AMERICAN ELECTRIC POWER CO INC
Form 10-Q
October 25, 2018

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, 2018
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
333-221643	AEP TEXAS INC. (A Delaware Corporation)	51-0007707
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 every Interactive Data File required to be submitted 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 such files). Yes x No ¨
Indicate by check mark whether American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 ¨

Smaller reporting company ¨ Emerging growth company ¨

Indicate by check mark whether AEP Texas 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 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

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 Texas 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 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 25, 2018
American Electric Power Company, Inc.	493,108,827 ($6.50 par value)
AEP Texas Inc.	100 ($0.01 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, 2018

Part II. OTHER INFORMATION

This combined Form 10-Q is separately filed by American Electric Power Company, Inc., AEP Texas 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 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.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, hedging activities, asset management and commercial and industrial sales in the deregulated Ohio and Texas markets.
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, is an intermediate holding company that owns seven wholly-owned transmission companies.
AEPTCo Parent	AEP Transmission Company, LLC, the holding company 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.
ALJ	Administrative Law Judge.
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.
ARAM	Average Rate Assumption Method, an IRS approved method used to calculate the reversal of Excess ADIT for ratemaking purposes.
ASC	Accounting Standard Codification.
ASU	Accounting Standards Update.
CAA	Clean Air Act.
CO_2	Carbon dioxide and other greenhouse gases.
Conesville Plant	A generation plant consisting of three coal-fired generating units totaling 1,695 MW located in Conesville, Ohio. The plant is jointly owned by AGR and a non-affiliate entity.
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 VII, DCC Fuel VIII, DCC Fuel IX, DCC Fuel X, DCC Fuel XI and DCC Fuel XII consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.

Desert Sky	Desert Sky Wind Farm, a 168 MW wind electricity generation facility located on Indian Mesa in Pecos County, Texas.

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Term	Meaning
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.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
ETR	Effective tax rates.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP Transmission Holdco and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
Excess ADIT	Excess accumulated deferred income taxes.
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.
Global Settlement	In February 2017, the PUCO approved a settlement agreement filed by OPCo in December 2016 which resolved all remaining open issues on remand from the Supreme Court of Ohio in OPCo’s 2009 - 2011 and June 2012 - May 2015 ESP filings. It also resolved all open issues in OPCo’s 2009, 2014 and 2015 SEET filings and 2009, 2012 and 2013 Fuel Adjustment Clause Audits.
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.
MISO	Midcontinent Independent System Operator.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NO_2	Nitrogen dioxide.
NO_x	Nitrogen oxide.
NSR	New Source Review.

OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.

Term	Meaning
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.
Oklaunion Power Station	A single unit coal-fired generation plant totaling 650 MW located in Vernon, Texas. The plant is jointly owned by AEP Texas, PSO and certain non-affiliated entities.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OSS	Off-System Sales.
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.
Racine	A generation plant consisting of two hydroelectric generating units totaling 47.5 MW located in Racine, Ohio and owned by AGR.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants: AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
Registrants	SEC registrants: AEP, AEP Texas, 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.
ROE	Return on Equity.
RPM	Reliability Pricing Model.
RSR	Retail Stability Rider.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity for AEP and SWEPCo.
SCR	Selective Catalytic Reduction, NO_x reduction technology at Rockport Plant.
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's existing utility operating companies.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Tax Reform	

	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
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.

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Term	Meaning
Transition Funding	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.
Trent	Trent Wind Farm, a 154 MW wind electricity generation facility located between Abilene and Sweetwater in West Texas.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
UMWA	United Mine Workers of America.
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
Wind Catcher Project	Wind Catcher Energy Connection Project, a joint PSO and SWEPCo project that was cancelled in July 2018. The project included 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.

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 2017 Annual Report, but there are others throughout this document which may be identified by words such as “expect,” “anticipate,” “intend,” “plan,” “believe,” “will,” “should,” “ “would,” “project,” “continue” and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, management undertakes no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

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 renewable generation, 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.

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, environmental compliance and Excess ADIT.

Resolution of litigation.

The ability to constrain operation and maintenance costs.

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.

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.

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Accounting pronouncements periodically issued by accounting standard-setting bodies.
Impact of federal tax reform on customer rates, income tax expense and cash flows.
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 2017 Annual Report and in Part II of this report.

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

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

EXECUTIVE OVERVIEW

Customer Demand

AEP's weather-normalized retail sales volumes for the third quarter of 2018 increased by 0.3% compared to the third quarter of 2017. AEP's third quarter 2018 industrial sales increased by 2.4% compared to the third quarter of 2017. The growth in industrial sales was spread across most operating companies and driven by growth in the oil and gas sector. Weather-normalized residential sales decreased 0.8% in the third quarter of 2018 compared to the third quarter of 2017. Weather-normalized commercial sales decreased by 0.5% in the third quarter of 2018 compared to the third quarter of 2017.

AEP's weather-normalized retail sales volumes for the nine months ended September 30, 2018 increased by 1.2% compared to the nine months ended September 30, 2017. AEP's industrial sales volumes for the nine months ended September 30, 2018 increased 2.6% compared to the nine months ended September 30, 2017. The growth in industrial sales was spread across many industries and most operating companies. Weather-normalized residential and commercial sales increased 0.7% and 0.2%, respectively, for the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017.

Wind Catcher Project

In July 2017, PSO and SWEPCo submitted filings with the OCC, LPSC, APSC and PUCT requesting various regulatory approvals needed for the companies to proceed with the Wind Catcher Project. The Wind Catcher Project included the acquisition of a wind generation facility, totaling approximately 2,000 MWs of wind generation, and the construction of a generation interconnection tie-line totaling approximately 350 miles. Total investment for the project was estimated to be $4.5 billion and would serve both retail and FERC wholesale load. PSO and SWEPCo would have had 30% and 70% ownership shares, respectively, in these assets.

In July 2018, the PUCT denied SWEPCo's request for a Certificate of Public Convenience and Necessity to proceed with the Wind Catcher Project. PSO and SWEPCo subsequently cancelled the Wind Catcher Project.

Other Renewable Generation

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 continues to develop its renewable portfolio within the Generation & Marketing segment. Activities include working 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. Generation & Marketing also develops and/or acquires large scale renewable generation projects that are backed with long-term contracts. As of September 30, 2018, subsidiaries within AEP's

Generation & Marketing segment have approximately 400 MWs of contracted renewable generation projects in operation. In addition, as of September 30, 2018, these subsidiaries have approximately 10 MWs of new renewable generation projects under construction with total estimated capital costs of $27 million related to these projects.

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In January 2018, AEP admitted a nonaffiliate as a member of Desert Sky Wind Farm LLC and Trent Wind Farm LLC (collectively "the LLCs") to own and repower Desert Sky and Trent. The nonaffiliated member contributed full turbine sets to each project in exchange for a 20.1% interest in the LLCs. AEP has contributed substantially all of its cash equity capital commitment of $235 million related to its 79.9% share of the LLCs, or 257 MW. The wind farms are fully repowered and in-service as of September 30, 2018. AEP is subject to a put and a call option after certain conditions are met, either of which would liquidate the nonaffiliated member's interest. See Note 13 - Variable Interest Entities for additional information.

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 MWs of wind generation. In April 2018, the Virginia SCC denied APCo's application to acquire the two wind generation facilities. APCo filed a petition for reconsideration with the Virginia SCC, which was denied. In May 2018, the WVPSC also denied APCo's application to acquire the two wind generation facilities.

In September 2018, OPCo, consistent with its commitment in the previously approved PPA application, submitted a filing with the PUCO demonstrating a need for up to 900 MWs of economically beneficial renewable resources in Ohio. This filing was followed by a separate filing for two solar Renewable Energy Purchase Agreements totaling 400 MWs. The solar generation facilities, if approved, are expected to be in-service by the end of 2021.

Federal Tax Reform

In December 2017, Tax Reform legislation was signed into law. Tax Reform includes significant changes to the Internal Revenue Code of 1986, as amended, and had a material impact on the Registrants' financial statements in the reporting period of its enactment. Tax Reform lowered the corporate federal income tax rate from 35% to 21%. Tax Reform provisions related to regulated public utilities generally allow for the continued deductibility of interest expense, impact bonus depreciation for certain property acquired and placed in service after September 27, 2017 and continue certain rate normalization requirements for accelerated depreciation benefits.

