 3 matures $17 million in 2017, $28 million in periods 2018-2020, $11 million in periods 2021-2022 and $(31) million in periods 2023-2032. 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, 2017 and 2016.

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, 2017	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of June 30, 2017	$87.3	$41.3	$15.5	$(130.5)	$9.5	$ 12.4
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	19.8	6.2	3.8	(0.1)	4.0	3.8
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b)	14.8	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(24.3)	—	—	—	—	—
Settlements	(49.2)	(16.2)	(8.4)	1.2	(6.9)	(7.6)
Transfers into Level 3 (d) (e)	5.7	—	—	—	—	—
Transfers out of Level 3 (e)	0.2	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	(9.3)	(1.9)	(0.7)	(9.1)	(1.9)	4.5
Balance as of September 30, 2017	$45.0	$29.4	$10.2	$(138.5)	$4.7	$ 13.1

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)	—	—	—	—	—
Settlements	(37.1)	(17.9)	(5.0)	0.9	(0.7)	(4.4)
Transfers into Level 3 (d) (e)	13.1	0.1	—	—	—	—
Transfers out of Level 3 (e)	(10.0)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	(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

Nine Months Ended September 30, 2017	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of December 31, 2016	$2.5	$1.4	$2.8	$(119.0)	$0.7	$ 0.7
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	37.4	17.2	4.0	(1.0)	3.1	6.0
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b)	37.2	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(29.5)	—	—	—	—	—
Settlements	(49.7)	(18.9)	(7.1)	5.1	(3.8)	(6.8)
Transfers into Level 3 (d) (e)	16.1	—	—	—	—	—
Transfers out of Level 3 (e)	(9.1)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	40.1	29.7	10.5	(23.6)	4.7	13.2
Balance as of September 30, 2017	$45.0	$29.4	$10.2	$(138.5)	$4.7	$ 13.1

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)	—	—	—	—	—
Settlements	(67.1)	(36.2)	(10.3)	4.0	0.4	(8.4)
Transfers into Level 3 (d) (e)	11.2	—	—	—	—	—
Transfers out of Level 3 (e)	1.1	0.1	0.1	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	(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

(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 existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) 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 or accounts payable.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

Significant Unobservable Inputs
September 30, 2017
AEP

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$233.8	$ 252.6	Discounted Cash Flow	Forward Market Price (a)	$(0.05)	$92.77	$ 35.82
				Counterparty Credit Risk (b)	10	539	204
Natural Gas Contracts	0.9	—	Discounted Cash Flow	Forward Market Price (c)	2.47	3.03	2.68
FTRs	66.9	4.0	Discounted Cash Flow	Forward Market Price (a)	(9.80)	9.37	0.32
Total	$301.6	$ 256.6					

Significant Unobservable Inputs
December 31, 2016
AEP

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$183.8	$ 187.1	Discounted Cash Flow	Forward Market Price (a)	$6.51	$86.59	$ 39.40
				Counterparty Credit Risk (b)	35	824	391
FTRs	10.1	4.3	Discounted Cash Flow	Forward Market Price (a)	(7.99)	8.91	0.86
Total	$193.9	$ 191.4					

Significant Unobservable Inputs
September 30, 2017
APCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$1.0	$ 0.4	Discounted Cash Flow	Forward Market Price	$14.85	$45.72	$ 33.99
FTRs	29.0	0.2	Discounted Cash Flow	Forward Market Price	0.08	6.36	1.20
Total	$30.0	$ 0.6					

Significant Unobservable Inputs
December 31, 2016
APCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$0.4	$ 0.4	Discounted Cash Flow	Forward Market Price	$19.68	$48.55	$ 36.34
FTRs	3.5	2.1	Discounted Cash Flow	Forward Market Price	(0.23)	8.91	2.37
Total	$3.9	$ 2.5					