The mechanism and time period to provide the benefits of Tax Reform to customers varies by jurisdiction. Tax Reform did not have a material impact on net income in the third quarter of 2018 and is not expected to have a material impact on future net income. However, the Registrants will experience a decrease in future cash flows primarily due to the elimination of bonus depreciation, the reduction in the federal tax rate from 35% to 21% and the flow back of Excess ADIT. Further, the Registrants expect that access to capital markets will be sufficient to satisfy any liquidity needs that result from any such decrease in future cash flows.

Provisional Amounts

The Registrants applied Staff Accounting Bulletin 118 (SAB 118), issued by the SEC staff in December 2017, and made reasonable estimates for the measurement and accounting of the effects of Tax Reform which are reflected in the financial statements as provisional amounts based on the best information available. While the Registrants were able to make reasonable estimates of the impact of Tax Reform in 2017, the final impact may differ from the recorded provisional amounts to the extent refinements are made to the estimated cumulative differences or as a result of additional guidance or technical corrections that may be issued by the IRS that may impact management's interpretation and assumptions utilized. The Registrants expect to complete the analysis of the provisional items during the fourth quarter of 2018.

Reduction in the Corporate Federal Income Tax Rate - Pending Rate Reductions

State utility commissions have issued orders or instructions requiring public utilities, including the Registrants, to record liabilities to reflect the impact of the reduction in the corporate federal income tax rate in excess of the enacted corporate federal income tax rate of 21% beginning in 2018. As described in Note 4 - Rate Matters, certain Registrants

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have received state utility commission orders and have reflected the lower corporate federal income tax rate in current customer rates. As of September 30, 2018, AEP has recorded estimated provisions for revenue refunds totaling $150 million as a result of the reduction in the corporate federal tax rate.

Excess ADIT - Pending Rate Reductions

As of September 30, 2018, the Registrants have approximately $4.3 billion of Excess ADIT, as well as an incremental liability of $1.1 billion to reflect the $4.3 billion Excess ADIT on a pretax basis, presented in Regulatory Liabilities and Deferred Investment Tax Credits on the balance sheets. The Excess ADIT is reflected on a pretax basis to appropriately contemplate future tax consequences in the periods when the regulatory liability is settled. As of September 30, 2018, approximately $3.4 billion of the Excess ADIT relates to temporary differences associated with certain depreciable property subject to rate normalization requirements.

As reflected in the Registrants' respective estimated annual ETR for 2018, AEP's regulated public utilities began amortizing the Excess ADIT associated with certain depreciable property subject to rate normalization requirements using the ARAM during the first quarter of 2018. As a result of state utility commission orders or instructions, the Registrants have recorded estimated provisions for revenue refund offsetting the amortization of the Excess ADIT to the extent not yet reflected in current customer rates. As of September 30, 2018, AEP has recorded estimated provisions for revenue refunds totaling $36 million.

In addition, with respect to the remaining $0.9 billion of Excess ADIT recorded in Regulatory Liabilities and Deferred Investment Tax Credits that are not subject to rate normalization requirements, the Registrants have received state utility commission orders or instructions and a filed FERC settlement agreement to begin amortization.

Merchant Coal Generation Assets

In September 2018, management announced plans to close Oklaunion Power Station by October 2020. In October 2018, management announced plans to close Conesville Plant in May 2020. The closures are not expected to have a material impact on net income, cash flows or financial condition.

Racine

A project to reconstruct a defective dam structure at Racine began in the first quarter of 2017. In December 2017, an impairment analysis was triggered by the expected costs of the dam reconstruction activities, resulting in a pretax impairment charge equal to Racine's net book value of $43 million as of December 31, 2017.

Construction activities at Racine continued through 2018, accumulating new capital expenditures of $35 million as of September 30, 2018. Due to a significant increase in estimated costs to complete the reconstruction project, in the third quarter of 2018, an impairment analysis was performed resulting in an impairment of $35 million. AEP expects to incur additional capital expenditures to complete the reconstruction project, at which point the fair value of Racine, as fully operational, is expected to approximate the amount of those remaining estimated capital expenditures. Future revisions in cost estimates could result in additional losses which could reduce future net income and cash flows.

Hurricane Harvey

In August 2017, Hurricane Harvey hit the coast of Texas, causing power outages in the AEP Texas service territory. Rebuilding efforts are expected to continue through the end of 2018 and AEP Texas' total costs related to this storm are not yet final. AEP Texas has a PUCT approved catastrophe reserve which allows for the deferral of incremental storm expenses as a regulatory asset, and currently recovers approximately $1 million of storm costs annually through base rates. As of September 30, 2018, the total balance of AEP Texas' regulatory asset for deferred storm costs is approximately $150 million, inclusive of approximately $127 million of incremental storm expenses related to Hurricane Harvey. As of September 30, 2018, AEP Texas has recorded approximately $205 million of capital expenditures related to Hurricane Harvey. Also, as of September 30, 2018, AEP Texas has received $10 million in insurance proceeds, and has recorded a receivable for an additional $4 million that will be received in the fourth quarter of 2018, which were applied to the Hurricane Harvey related regulatory asset and property, plant and equipment balances. Management, in conjunction with the insurance adjusters, is reviewing all damages to determine the extent of coverage for additional insurance reimbursement. Any future insurance recoveries received will be applied to, and will offset, the regulatory asset and property, plant and equipment, as applicable.

Management believes the amount recorded as a regulatory asset is probable of recovery and is in the process of requesting securitization of the distribution portion of the regulatory asset. The standard process for securitization of storm cost recovery in Texas requires two filings with the PUCT. In August 2018, AEP Texas filed a Determination of System Restoration Costs with the PUCT for total estimated storm costs in the amount of $425 million, which includes estimated carrying costs. The estimated value of the total storm costs net of insurance proceeds, tax credits and Excess ADIT is $370 million. AEP Texas intends to request securitization for distribution related assets of $253 million while the remaining $117 million of transmission related assets will be recovered through interim transmission filings or an upcoming base rate case. The request for securitization is expected to occur by the first quarter of 2019.

In October 2018, intervenors filed testimony requesting a $24 million reduction in AEP Texas' Determination of System Restoration Costs. Also in October 2018, the PUCT staff filed testimony requesting a $4 million reduction AEP Texas' Determination of System Restoration Costs. Settlement negotiations are ongoing. 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.

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

In April 2018, the PUCO issued an order approving the ESP extension through May 2024 which includes: (a) an extension of the OVEC PPA rider, (b) a 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) revenue 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, effective June 1, 2018, based on a depreciation study using data through December 2015 and (g) amortization of approximately $24 million annually beginning June 2018 of OPCo's excess distribution accumulated depreciation reserve, which was $239 million as of December 31, 2015. Upon the issuance of the PUCO order, OPCo stopped recording $39 million in annual amortization of excess distribution accumulated depreciation reserve in June 2018, which was previously approved to end in December 2018 in accordance with PUCO's December 2011 OPCo distribution base rate case order. OPCo and intervenors agreed 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 May 2018, OPCo and various intervenors filed requests for rehearing with the PUCO. In June 2018, these requests for rehearing were approved to allow further consideration of the requests. In August 2018, the PUCO denied all requests for rehearing. In October 2018, an intervenor filed an appeal with the Ohio Supreme Court challenging various approved riders. See "Ohio Electric Security Plan Filings" section of Note 4 for additional information.

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.

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In January 2018, the PUCO staff filed testimony that OPCo did not have significantly excessive earnings. Also in January 2018, an intervenor filed testimony recommending a $53 million refund to customers. In February 2018, OPCo and PUCO staff filed a stipulation agreement in which both parties agreed that OPCo did not have significantly excessive earnings in 2016.

A 2016 SEET hearing was held in April 2018 and management expects to receive an order in the first half of 2019. While 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 proposed SEET adjustments, including treatment of the Global Settlement issues described above, adjust the comparable risk group or adopt a different 2016 SEET threshold. If the PUCO orders a refund of 2016 OPCo earnings, it could negatively affect future SEET filings, reduce future net income and cash flows and impact financial condition. See "2016 SEET Filing" section of Note 4 for additional information.

Rockport Plant, Unit 2 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. 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 and is expected to be placed in service in May 2020. The estimated cost of the SCR project is $274 million, excluding AFUDC, to be shared equally between I&M and AEGCo. The filing included a request for authorization for I&M to defer its Indiana jurisdictional ownership share of costs including investment carrying costs 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.

In March 2018, the IURC issued an order approving: (a) the CPCN, (b) the $274 million estimated cost of the SCR, excluding AFUDC, (c) deferral of the Indiana jurisdictional ownership share of costs, including investment carrying costs, (d) depreciation of the SCR asset over 10 years and (e) recovery of these costs using an I&M Indiana rider.

In April 2018, a group of intervenors filed a Petition for Reconsideration and Rehearing of the March 2018 IURC order. In June 2018, the IURC denied the Petition for Reconsideration and Rehearing.

Management intends to request recovery of the Michigan jurisdictional share of the SCR project in a future base rate case. The AEGCo ownership share of the SCR project will be billable under the Rockport UPA to I&M and KPCo and will be subject to future regulatory approval for recovery.

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.

In February 2018, I&M filed a Stipulation and Settlement Agreement for a $97 million annual increase in Indiana rates effective July 1, 2018 subject to a temporary offsetting reduction to customer bills through December 2018 for a credit rider related to the timing of estimated in-service dates of certain capital expenditures. The difference between I&M's requested $263 million annual increase and the $97 million annual increase in the Stipulation and Settlement Agreement

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is primarily a result of: (a) the reduction in the federal income tax rate due to Tax Reform, (b) the feedback of credits for Excess ADIT, (c) a 9.95% return on equity, (d) longer recovery periods of regulatory assets, (e) lower depreciation expense primarily for meters, (f) an increase in the sharing of off-system sales margins with customers from 50% to 95% and (g) a refund of $4 million from July through December 2018 for the impact of Tax Reform for the period January 2018 through June 2018.
In May 2018, the IURC issued an order approving the Stipulation and Settlement Agreement in its entirety.
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 included $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.

In February 2018, an MPSC ALJ issued a Proposal for Decision and recommended an annual revenue increase of $49 million, including an intervenor's proposal for up to 10% of I&M's Michigan retail customers to choose an alternate supplier for generation and a proposed capacity rate based on PJM's net cost of new entry value of $289/MW-day, as well as the MPSC staff's recommended calculation of depreciation expense for both units of Rockport Plant through 2028 and a return on common equity of 9.8%. If the maximum 10% of customers choose an alternate supplier starting in February 2019, the estimated annual pretax loss due to the reduced capacity rate would be approximately $9 million. In October 2018, I&M filed a request with the MPSC seeking authority to defer costs related to customers choosing an alternate supplier starting in February 2019.

In April 2018, the MPSC issued an order that generally approved the ALJ proposal resulting in an annual revenue increase of $50 million, effective April 2018 based on a 9.9% return on common equity. The MPSC also approved the ALJ's recommendation related to the capacity rate.

In May 2018, I&M filed a Petition for Rehearing on the capacity rate issue. In June 2018, the MPSC denied I&M's request.

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%). Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. In June 2010, in response to an Arkansas Supreme Court decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This share of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the wholesale market. Approximately 80% of the Turk Plant investment is recovered under cost-based rate recovery in Texas, Louisiana and through SWEPCo's wholesale customers under FERC-based rates. As of September 30, 2018, the net book value of Turk Plant was $1.5 billion, before cost of removal, including materials and supplies inventory and CWIP. If SWEPCo cannot ultimately recover its investment and expenses related to the Turk Plant, it could reduce future net income and cash flows and impact financial condition.

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2012 Texas Base Rate Case

In July 2018, the Texas Third Court of Appeals reversed the PUCT's judgment affirming the prudence of the Turk Plant and remanded the issue back to the PUCT. In August 2018, SWEPCo filed a Motion for Reconsideration at the Court of Appeals. In October 2018, the Court of Appeals denied SWEPCo's request. SWEPCo intends to file an appeal with the Texas Supreme Court in the fourth quarter of 2018. 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. See "2012 Texas Base Rate Case" section of Note 4.

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 January 2018, the PUCT issued a final order approving a net increase in Texas annual revenues of $50 million based upon a return on common equity of 9.6%, effective May 2017. The final order also included: (a) approval to recover the Texas jurisdictional share of environmental investments placed in service, as of June 30, 2016, at various plants, including Welsh Plant, Units 1 and 3, (b) approval of recovery of, but no return on, the Texas jurisdictional share of the net book value of Welsh Plant, Unit 2, (c) approval of $2 million in additional vegetation management expenses and (d) the rejection of SWEPCo's proposed transmission cost recovery mechanism.

As a result of the final order, in 2017 SWEPCo: (a) recorded an impairment charge of $19 million, which included $7 million associated with the lack of return on Welsh Plant, Unit 2 and $12 million related to other disallowed plant investments, (b) recognized $32 million of additional revenues, for the period of May 2017 through December 2017, that will be surcharged to customers and (c) recognized an additional $7 million of expenses consisting primarily of depreciation expense and vegetation management expense, offset by the deferral of rate case expense. SWEPCo implemented new rates in February 2018 billings. The $32 million of additional 2017 revenues will be collected by the end of 2018. In March 2018, the PUCT clarified and corrected portions of the final order, without changing the overall decision or amounts of the rate change. The order has been appealed by various intervenors.

In April 2018, SWEPCo made an income tax rate refund tariff filing which includes an annual revenue reduction of approximately $18 million to reflect the difference between rates collected under the final order and the rates that would be collected under Tax Reform. The filing did not address the return of Excess ADIT benefits to customers. In June 2018, the ALJ issued an order approving interim rates that provided for a reduction of residential rates of $8 million. In September 2018, the ALJ issued an order approving interim rates for the remaining customers. The matter has been sent to the PUCT for final approval.

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. 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. These environmental costs are subject to prudence review by the LPSC. In May 2018, LPSC staff filed testimony that the environmental control investment for Welsh Plant, Units 1 and 3 and Flint Creek power plants is prudent. In August 2018, the LPSC issued an order affirming prudence and approved the settlement agreement for the environmental control investment. In October 2018, the LPSC staff filed a report approving the $31 million increase as filed. The net annual increase is subject to refund pending commission approval. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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2018 Louisiana Formula Rate Filing

In April 2018, SWEPCo filed its formula rate plan for test year 2017 with the LPSC. The filing included a net $28 million annual increase, which was effective August 2018 and includes SWEPCo's Louisiana jurisdictional share of Welsh Plant and Flint Creek Plant environmental controls. The filing also included a reduction in the federal income tax rate due to Tax Reform but did not address the return of Excess ADIT benefits to customers.

In July 2018, SWEPCo made a supplemental filing to its formula rate plan with the LPSC to reduce the requested annual increase to $18 million. The difference between SWEPCo's requested $28 million annual increase and the $18 million annual increase in the supplemental filing is primarily the result of the return of Excess ADIT benefits to customers.
In October 2018, the LPSC staff issued a recommendation that SWEPCo refund $11 million of excess federal income taxes collected, as a result of Tax Reform, from January 1, 2018 through July 31, 2018. A decision by the LPSC is expected in the fourth quarter of 2018.

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

2018 Oklahoma Base Rate Case

In October 2018, PSO filed a request with the OCC for an $88 million annual increase in Oklahoma retail rates based upon a 10.3% return on common equity. PSO also proposed to implement a performance based rate plan that combines a formula rate with a set of customer-focused performance incentive measures related to reliability, public safety, customer satisfaction and economic development. The proposed annual increase includes $13 million related to increased annual depreciation rates and $7 million related to increased storm expense amortization. The requested increase in annual depreciation rates includes the recovery of Oklaunion Power Station through 2028 (currently being recovered in rates through 2046). Management has announced plans to retire Oklaunion Power Station by October 2020. 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 January 2018, the KPSC issued an order approving a non-unanimous settlement agreement with certain modifications resulting in an annual revenue increase of $12 million, effective January 2018, based on a 9.7% return on equity. The KPSC's primary revenue requirement modification to the settlement agreement was a $14 million annual revenue reduction for the decrease in the corporate federal income tax rate due to Tax Reform. The KPSC approved: (a) the deferral of a total of $50 million of Rockport Plant UPA expenses for the years 2018 through 2022, with the manner and timing of recovery of the deferral to be addressed in KPCo's next base rate case, (b) the recovery/return of 80% of certain annual PJM OATT expenses above/below the corresponding level recovered in base rates, (c) KPCo's commitment to not file a base rate case for three years with rates effective no earlier than 2021 and (d) increased depreciation expense based upon updated Big Sandy Plant, Unit 1 depreciation rates using a 20-year depreciable life.