Significant Unobservable Inputs
September 30, 2017
I&M

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$0.6	$ 0.3	Discounted Cash Flow	Forward Market Price	$14.85	$45.72	$ 33.99
FTRs	11.8	1.9	Discounted Cash Flow	Forward Market Price	(0.02)	6.36	0.71
Total	$12.4	$ 2.2					

Significant Unobservable Inputs
December 31, 2016
I&M

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$0.3	$ 0.2	Discounted Cash Flow	Forward Market Price	$19.68	$48.55	$ 36.34
FTRs	2.7	—	Discounted Cash Flow	Forward Market Price	(7.90)	8.91	1.32
Total	$3.0	$ 0.2					

Significant Unobservable Inputs
September 30, 2017
OPCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ —	$ 138.5	Discounted Cash Flow	Forward Market Price (a)	$ 22.89	$ 61.48	$ 41.21
				Counterparty Credit Risk (b)	10	210	150
Total	$ —	$ 138.5					

Significant Unobservable Inputs
December 31, 2016
OPCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ —	$ 119.0	Discounted Cash Flow	Forward Market Price (a)	$ 30.14	$ 71.85	$ 47.45
				Counterparty Credit Risk (b)	47	340	272
Total	$ —	$ 119.0					

Significant Unobservable Inputs
September 30, 2017
PSO

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$ 4.8	$ 0.1	Discounted Cash Flow	Forward Market Price	$ (9.80)	$ 1.03	$ (0.69)

Significant Unobservable Inputs
December 31, 2016
PSO

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$ 0.7	$ —	Discounted Cash Flow	Forward Market Price	$ (7.99)	$ 1.03	$ (0.36)

Significant Unobservable Inputs
September 30, 2017
SWEPCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		Weighted
	Assets	Liabilities	Technique	Input	Low	High	Average
	(in millions)						
Natural Gas Contracts	$0.9	$ —	Discounted Cash Flow	Forward Market Price (c)	$2.47	$3.03	$ 2.68
FTRs	12.4	0.2	Discounted Cash Flow	Forward Market Price (a)	(9.80)	1.03	(0.69)
	$13.3	$ 0.2					

Significant Unobservable Inputs
December 31, 2016
SWEPCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		Weighted
	Assets	Liabilities	Technique	Input (a)	Low	High	Average
	(in millions)						
FTRs	$0.8	$ 0.1	Discounted Cash Flow	Forward Market Price	$(7.99)	$1.03	$ (0.36)

(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 market prices in dollars per MMBtu.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts, Natural Gas Contracts and FTRs for the Registrants as of September 30, 2017 and December 31, 2016:

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.

Effective Tax Rates (ETR)

The interim ETR for AEP's operating companies reflect the estimated annual ETR for 2017 and 2016, adjusted for tax expense associated with certain discrete items. The interim ETR differs from the federal statutory tax rate of 35% primarily due to tax adjustments, state income taxes and other book/tax differences which are accounted for on a flow-through basis.

The ETR from continuing operations for each of the Registrants are included in the following table. Significant variances in the ETR are described below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2017	2016	2017	2016
AEP	33.0%	40.4%	35.3%	(195.6)%
AEPTCo	33.5%	33.5%	33.8%	32.6 %
APCo	33.4%	36.1%	35.5%	36.2 %
I&M	30.6%	31.8%	30.1%	29.5 %
OPCo	36.9%	31.7%	35.6%	33.4 %
PSO	37.2%	37.7%	37.4%	36.8 %
SWEPCo	21.2%	28.9%	25.7%	26.7 %

AEP

Three Months Ended September 30, 2017 Compared to Three Months Ended September 30, 2016

The decrease in the ETR is due to the prior year reversal of a $66 million capital loss valuation allowance related to the pending sale of certain merchant generation assets and prior year tax return adjustments related to the disposition of AEP's commercial barging operations.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

The increase in the ETR is primarily due to the increase in pretax book income driven by the impairment of certain merchant generation assets in the third quarter of 2016. The increase in the ETR is also due to the prior year reversal of a $56 million unrealized capital loss valuation allowance where AEP effectively settled a 2011 audit issue with the IRS, the prior year reversal of a $66 million capital loss valuation allowance related to the pending sale of certain merchant generation assets and prior year tax return adjustments related to the disposition of AEP's commercial barging operations.