In February 2018, KPCo filed with the KPSC for rehearing of the January 2018 base case order and requested an additional $2.3 million of annual revenue increases related to: (a) the calculation of federal income tax expense, (b) recovery of purchased power costs associated with forced outages and (c) capital structure adjustments. Also in February 2018, an intervenor filed for rehearing recommending that the reduced corporate federal income tax rate be reflected in lower purchased power expense related to the Rockport UPA.

In April 2018, KPCo and the intervenor filed a settlement agreement with the KPSC in which KPCo withdrew its requested increase related to the recovery of purchased power costs associated with forced outages and the intervenor withdrew its claim regarding the impact of the reduced corporate federal income tax rates on purchased power costs related to the Rockport UPA.

In June 2018, the KPSC issued an order approving the settlement agreement including KPCo's requested additional revenue increase of $765 thousand related to the calculation of federal income tax expense. This rate increase was effective June 28, 2018.

Virginia Legislation Affecting Earnings 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 were frozen until after the Virginia SCC ruled on APCo's next biennial review. These amendments also precluded the Virginia SCC from performing biennial reviews of APCo's earnings for the years 2014 through 2017.

In March 2018, new Virginia legislation impacting investor-owned utilities was enacted, effective July 1, 2018, that: (a) on a one-time basis, required APCo to exclude $10 million of incurred fuel expenses from the July 2018 over/under recovery calculation, (b) reduced APCo's base rates by $50 million annually effective July 30, 2018, on an interim basis and subject to true-up, to reflect the reduction in the federal income tax rate due to Tax Reform, (c) will require APCo to file its next generation and distribution base rate case by March 31, 2020 using 2017, 2018 and 2019 test years ("triennial review"), (d) will require an adjustment in APCo's base rates on April 1, 2019 to reflect actual annual reductions in corporate income taxes due to Tax Reform, (e) will require APCo to seek approval from the Virginia SCC for energy efficiency programs with projected costs in the aggregate of at least $140 million over the 10-year period ending July 1, 2028 and (f) will require APCo to construct and/or acquire solar generation facilities in Virginia, as approved by the Virginia SCC, of at least 200 MW of aggregate capacity by July 1, 2028. Triennial reviews are subject to an earnings test which provides that 70% of any over earnings would be refunded or may be reinvested in approved energy distribution grid transformation projects and/or new utility-owned solar and wind generation facilities. The Virginia SCC's triennial review of 2017-2019 APCo earnings could reduce future net income and cash flows and impact financial condition.

2018 West Virginia Base Rate Case

In May 2018, APCo and WPCo filed a joint request with the WVPSC to increase their combined West Virginia base rates by $115 million ($98 million related to APCo) annually based on a 10.22% return on common equity. The proposed annual increase includes $32 million ($28 million related to APCo) due to increased annual depreciation rates and also reflects the impact of the reduction in the federal income tax rate due to Tax Reform. In October 2018, APCo and WPCo filed updated schedules supporting a $95 million ($80 million related to APCo) annual increase in West Virginia base rates primarily due to the impact of the approved settlement agreement with the WVPSC. See "West Virginia Tax Reform" section of Note 4 for additional information.

In October 2018, WVPSC staff and intervenors filed testimony. WVPSC staff recommended a $2 million annual net revenue increase based on a 9.25% return on common equity while intervenors recommended a $14 million annual net revenue decrease based on an 8.75% return on common equity. The difference between APCo and WPCo's requested annual base rate increase and the WVPSC staff and intervenors recommendations are primarily due to: (a) a reduction in the requested return on common equity, (b) the rejection of updates to the rate base calculation methodology, (c) the rejection of updates to rate base for certain known plant in service increases in 2018 and (d) a reduction in annual depreciation rates primarily related to continuing with a 2040 retirement date for Clinch River Plant rather than APCo's proposed retirement date of 2025. A hearing at the WVPSC is scheduled for November 2018. If 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 PJM Participants

In October 2016, seven parties filed a complaint at the FERC that alleged the base return on common equity used by AEP's transmission owning subsidiaries within PJM 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 November 2017, a FERC order set the matter for hearing and settlement procedures. In March 2018, AEP's transmission owning subsidiaries within PJM and six of the complainants filed a settlement agreement with the FERC (the seventh complainant abstained). If approved by the FERC the settlement agreement: (a) establishes a base ROE for AEP's transmission owning subsidiaries within PJM of 9.85% (10.35% inclusive of the RTO incentive adder of 0.5%), effective January 1, 2018, (b) requires AEP's transmission owning subsidiaries within PJM to provide a one-time refund of $50 million, attributable from the date of the complaint through December 31, 2017, which was credited to customer bills in the second quarter of 2018 and (c) increases the cap on the equity portion of the capital structure to 55% from 50%. As part of the settlement agreement, AEP's transmission owning subsidiaries within PJM also filed updated transmission formula rates incorporating the reduction in the corporate federal income tax rate due to Tax Reform, effective January 1, 2018 and providing for the amortization of the portion of the Excess ADIT that is not subject to the normalization method of accounting, ratably over a ten-year period through credits to the federal income tax expense component of the revenue requirement. In April 2018, an ALJ accepted the interim settlement rates, which included the $50 million one-time refund that occurred in the second quarter of 2018. These interim rates are subject to refund or surcharge, with interest.

In April 2018, certain intervenors filed comments at the FERC recommending a base ROE of 8.48% and a one-time refund of $184 million. The FERC trial staff filed comments recommending a base ROE of 8.41% and one-time refund of $175 million. Another intervenor recommended the refund be calculated in accordance with the base ROE that will ultimately be approved by the FERC. In May 2018, management filed reply comments providing further support for the 9.85% base ROE agreed to in the settlement agreement.

If the FERC orders revenue reductions in excess of the terms of the settlement agreement, it could reduce future net income and cash flows and impact financial condition. A decision from the FERC is pending.

Modifications to AEP's PJM Transmission Rates

In November 2016, AEP's transmission owning subsidiaries within PJM 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. The modified PJM OATT formula rates are based on projected calendar year financial activity and projected plant balances. In December 2017, AEP's transmission owning subsidiaries within PJM filed an uncontested settlement agreement with the FERC resolving all outstanding issues. In April 2018, the FERC approved the uncontested settlement agreement and rates were implemented effective January 1, 2018.

FERC Transmission Complaint - AEP's SPP Participants

In June 2017, several parties filed a complaint at the FERC that states the base return on common equity used by AEP's transmission owning subsidiaries within 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 through September 5, 2018. In November 2017, a FERC order set the matter for hearing and settlement procedures. The parties were unable to settle and the proceeding is currently in the hearing phase.

In September 2018, the same parties filed another complaint at the FERC that states the base return on common equity used by AEP's transmission owning subsidiaries within SPP in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.71%, effective upon the date of the second complaint.

Management believes its financial statements adequately address the impact of these complaints. If the FERC orders revenue reductions as a result of these complaints, including refunds from the date of the complaint filings, it could reduce future net income and cash flows and impact financial condition.

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Modifications to AEP's SPP Transmission Rates

In October 2017, AEP's transmission owning subsidiaries within SPP filed an application at the FERC to modify the SPP OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to projected expenses. The modified SPP OATT formula rates are based on projected calendar year financial activity and projected plant balances. In December 2017, the FERC accepted the proposed modifications effective January 1, 2018, subject to refund, and set this matter for hearing and settlement procedures. 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.

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 $550 million, excluding AFUDC. As of September 30, 2018, SWEPCo had incurred costs of $399 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, 2018, the total net book value of Welsh Plant, Units 1 and 3 was $621 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 April 2017, the LPSC approved recovery of $131 million in investments related to its Louisiana jurisdictional share of environmental controls installed at Welsh Plant, effective May 2017. SWEPCo's approved Louisiana jurisdictional share of Welsh Plant deferrals: (a) are $10 million, excluding $6 million of unrecognized equity as of September 30, 2018, (b) is subject to review by the LPSC and (c) includes a WACC return on environmental investments and the related depreciation expense and taxes. See "2017 Louisiana Formula Rate Filing" and "2018 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. See "Welsh Plant - Environmental Impact" section of Note 4 for additional information.