APCo

Three Months Ended September 30, 2017 Compared to Three Months Ended September 30, 2016

The decrease in the ETR is primarily due to the recording of favorable federal income tax adjustments and a decrease in pretax book income.

OPCo

Three Months Ended September 30, 2017 Compared to Three Months Ended September 30, 2016

The increase in the ETR is primarily due to changes in other book/tax differences which are accounted for on a flow-through basis and the recording of federal income tax adjustments.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

The increase in the ETR is primarily due to changes in other book/tax differences which are accounted for on a flow-through basis, the recording of federal income tax adjustments and an increase in pretax book income.

SWEPCo

Three Months Ended September 30, 2017 Compared to Three Months Ended September 30, 2016

The decrease in the ETR is primarily due to a $10 million decrease in Income Tax Expense related to income tax benefits attributable to SWEPCo's noncontrolling interest in Sabine.

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. The Joint Committee referred the audit back to the IRS exam team for further consideration. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, the 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, APCo, I&M and OPCo)

Legislation was enacted in the state of Illinois in July 2017 increasing the corporate income tax rate from 5.25% to 7% effective July 1, 2017, with the increased rate applied to the portion of the tax year falling on or after that date. With the inclusion of the 2.5% Illinois Replacement Tax, the total Illinois corporate income tax rate increased from 7.75% to 9.5%, effective July 1, 2017. The legislation is not expected to materially impact net income, cash flows or financial condition.

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:

Type of Debt	September 30, 2017	December 31, 2016	
	(in millions)		
Senior Unsecured Notes	$16,038.6	$ 14,761.0	(b)
Pollution Control Bonds	1,612.4	1,725.1	
Notes Payable	224.5	326.9	
Securitization Bonds	1,449.4	1,705.0	
Spent Nuclear Fuel Obligation (a)	267.9	266.3	
Other Long-term Debt	1,128.9	1,606.9	
Total Long-term Debt Outstanding	20,721.7	20,391.2	(b)
Long-term Debt Due Within One Year	2,359.3	3,013.4	(b)
Long-term Debt	$18,362.4	$ 17,377.8	(b)

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M, a nuclear licensee, has an obligation to the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets related to this obligation were $311 million and $311 million as of September 30, 2017 and December 31, 2016, respectively, and are included in Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets.

(b) 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.

Long-term Debt Activity

Long-term debt and other securities issued, retired and principal payments made during the first nine months of 2017 are shown in the tables below:

Company	Type of Debt	Principal Amount (a)	Interest Rate	Due Date
Issuances:		(in millions)	(%)	
AEPTCo	Senior Unsecured Notes	$ 125.0	3.10	2026
AEPTCo	Senior Unsecured Notes	500.0	3.75	2047
APCo	Senior Unsecured Notes	325.0	3.30	2027
I&M	Pollution Control Bonds	25.0	Variable	2019
I&M	Pollution Control Bonds	40.0	2.05	2021
I&M	Pollution Control Bonds	52.0	Variable	2021
I&M	Senior Unsecured Notes	300.0	3.75	2047
SWEPCo	Other Long-term Debt	115.0	Variable	2020
Non-Registrant:				
AEP Texas	Pollution Control Bonds	60.0	1.75	2020
AEP Texas	Senior Unsecured Notes	400.0	2.40	2022
AEP Texas	Senior Unsecured Notes	300.0	3.80	2047
KPCo	Pollution Control Bonds	65.0	2.00	2020
KPCo	Senior Unsecured Notes	65.0	3.13	2024
KPCo	Senior Unsecured Notes	40.0	3.35	2027
KPCo	Senior Unsecured Notes	165.0	3.45	2029
KPCo	Senior Unsecured Notes	55.0	4.12	2047
Transource Missouri	Other Long-term Debt	7.0	Variable	2018
Transource Energy	Other Long-term Debt	132.1	Variable	2020
Total Issuances		$ 2,771.1		

(a) Amounts indicated on the statements of cash flows are net of issuance costs and premium or discount and will not tie to the issuance amounts.

Company	Type of Debt	Principal Amount Paid	Interest Rate	Due Date
Retirements and Principal Payments:		(in millions)	(%)	
APCo	Senior Unsecured Notes	$ 250.0	5.00	2017
APCo	Securitization Bonds	23.5	2.008	2024
APCo	Pollution Control Bonds	104.4	Variable	2017
I&M	Notes Payable	4.9	Variable	2017
I&M	Pollution Control Bonds	25.0	Variable	2017
I&M	Notes Payable	22.3	Variable	2019
I&M	Notes Payable	23.6	Variable	2019
I&M	Notes Payable	23.9	Variable	2020
I&M	Pollution Control Bonds	52.0	Variable	2017
I&M	Notes Payable	24.3	Variable	2021
I&M	Other Long-term Debt	1.1	6.00	2025
I&M	Pollution Control Bonds	50.0	Variable	2025
OPCo	Securitization Bonds	16.2	0.958	2017
OPCo	Securitization Bonds	22.5	0.958	2018
OPCo	Securitization Bonds	7.6	2.049	2019
OPCo	Other Long-term Debt	0.1	1.149	2028
PSO	Other Long-term Debt	0.3	3.00	2027
SWEPCo	Senior Unsecured Notes	250.0	5.55	2017
SWEPCo	Other Long-term Debt	100.0	Variable	2017
SWEPCo	Other Long-term Debt	0.2	3.50	2023
SWEPCo	Other Long-term Debt	0.1	4.28	2023
SWEPCo	Notes Payable	3.3	4.58	2032
Non-Registrant:				
AEGCo	Senior Unsecured Notes	152.7	6.33	2037
AGR	Other Long-term Debt	500.0	Variable	2017
KPCo	Pollution Control Bonds	65.0	Variable	2017
KPCo	Senior Unsecured Notes	325.0	6.00	2017
TCC	Securitization Bonds	27.2	0.88	2017
TCC	Securitization Bonds	161.2	5.17	2018
TCC	Pollution Control Bonds	60.0	5.20	2030
Transource Missouri	Other Long-term Debt	130.8	Variable	2018
Total Retirements and Principal Payments		$ 2,427.2		

In October 2017, I&M retired $1 million of Notes Payable related to DCC Fuel.

In October 2017, AEP Texas retired $41 million of 5.625% Pollution Control Bonds due in 2017.

As of September 30, 2017, trustees held, on behalf of AEP, $728 million of their reacquired Pollution Control Bonds. Of this total, $104 million, $50 million and $345 million related to APCo, I&M and OPCo, respectively.

Debt Covenants (Applies to AEP and AEPTCo)

Covenants in AEPTCo's note purchase agreements and indenture also limit the amount of contractually-defined priority debt (which includes a further sub-limit of $50 million of secured debt) to 10% of consolidated tangible net assets. The method for calculating the consolidated tangible net assets is contractually defined in the note purchase agreements.

Dividend Restrictions

Utility Subsidiaries' Restrictions

Parent depends on its utility subsidiaries to pay dividends to shareholders. 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.

All of the dividends declared by AEP's utility subsidiaries that provide transmission or local distribution services are subject to a Federal Power Act restriction that prohibits the payment of dividends out of capital accounts without regulatory approval; payment of dividends is allowed out of retained earnings only. 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.

Certain AEP subsidiaries have credit agreements that contain a covenant that limits their debt to capitalization ratio to 67.5%. As of September 30, 2017, no subsidiaries have exceeded their debt to capitalization limit. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization of the AEP subsidiary distributing the dividend. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements.