Westinghouse Electric Company Bankruptcy Filing

In March 2017, Westinghouse filed a petition to reorganize under Chapter 11 of the U.S. Bankruptcy Code. 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. As part of the reorganization, the bankruptcy court approved Westinghouse's sale of its nuclear business to Brookfield WEC Holdings (Brookfield), a nonaffiliated third party. Pursuant to the sale, Brookfield will assume all of I&M's contracts with Westinghouse. In August 2018, the sale closed.

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 and Note 5 – Commitments, Guarantees and Contingencies. 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 the U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it would 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 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.

AEGCo and I&M sought and were granted dismissal of certain of the plaintiffs' claims, including claims for compensatory damages, breach of contract, breach of the implied covenant of good faith and fair dealing and indemnification of costs. 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. Plaintiffs voluntarily dismissed the surviving claims with prejudice, and the court issued a final judgment. The plaintiffs subsequently filed an appeal in the U.S. Court of Appeals for the Sixth Circuit on whether the trial court erred in dismissing plaintiffs' claims for breach of contract and breach of the implied 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 in part. In June 2017, on rehearing, the court of appeals issued an amended opinion reversing the district court's dismissal of certain of plaintiffs' claims for breach of contract, vacating the denial of the plaintiffs' motion for partial summary judgment and remanding the case to the district court for further proceedings. The amended opinion and judgment affirmed 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 removed 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 in the original NSR litigation, seeking to modify the consent decree to eliminate the obligation to install certain 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. Responsive and supplemental filings have been made by all parties. In November 2017, the district court granted the owners' unopposed motion to stay the lease litigation to afford time for resolution of AEP's motion to modify the consent decree. See "Proposed Modification of the NSR Litigation Consent Decree" section below for additional information. In September 2018, the district court granted AEP's unopposed motion to stay further proceedings regarding the consent decree to facilitate settlement discussions among the parties to 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 by-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.

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 below 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, 2018, the AEP System had a total generating capacity of approximately 25,600 MWs, of which approximately 13,500 MWs were 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 $650 million to $1.5 billion through 2025.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in finalizing proposed rules or 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, (g) the outcome of the pending motion to modify the NSR consent decree and (h) 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 previously retired that have a remaining net book value. As of September 30, 2018, the net book value before cost of removal, including related materials and supplies inventory, of the plants/units listed below was $190 million. Management is seeking or will seek recovery of the remaining net book value of $190 million in future rate proceedings.

Company	Plant Name and Unit	Generating Capacity (in MWs)	Amounts Pending Regulatory Approval (in millions)
APCo	Kanawha River Plant	400	$ 44.8
APCo	Clinch River Plant, Unit 3	235	32.6
APCo (a)	Clinch River Plant, Units 1 and 2	470	31.8
APCo	Sporn Plant, Units 1 and 3	300	17.2
APCo	Glen Lyn Plant	335	13.4
SWEPCo	Welsh Plant, Unit 2	528	50.6
Total		2,268	$ 190.4

(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.

To the extent existing generation assets are not recoverable, it could materially reduce future net income and cash flows and impact financial condition.

Proposed Modification of the NSR Litigation Consent Decree

In 2007, the U.S. District Court for the Southern District of Ohio approved a consent decree between 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 they 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 other parties to the consent decree opposed AEP's motion. The district court granted AEP's request to delay the deadline to install SCR technology at Rockport Plant, Unit 2 until June 2020.

In January 2018, AEP filed a supplemental motion proposing to install the SCR at Rockport Plant, Unit 2 and achieve the final SO_2 emission cap applicable to the plant under the consent decree by the end of 2020, before the expiration of the initial lease term. Since all required emission reductions would be achieved, no unit retirements or other compensating measures were offered to maintain the benefits of the current consent decree. Responsive filings were filed in February 2018 by parties opposing AEP's proposed modifications to the consent decree. AEP filed a detailed statement of the specific relief requested to address the changed circumstances at Rockport Plant, Unit 2, and the opposing parties responded thereto. In September 2018, the district court granted AEP's unopposed motion to stay further proceedings on the pending motion to modify the consent decree to facilitate settlement discussions among the parties.

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.

NAAQS

The Federal EPA issued new, more stringent NAAQS for SO_2 in 2010, PM in 2012 and ozone in 2015; the existing standards for NO_2 were retained after review by the Federal EPA in 2018. Implementation of these standards is underway. In December 2017, the Federal EPA published final designations for certain areas' compliance with the 2010 SO_2 NAAQS. Additional designations will be made in 2020. States may develop additional requirements for AEP's facilities as a result of these designations. In June 2018, the Federal EPA proposed to retain the current primary standard for SO_2 of 75 parts per billion, without change.

In December 2016, the Federal EPA completed an integrated review plan for the 2012 PM standard. Work is currently underway on scientific, risk and policy assessments necessary to develop a proposed rule, which is anticipated in 2021.

Most areas of the country were designated attainment or unclassifiable for the 2015 ozone standard in November 2017. The Federal EPA finalized nonattainment designations for the remaining areas in April and July 2018. The Federal EPA has also issued information to assist the states in developing plans that address their obligations under the interstate transport provisions of the CAA for the 2008 and 2015 ozone standards. The Federal EPA has confirmed that for states included in the CSAPR program, there are no additional interstate transport obligations, as all areas of the country are expected to attain the 2008 ozone standard before 2023. State implementation plans for the 2015 ozone standard are due in October 2018. The Federal EPA had 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. In June 2018, the court lifted the stay, allowing those challenges to proceed. 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) would 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.

In March 2012, the Federal EPA proposed disapproval of a portion of the regional haze SIP in Arkansas. 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 planned environmental controls to address other CAA requirements. In September 2016, the Federal EPA published a final FIP, retaining its BART determinations, but accelerating the schedule for implementation of certain required controls. The final rule is being challenged in the U.S. Court of Appeals for the Eighth Circuit, but has been held in abeyance to allow the parties to engage in settlement negotiations. Arkansas and other affected parties filed motions to stay the compliance deadlines pending further action from the Federal EPA and the motion was granted. 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 approved the revision. Arkansas finalized a separate action to revise the SO_2 BART determinations which has been challenged before the Arkansas Pollution Control and Ecology Commission. Management cannot predict the outcome of these proceedings.

The Federal EPA also disapproved portions of the Texas regional haze SIP and promulgated a final FIP that did not include any BART determinations in January 2016. That rule was challenged in the U.S. Court of Appeals for the Fifth Circuit and in March 2017, the court 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. The proposed source-specific approach for Welsh Plant, Unit 1 called for installation of a wet FGD system. In October 2017, the Federal EPA finalized a FIP that allows participation in the CSAPR ozone season program to satisfy the NO_x regional haze obligations for electric generating units in Texas. Additionally, the Federal EPA finalized an intrastate SO_2 emissions trading program based on CSAPR allowance allocations as an alternative to source-specific SO_2 requirements. 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. A challenge to the FIP has been filed in the U.S. Court of Appeals for the Fifth Circuit by various intervenors. The Federal EPA and petitioners filed a joint motion to hold the case in abeyance pending the Federal EPA's review of challengers' petition for reconsideration. In March 2018, that motion was granted. In August 2018, the Federal EPA proposed to affirm its October 2017 FIP approval and requested comment on certain aspects of the FIP promulgation and specifically on the intrastate SO_2 trading program. Management supports the intrastate trading program contained in the FIP as a compliance alternative to source-specific controls.

In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the CSAPR trading programs to use those programs in place of source-specific BART for SO_2 and NO_x emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. The rule was challenged in the U.S. Court of Appeals for the District of Columbia Circuit. The Federal EPA confirmed in 2017 that changes to the CSAPR program, including the removal of Texas sources, did not alter that conclusion. In March 2018, the U.S. Court of Appeals for the District of Columbia Circuit affirmed the Federal EPA rule that found that CSAPR provides greater visibility improvements than BART. Challenges to the changes made to the scope of the program in 2016 are being held in abeyance while the Federal EPA reconsiders the Texas SO_2 BART FIP.

CSAPR

In 2011, the Federal EPA issued CSAPR as a replacement for the Clean Air Interstate Rule, 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 rule was vacated, but that decision was reversed on appeal to the U.S. Supreme Court. On remand, the U.S. Court of Appeals for the District of Columbia Circuit allowed 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 court found that the Federal EPA over-controlled the SO_2 and/or NO_x budgets of 14 states. The court remanded the rule to the Federal EPA for revision consistent with the court's opinion while CSAPR remained in place.