As of September 30, 2017, the Federal Power Act restriction does not limit the ability of the AEP subsidiaries to pay dividends out of retained earnings.

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%. As of September 30, 2017, AEP has not exceeded its debt to capitalization limit. 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.

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, 2017 and December 31, 2016 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, 2017 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, 2017	Authorized Short-term Borrowing Limit	
	(in millions)						
AEPTCo	$467.2	$ 194.8	$ 235.7	$ 19.3	$ 162.9	$ 795.0	(a)
APCo	231.5	160.7	152.2	32.2	(45.9)	600.0	
I&M	367.4	12.6	205.7	12.6	(164.9)	500.0	
OPCo	280.6	56.2	141.0	27.9	(167.6)	400.0	
PSO	185.2	—	121.3	—	(118.0)	300.0	
SWEPCo	187.5	178.6	109.6	169.5	(48.3)	350.0	

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

The activity in the above table does not include short-term lending activity of SWEPCo's wholly-owned subsidiary, Mutual Energy SWEPCo, LP, which is a participant in the Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of September 30, 2017 and December 31, 2016 are included in Advances to Affiliates on SWEPCo's balance sheets. For the nine months ended September 30, 2017, Mutual Energy SWEPCo, LP had the following activity in the Nonutility Money Pool:

Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of September 30, 2017
(in millions)		
$2.0	$ 2.0	$ 2.0

AEP has a direct financing relationship with AEPTCo to meet its short-term borrowing needs. The amounts of outstanding loans to (borrowings from) AEP as of September 30, 2017 and December 31, 2016 are included in

Advances to Affiliates and Advances from Affiliates, respectively, on AEPTCo's balance sheets. AEPTCo's direct borrowing and lending activity with AEP for the nine months ended September 30, 2017 is described in the following table:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of September 30, 2017	Loans to AEP as of September 30, 2017	Authorized Short-term Borrowing Limit	
(in millions)							
$1.1	$ 151.9	$ 1.1	$ 38.9	$ 0.9	$ 96.1	$ 75.0	(a)

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

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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,	
	2017	2016
Maximum Interest Rate	1.49 %	0.91 %
Minimum Interest Rate	0.92 %	0.69 %

The average interest rates for funds borrowed from and loaned to the Utility Money Pool 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	2017	2016	2017	2016
AEPTCo	1.36 %	0.82 %	1.04 %	0.74 %
APCo	1.24 %	0.78 %	1.28 %	0.79 %
I&M	1.24 %	0.73 %	1.27 %	0.78 %
OPCo	1.40 %	0.85 %	0.98 %	0.74 %
PSO	1.30 %	0.76 %	— %	0.81 %
SWEPCo	1.26 %	0.79 %	0.98 %	0.91 %

Maximum, minimum and average interest rates for funds loaned to the Nonutility Money Pool are summarized for Mutual Energy SWEPCo, LP in the following table:

Nine Months Ended September 30,	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
2017	1.49 %	— %	1.27 %
2016	0.91 %	0.69 %	0.79 %

AEPTCo's maximum, minimum and average interest rates for funds either borrowed from or loaned to AEP are summarized in the following table:

	Maximum Interest Rate	Minimum Interest Rate	Maximum Interest Rate	Minimum Interest Rate	Average Interest Rate	Average Interest Rate
Nine Months	for Funds	for Funds	for Funds	for Funds	for Funds	

Ended September 30,	Borrowed from AEP	Borrowed from AEP	Loaned to AEP	Loaned to AEP	Borrowed from AEP	for Funds Loaned to AEP
2017	1.49 %	0.92 %	1.49 %	0.92 %	1.27 %	1.31 %
2016	0.91 %	0.69 %	0.91 %	0.69 %	0.80 %	0.81 %

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Short-term Debt (Applies to AEP and SWEPCo)

Outstanding short-term debt was as follows:

		September 30, 2017		December 31, 2016	
Company	Type of Debt	Outstanding Amount	Interest Rate (a)	Outstanding Amount	Interest Rate (a)
		(in millions)		(in millions)	
AEP	Securitized Debt for Receivables (b)	$750.0	1.17 %	$673.0	0.70 %
AEP	Commercial Paper	295.0	1.39 %	1,040.0	1.02 %
SWEPCo	Notes Payable	14.3	2.88 %	—	— %
	Total Short-term Debt	$1,059.3		$1,713.0	

(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.