In October 2016, the Federal EPA issued a final rule to address the remand and to incorporate additional changes necessary to address the 2008 ozone standard. The final rule significantly reduced ozone season budgets in many states and discounted 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. In March 2018, the U.S. Court of Appeals for the District of Columbia Circuit denied the petitions and other challenges to the rule. Management has been complying with the more stringent ozone season budgets while these petitions were pending.

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 established 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 proposed 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.

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 court remanded the MATS rule to the Federal EPA to consider costs in determining whether to regulate emissions of HAPs from power plants. The Federal EPA issued a supplemental finding concluding that, after considering the costs of compliance, it was appropriate and necessary to regulate HAP emissions from coal-fired and oil-fired units. Petitions for review of the Federal EPA's 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, which remains in effect.

Climate Change, CO_2 Regulation and Energy Policy

In October 2015, the Federal EPA published the final CO_2 emissions standards for new, modified and reconstructed fossil fuel fired steam generating units and combustion turbines, and final guidelines for the development of state plans to regulate CO_2 emissions from existing sources, known as the Clean Power Plan (CPP).

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 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 of any resulting rulemaking. The U.S. Court of Appeals for the District

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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. In December 2017, the Federal EPA issued an advanced notice of proposed rulemaking seeking information that should be considered by the Federal EPA in developing revised guidelines for state programs. In August 2018, the Federal EPA proposed the Affordable Clean Energy (ACE) rule to replace the CPP with new emission guidelines for regulating CO_2 from existing sources. ACE would establish a framework for states to adopt standards of performance for utility boilers based on heat rate improvements for such boilers. Comments on the proposed ACE rule will be accepted until the end of October 2018. Management is actively monitoring these rulemakings and participating in the development of any new guidelines.

AEP has taken action to reduce and offset CO_2 emissions from its generating fleet and expects CO_2 emissions from its operations to continue to decline due to the retirement of some of its coal-fired generation units, and actions taken to diversify the generation fleet and increase energy efficiency where there is regulatory support for such activities. 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, power purchases and broadening AEP System's portfolio of energy efficiency programs.

In February 2018, AEP announced new intermediate and long-term CO_2 emission reduction goals, based on the output of the company's integrated resource plans, which take into account economics, customer demand, grid reliability and resiliency, regulations and the company's current business strategy. The intermediate goal is a 60% reduction from 2000 CO_2 emission levels from AEP generating facilities by 2030; the long-term goal is an 80% reduction of CO_2 emissions from AEP generating facilities from 2000 levels by 2050. AEP's total projected CO_2 emissions in 2018 are approximately 90 million metric tons, a 46% reduction from AEP's 2000 CO_2 emissions of approximately 167 million metric tons.

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, which could possibly lead to 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 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 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. Certain records must be posted to a publicly available internet site. Initial groundwater monitoring reports were posted in the first quarter of 2018, and some of AEP's existing facilities were required to begin assessment monitoring programs to determine if unacceptable groundwater impacts will trigger future remedial actions.

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. Oklahoma has received approval to operate its state program in lieu of the federal rules. In October 2018, the Federal EPA's approval of the Oklahoma program was challenged in the Federal District Court for the District of Columbia and in the U.S. Court of Appeals for the District of Columbia

Circuit. The Company is complying with the Oklahoma program, which remains in place.

The final 2015 rule has been challenged in the courts. In August 2018, the U.S. Circuit Court of Appeals for the District of Columbia Circuit issued its decision vacating and remanding certain provisions of the 2015 rule. Remaining issues were dismissed. None of the parties filed a motion for rehearing. The provisions addressed by the Court's decision, including changes to the provisions for unlined impoundments and legacy sites, will be the subject of further rulemaking consistent with the Court's decision.

In September 2017, the Federal EPA granted industry petitions to reconsider the CCR rule. In March 2018, the Federal EPA issued a proposed rule to modify certain provisions of the solid waste management standards and provide additional flexibility to facilities regulated under approved state programs. A final rule was signed in July 2018 that modifies certain compliance deadlines and other requirements in the rule. Additional changes to the minimum performance standards that were contained in the March proposed rule, and changes to respond to the decision of the U.S. Court of Appeals for the District of Columbia Circuit will be addressed in future rulemakings. Management supports the adoption of more flexible compliance alternatives subject to the Federal EPA or state oversight.

Other utilities and industrial sources have been engaged in litigation with environmental advocacy groups who claim that releases of contaminants from wells, CCR units, pipelines and other facilities to ground waters that have a hydrologic connection to a surface water body represents an "unpermitted discharge" under the Clean Water Act. The Federal EPA has opened a rulemaking docket to solicit information to determine whether it should provide additional clarification of the scope of Clean Water Act permitting requirements for discharges to ground water. Management is unable to predict the outcome of these cases or the Federal EPA's rulemaking, which could impose significant additional costs on AEP's facilities.

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 and conduct any required remedial actions. Management recorded a $95 million increase in asset retirement obligations in 2015 based on the closure and post-closure care requirements in the final rule. This estimate does not include costs of groundwater remediation, if required. 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. Compliance timeframes are established by the permit agency through each facility's National Pollutant Discharge Elimination System permit as those permits are renewed, and have been incorporated into permits at several AEP facilities. Petitions for review were filed by industry and environmental groups in the U.S. Court of Appeals for the Second Circuit. The court denied the petitions and upheld the final rule. AEP's facilities are reviewing these requirements as their waste water discharge permits are renewed, and making appropriate adjustments to their intake structures.

In November 2015, the Federal EPA issued a final rule revising effluent limitation guidelines for electricity generating facilities. The rule establishes limits on FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater to be imposed as soon as possible after November 2018 and no later than December 2023. These 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. 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, but has been challenged in the courts. 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. Management is actively participating in the reconsideration proceedings.

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 final rule was challenged in both courts of appeal and district courts. In January 2018, the U.S. Supreme Court ruled that challenges to the definition of “waters of the United States” must be filed in federal district courts. Challenges to the rule will proceed.

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. A supplemental proposal was signed by the Administrator in June 2018 to provide further clarification of the impact of and support for repeal of the 2015 rule. The Federal EPA and U.S. Army Corps of Engineers also finalized a new rule to extend the applicability date of the 2015 rule to 2020. Challenges to the applicability date rule were filed by third parties in several federal district courts. In August 2018, the Federal District Court for the District of South Carolina vacated the postponement of the applicability date, allowing the 2015 rule to go into effect in 26 states. Management will participate in further rulemaking activities.

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 AEP Texas and OPCo.
- OPCo purchases energy and capacity at auction to serve SSO customers and provides transmission and distribution services for all connected load.

AEP Transmission Holdco

- Development, construction and operation of transmission facilities through investments in 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 are 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 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,	
	2018	2017	2018	2017
	(in millions)			
Vertically Integrated Utilities	$344.2	$286.3	$852.2	$626.6
Transmission and Distribution Utilities	145.2	144.0	384.6	374.3
AEP Transmission Holdco	73.3	75.5	278.4	275.7
Generation & Marketing	5.3	33.7	62.3	246.3
Corporate and Other	9.6	5.2	(17.1)	(11.0)
Earnings Attributable to AEP Common Shareholders	$577.6	$544.7	$1,560.4	$1,511.9

AEP CONSOLIDATED

Third Quarter of 2018 Compared to Third Quarter of 2017

Earnings Attributable to AEP Common Shareholders increased from $545 million in 2017 to $578 million in 2018 primarily due to:

- An increase in weather-related usage.
- Favorable rate proceedings in AEP’s various jurisdictions.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

Earnings Attributable to AEP Common Shareholders increased from $1,512 million in 2017 to $1,560 million in 2018 primarily due to:

- An increase in weather-related usage.
- Favorable rate proceedings in AEP’s various jurisdictions.

These increases were partially offset by:

- A decrease in earnings in the Generation & Marketing segment primarily due to the 2017 gain resulting from the sale of certain merchant generation assets.