Securitized Accounts 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 2019.

Accounts receivable information for AEP Credit is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(dollars in millions)			
Effective Interest Rates on Securitization of Accounts Receivable	1.33 %	0.73 %	1.17 %	0.65 %
Net Uncollectible Accounts Receivable Written Off	$7.0	$7.7	$18.2	$17.5

	September 30, 2017	December 31, 2016
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$939.8	$ 945.0
Short-term – Securitized Debt of Receivables	750.0	673.0
Delinquent Securitized Accounts Receivable	44.3	42.7
Bad Debt Reserves Related to Securitization	27.8	27.7
Unbilled Receivables Related to Securitization	264.2	322.1

AEP Credit's delinquent customer accounts receivable represent accounts greater than 30 days past due.

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Securitized Accounts Receivables – AEP Credit (Applies to Registrant Subsidiaries, except AEPTCo)

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 was as follows:

Company	September 30, 2017	December 31, 2016
	(in millions)	
APCo	$116.9	$ 142.0
I&M	132.7	136.7
OPCo	356.3	388.3
PSO	143.4	110.4
SWEPCo	167.1	130.9

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	2017	2016	2017	2016
	(in millions)			
APCo	$1.5	$1.6	$4.2	$5.4
I&M	1.8	2.0	4.9	5.6
OPCo	6.1	8.1	16.5	23.4
PSO	2.0	1.8	5.2	4.7
SWEPCo	2.0	2.1	5.4	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	2017	2016	2017	2016
	(in millions)			
APCo	$335.5	$361.7	$1,029.4	$1,071.6
I&M	409.9	448.0	1,218.9	1,220.2
OPCo	616.3	750.9	1,741.7	2,011.2
PSO	407.0	390.6	1,022.6	971.9
SWEPCo	455.0	460.4	1,200.8	1,183.9

CONTROLS AND PROCEDURES

During the third quarter of 2017, 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, 2017, 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 2017 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 AEP 2016 Annual Report on Form 10-K and the AEPTCo 2016 Annual Report included within AEPTCo's Registration Statement includes a detailed discussion of risk factors. As of September 30, 2017, there have been no material changes to the risk factors previously disclosed in AEPTCo's Registration Statement. As of September 30, 2017, the risk factor appearing in AEP's 2016 Annual Report under the heading set forth below is supplemented and updated as follows:

AEP is exposed to nuclear generation risk. (Applies to AEP and I&M)

Through I&M, AEP owns the Cook Plant. It consists of two nuclear generating units for a rated capacity of 2,278 MWs, or about 7% of the generating capacity in the AEP System. AEP and I&M are, therefore, subject to the risks of nuclear generation, which include the following:

- The potential harmful effects on the environment and human health due to an adverse incident/event resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials such as spent nuclear fuel.
- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations.
- Uncertainties with respect to contingencies and assessment amounts triggered by a loss event (federal law requires owners of nuclear units to purchase the maximum available amount of nuclear liability insurance and potentially contribute to the coverage for losses of others).
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.
- Uncertainties related to reliance on a vendor for manufacturing nuclear fuel and for providing specialized engineering services and parts.

There can be no assurance that I&M's preparations or risk mitigation measures will be adequate if these risks are triggered.

The Nuclear Regulatory Commission has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants. In addition, although management has no reason to anticipate a serious nuclear incident at the Cook Plant, if an incident did occur, it could harm results of operations or financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit. Moreover, a major incident at any nuclear facility in the U.S. could require AEP or I&M to make material contributory payments.

Costs associated with the operation (including fuel), maintenance and retirement of nuclear plants continue to be more significant and less predictable than costs associated with other sources of generation, in large part due to changing regulatory requirements and safety standards, availability of nuclear waste disposal facilities and experience gained in the operation of nuclear facilities. Costs also may include replacement power, any unamortized investment at the end of the useful life of the Cook Plant (whether scheduled or premature), the carrying costs of that investment and retirement costs. The ability to obtain adequate and timely recovery of costs associated with the Cook Plant is not assured.

Westinghouse and I&M have a number of significant ongoing contracts relating to reactor services, nuclear fuel fabrication, and ongoing engineering projects. The most significant of these relate to Cook Plant fuel fabrication. In March 2017, Westinghouse filed a petition to reorganize under Chapter 11 of the U.S. Bankruptcy Code. It intends to reorganize, not cease business operations. However, it is in the early stages of the bankruptcy process and it is unclear whether the company can successfully reorganize. In the event Westinghouse rejects I&M's contracts, or is unable to reorganize or sell its profitable businesses in the bankruptcy, Cook Plant's operations would be significantly impacted and potentially shut down temporarily as I&M seeks other vendors for these services.

AEP's transmission investment strategy and execution bears certain risks associated with these activities. (Applies to all Registrants)

Management expects that a growing portion of AEP's earnings in the future will be derived from transmission investments and activities. FERC policy currently favors the expansion and updating of the transmission infrastructure within its jurisdiction. If the FERC were to adopt a different policy, if states were to limit or restrict such policies, or if transmission needs do not continue or develop as projected, AEP's strategy of investing in transmission could be impacted. Management believes AEP's experience with transmission facilities construction and operation gives AEP an advantage over other competitors in securing authorization to install, construct and operate new transmission lines and facilities. However, there can be no assurance that PJM, SPP or other RTOs will authorize new transmission projects or will award such projects to AEP.

In October 2016, several parties filed a joint complaint with the FERC claiming that the base return on common equity used by eastern AEP affiliates in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. In June 2017, several parties filed a joint complaint with the FERC that states the base return on common equity used by western AEP affiliates, including the State Transcos that operate in SPP, in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.36%, effective upon the date of the complaint. If the FERC orders revenue reductions as a result of these complaints, including refunds from the date each complaint was filed, it could reduce future net income and cash flows and impact financial condition.

If the FERC were to lower the rate of return it has authorized for AEP's transmission investments and facilities, or if one or more states were to successfully limit FERC jurisdiction on recovery of costs on transmission investment and its return, it could reduce future net income and cash flows and negatively impact financial condition.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None

Item 3. Defaults Upon Senior Securities

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, a wholly-owned lignite mining subsidiary of SWEPCo, is subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires 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, 2017.

Item 5. Other Information

None

Item 6. Exhibits

The exhibits designated with an (X) in the table below are being filed on behalf of the Registrants.

Exhibit	Description	AEP	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
12	Computation of Consolidated Ratio of Earnings to Fixed Charges	X	X	X	X	X	X	X
31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X	X	X	X	X	X	X
31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X	X	X	X	X	X	X
32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code	X	X	X	X	X	X	X
32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code	X	X	X	X	X	X	X
95	Mine Safety Disclosures							X
101.INS	XBRL Instance Document	X	X	X	X	X	X	X
101.SCH	XBRL Taxonomy Extension Schema	X	X	X	X	X	X	X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	X	X	X	X	X	X	X
101.DEF	XBRL Taxonomy Extension Definition Linkbase	X	X	X	X	X	X	X
101.LAB	XBRL Taxonomy Extension Label Linkbase	X	X	X	X	X	X	X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	X	X	X	X	X	X	X

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

AEP TRANSMISSION COMPANY, LLC
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: October 26, 2017

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