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

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended September 30, 2018	2017	Nine Months Ended September 30, 2018	2017
	(in millions)			
Revenues	$2,636.7	$2,482.2	$7,393.7	$6,893.1
Fuel and Purchased Electricity	1,034.6	868.6	2,700.4	2,368.9
Gross Margin	1,602.1	1,613.6	4,693.3	4,524.2
Other Operation and Maintenance	753.7	665.0	2,197.5	2,042.2
Depreciation and Amortization	340.1	288.8	966.1	845.1
Taxes Other Than Income Taxes	108.8	105.7	326.4	306.2
Operating Income	399.5	554.1	1,203.3	1,330.7
Interest and Investment Income	3.3	1.3	8.3	5.4
Carrying Costs Income	0.8	2.1	5.9	11.3
Allowance for Equity Funds Used During Construction	9.3	7.5	24.0	20.0
Non-Service Cost Components of Net Periodic Benefit Cost	18.0	5.9	53.7	17.7
Interest Expense	(149.2)	(134.9)	(428.0)	(406.5)
Income Before Income Tax Expense (Credit) and Equity Earnings (Loss)	281.7	436.0	867.2	978.6
Income Tax Expense (Credit)	(63.1)	139.1	12.9	334.9
Equity Earnings (Loss) of Unconsolidated Subsidiaries	0.8	0.4	2.0	(4.5)
Net Income	345.6	297.3	856.3	639.2
Net Income Attributable to Noncontrolling Interests	1.4	11.0	4.1	12.6
Earnings Attributable to AEP Common Shareholders	$344.2	$286.3	$852.2	$626.6

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended September 30, 2018	2017	Nine Months Ended September 30, 2018	2017
	(in millions of KWhs)			
Retail:				
Residential	8,988	8,488	26,105	23,226
Commercial	6,799	6,701	18,988	18,386
Industrial	9,032	8,839	26,471	25,792
Miscellaneous	620	603	1,759	1,701
Total Retail	25,439	24,631	73,323	69,105
Wholesale (a)	6,432	6,837	17,156	19,262
Total KWhs	31,871	31,468	90,479	88,367

(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,	
	2018	2017	2018	2017
	(in degree days)			
Eastern Region				
Actual – Heating (a)	—	—	1,844	1,266
Normal – Heating (b)	5	4	1,745	1,757
Actual – Cooling (c)	878	698	1,364	1,034
Normal – Cooling (b)	730	731	1,063	1,060
Western Region				
Actual – Heating (a)	—	—	974	539
Normal – Heating (b)	1	1	908	926
Actual – Cooling (c)	1,443	1,281	2,380	2,000
Normal – Cooling (b)	1,402	1,404	2,121	2,124

(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 2018 Compared to Third Quarter of 2017
Reconciliation of Third Quarter of 2017 to Third Quarter of 2018
Earnings Attributable to AEP Common Shareholders from Vertically
Integrated Utilities
(in millions)

Third Quarter of 2017	$286.3
Changes in Gross Margin:	
Retail Margins	4.8
Off-system Sales	(3.8)
Transmission Revenues	(6.5)
Other Revenues	(6.0)
Total Change in Gross Margin	(11.5)
Changes in Expenses and Other:	
Other Operation and Maintenance	(88.7)
Depreciation and Amortization	(51.3)
Taxes Other Than Income Taxes	(3.1)
Interest and Investment Income	2.0
Carrying Costs Income	(1.3)
Allowance for Equity Funds Used During Construction	1.8
Non-Service Cost Components of Net Periodic Pension Cost	12.1
Interest Expense	(14.3)
Total Change in Expenses and Other	(142.8)
Income Tax Expense (Credit)	202.2
Equity Earnings (Loss) of Unconsolidated Subsidiaries	0.4
Net Income Attributable to Noncontrolling Interest	9.6
Third Quarter of 2018	$344.2

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 increased $5 million primarily due to the following:
- The effect of rate proceedings in AEP’s service territories which included:
- A $47 million increase from rate proceedings for I&M, inclusive of a $22 million decrease due to the impact of Tax Reform in the Indiana jurisdiction.
- A $20 million increase for PSO due to new rates implemented in March 2018, inclusive of a $9 million decrease due to the change in the corporate federal tax rate.
- An $18 million increase for SWEPCo primarily due to rider and base rate revenue increases in Texas and Louisiana.

For the rate increases described above, $17 million related to riders/trackers, which had corresponding increases in expense items below.

- A $61 million increase in weather-related usage across all regions.

These increases were partially offset by:

- A $91 million reduction at APCo and WPCo in deferred fuel under-recovery related to the West Virginia Tax Reform settlement. This decrease was offset in Income Tax Expense (Credit) below.
-

A $13 million decrease due to lower weather-normalized wholesale margins, primarily due to SWEPCo and I&M wholesale customer load loss from contracts that expired at the end of 2017.

- A $12 million decrease in weather-normalized retail margins primarily in the industrial and commercial classes.
- An $11 million increase at APCo in deferred fuel related to recoverable PJM expenses that were offset below.

- A $10 million increase at APCo in non-recoverable fuel expense related to Virginia legislation.
- A $4 million decrease at PSO related to the System Reliability Rider (SRR) that ended in August 2017. This decrease was partially offset by a corresponding decrease recognized in other expense items below.
- Margins from Off-system Sales decreased $4 million primarily due to mid-year changes in the OSS sharing mechanism at I&M.
- Transmission Revenues decreased $7 million primarily due to the following:
- A $16 million decrease due to current year provisions for rate refunds.

These decreases were partially offset by:

- A $6 million increase primarily due to an increase in transmission investments in SPP.
- A $4 million increase primarily due to an increase in transmission investments in PJM.
- Other Revenues decreased $6 million primarily due to reduced rates for KPCo Demand Side Management programs beginning in 2018. This decrease was partially offset in Other Operation and Maintenance expenses below.

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

- Other Operation and Maintenance expenses increased $89 million primarily due to the following:
- A $40 million increase in expenses at APCo and WPCo due to the extinguishment of regulatory asset balances as agreed to within the West Virginia Tax Reform settlement. This increase was partially offset in Retail Margins above and Income Tax Expense (Credit) below.
- A $25 million increase in employee-related expenses.
- A $10 million increase in vegetation management expenses primarily in the east region.
- A $7 million increase in plant outage and maintenance expenses primarily for APCo and KPCo.
- A $4 million increase in customer-related expenses.
- A $3 million increase in SPP transmission services.
- A $3 million increase due to the Wind Catcher Project for SWEPCo and PSO.

This increase was partially offset by:

- A $23 million decrease in PJM transmission services.
- Depreciation and Amortization expenses increased $51 million primarily due to a higher depreciable base and increased depreciation rates approved at I&M, PSO and SWEPCo.
- Non-Service Cost Components of Net Periodic Benefit Cost decreased $12 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- Interest Expense increased $14 million primarily due to the following:
- A $7 million increase at I&M primarily due to increased long-term debt balances.
- A $3 million increase at PSO due to the 2017 deferral of the debt component of carrying charges on environmental control costs for projects at Northeastern Plant, Unit 3 and Comanche Plant.
- A $3 million increase in other interest expense at APCo due to the West Virginia Tax Reform settlement.
- Income Tax Expense (Credit) decreased $202 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT, other book/tax differences which are accounted for on a flow-through basis and a decrease in pretax book income.
- Net Income Attributable to Noncontrolling Interest decreased $10 million primarily due to income tax benefits attributable to SWEPCo's noncontrolling interest in Sabine. This decrease was offset by an increase in Income Tax Expense (Credit) above.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

Reconciliation of Nine Months Ended September 30, 2017 to Nine
Months Ended September 30, 2018
Earnings Attributable to AEP Common Shareholders from Vertically
Integrated Utilities
(in millions)

Nine Months Ended September 30, 2017	$626.6
Changes in Gross Margin:	
Retail Margins	167.3
Off-system Sales	(6.9)
Transmission Revenues	24.8
Other Revenues	(16.1)
Total Change in Gross Margin	169.1
Changes in Expenses and Other:	
Other Operation and Maintenance	(155.3)
Depreciation and Amortization	(121.0)
Taxes Other Than Income Taxes	(20.2)
Interest and Investment Income	2.9
Carrying Costs Income	(5.4)
Allowance for Equity Funds Used During Construction	4.0
Non-Service Cost Components of Net Periodic Pension Cost	36.0
Interest Expense	(21.5)
Total Change in Expenses and Other	(280.5)
Income Tax Expense (Credit)	322.0
Equity Earnings (Loss) of Unconsolidated Subsidiaries	6.5
Net Income Attributable to Noncontrolling Interest	8.5
Nine Months Ended September 30, 2018	$852.2

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

- Retail Margins increased $167 million primarily due to the following:
- A $240 million increase in weather-related usage across all regions primarily in the residential and commercial classes.
- The effect of rate proceedings in AEP’s service territories which included:
- An $89 million increase from rate proceedings for I&M, inclusive of a $26 million decrease due to the impact of Tax Reform in the Indiana jurisdiction.
- A $57 million increase for SWEPCo due to rider and base rate revenue increases in Texas, Louisiana and Arkansas.
- A $37 million increase for PSO due to new rates implemented in March 2018, inclusive of a $19 million decrease due to the change in the corporate federal tax rate.

For the rate increases described above, $4 million related to riders/trackers, which had corresponding increases in expense items below.

- A $32 million increase for I&M in FERC generation wholesale municipal and cooperative revenues primarily due to changes to the annual formula rate.

- A $16 million increase in weather-normalized retail margins primarily in the residential class.

These increases were partially offset by:

- A $111 million decrease due to customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense (Credit) below.
- A $91 million reduction at APCo and WPCo in deferred fuel under-recovery related to the West Virginia Tax Reform settlements. This decrease was offset in Income Tax Expense (Credit) below.

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- A $39 million decrease due to lower weather-normalized wholesale margins, primarily due to SWEPCo and I&M wholesale customer load loss from contracts that expired at the end of 2017.
- A $28 million increase at APCo in deferred fuel related to recoverable PJM expenses that were offset below.
- A $16 million decrease primarily due to increased fuel and other variable production costs not recovered through fuel clauses or other trackers.
- A $16 million decrease at PSO related to the SRR that ended in August 2017. This decrease was partially offset by a corresponding decrease recognized in other expense items below.
- A $10 million increase at APCo in non-recoverable fuel expense related to Virginia legislation.
- Margins from Off-system Sales decreased $7 million primarily due to mid-year changes in the OSS sharing mechanism at I&M.
- Transmission Revenues increased $25 million primarily due to the following:
- A $23 million increase due to the annual formula rate true-up and decreased RTO provisions at I&M.
- A $19 million increase primarily due to an increase in transmission investments in SPP.

These increases were partially offset by:

- A $16 million decrease due to current year provisions for rate refunds.
- Other Revenues decreased $16 million primarily due to reduced rates for KPCo Demand Side Management programs beginning in 2018. This decrease was partially offset in Other Operation and Maintenance expenses below.

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

- Other Operation and Maintenance expenses increased $155 million primarily due to the following:
- A $40 million increase in expenses at APCo and WPCo due to the extinguishment of regulatory asset balances as agreed to within the West Virginia Tax Reform settlement. This increase was partially offset in Retail Margins above and Income Tax Expense (Credit) below.
- A $39 million increase in SPP transmission services.
- A $35 million increase due to the Wind Catcher Project for SWEPCo and PSO.
- A $25 million increase in employee-related expenses.
- A $19 million increase in plant outage and maintenance expenses primarily for KPCo and I&M.
- A $13 million increase in vegetation management.
- A $9 million increase due to an increase in estimated expense for claims related to asbestos exposure.
- A $7 million increase in storms primarily for APCo.
- A $6 million increase in customer-related expenses.
- A $5 million increase in factoring expense.

These increases were partially offset by:

- A $55 million decrease in PJM transmission expenses primarily due to the annual formula rate true-up.
- Depreciation and Amortization expenses increased $121 million primarily due to a higher depreciable base and increased depreciation rates approved at I&M, PSO and SWEPCo.
- Taxes Other Than Income Taxes increased $20 million primarily due to:
- An $8 million increase in property taxes driven by an increase in utility plant.
- An $8 million increase in state and local taxes due to higher reported taxable KWh and taxable revenues and a prior period refund.
- Carrying Costs Income decreased $5 million primarily due to a decrease in carrying charges for certain riders at I&M.
- Allowance for Equity Funds Used During Construction increased $4 million primarily due to an increase in construction activity at APCo and SWEPCo.
- Non-Service Cost Components of Net Periodic Benefit Cost decreased $36 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation

of ASU 2017-07.

- Interest Expense increased $22 million primarily due to the following:
  - A $13 million increase due to increased long-term debt balances at I&M.
  - A $7 million increase at PSO primarily due to the 2017 deferral of the debt component of carrying charges on environmental control costs for projects at Northeastern Plant, Unit 3 and Comanche Plant.
  - A $3 million increase at SWEPCo primarily due to other interest expense accruals for refunds and true-ups in 2018 and interest expense credits in 2017 on Welsh Plant and Flint Creek Plant environmental project deferrals.
- Income Tax Expense (Credit) decreased $322 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT, other book/tax differences which are accounted for on a flow-through basis and a decrease in pretax book income.
- Equity Earnings (Loss) of Unconsolidated Subsidiaries increased $7 million primarily due to a prior period income tax adjustment recognized in 2017.
- Net Income Attributable to Noncontrolling Interest decreased $9 million primarily due to income tax benefits attributable to SWEPCo's noncontrolling interest in Sabine. This decrease was offset by an increase in Income Tax Expense (Credit) above.

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Three Months Ended September 30, 2018	2017	Nine Months Ended September 30, 2018	2017
	(in millions)			
Revenues	$1,211.5	$1,173.3	$3,510.9	$3,313.2
Purchased Electricity	218.7	215.7	660.0	626.0
Amortization of Generation Deferrals	56.9	58.7	171.9	172.9
Gross Margin	935.9	898.9	2,679.0	2,514.3
Other Operation and Maintenance	420.4	305.4	1,152.1	889.2
Depreciation and Amortization	201.4	182.3	558.4	502.4
Taxes Other Than Income Taxes	143.2	133.6	413.2	387.1
Operating Income	170.9	277.6	555.3	735.6
Interest and Investment Income	1.3	1.2	2.6	5.6
Carrying Costs Income	0.2	0.5	1.5	3.0
Allowance for Equity Funds Used During Construction	7.8	0.9	23.0	6.3
Non-Service Cost Components of Net Periodic Benefit Cost	8.3	2.2	24.6	6.7
Interest Expense	(63.5)	(61.0)	(185.6)	(182.5)
Income Before Income Tax Expense (Credit)	125.0	221.4	421.4	574.7
Income Tax Expense (Credit)	(20.2)	77.4	36.8	200.4
Net Income	145.2	144.0	384.6	374.3
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$145.2	$144.0	$384.6	$374.3

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended September 30, 2018	2017	Nine Months Ended September 30, 2018	2017
	(in millions of KWhs)			
Retail:				
Residential	7,948	7,511	21,154	19,361
Commercial	7,165	6,941	19,634	19,184
Industrial	5,720	5,575	17,259	16,992
Miscellaneous	186	185	514	516
Total Retail (a)	21,019	20,212	58,561	56,053
Wholesale (b)	634	585	1,835	1,749
Total KWhs	21,653	20,797	60,396	57,802

(a) Represents energy delivered to distribution customers.
(b) Primarily OPCo’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,	
	2018	2017	2018	2017
	(in degree days)			
Eastern Region				
Actual – Heating (a)	—	—	2,158	1,500
Normal – Heating (b)	6	6	2,076	2,091
Actual – Cooling (c)	864	642	1,322	957
Normal – Cooling (b)	670	670	964	960
Western Region				
Actual – Heating (a)	—	—	234	103
Normal – Heating (b)	—	—	194	199
Actual – Cooling (d)	1,424	1,393	2,612	2,640
Normal – Cooling (b)	1,367	1,364	2,413	2,396

(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 2018 Compared to Third Quarter of 2017
Reconciliation of Third Quarter of 2017 to Third Quarter of 2018
Earnings Attributable to AEP Common Shareholders from
Transmission and Distribution Utilities
(in millions)

Third Quarter of 2017	$144.0
Changes in Gross Margin:	
Retail Margins	21.2
Off-system Sales	16.0
Transmission Revenues	(0.8)
Other Revenues	0.6
Total Change in Gross Margin	37.0
Changes in Expenses and Other:	
Other Operation and Maintenance	(115.0)
Depreciation and Amortization	(19.1)
Taxes Other Than Income Taxes	(9.6)
Interest and Investment Income	0.1
Carrying Costs Income	(0.3)
Allowance for Equity Funds Used During Construction	6.9
Non-Service Cost Components of Net Periodic Benefit Cost	6.1
Interest Expense	(2.5)
Total Change in Expenses and Other	(133.4)
Income Tax Expense (Credit)	97.6
Third Quarter of 2018	$145.2

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

- Retail Margins increased $21 million primarily due to the following:
  - A $46 million net increase in Ohio Basic Transmission Cost Rider revenues and recoverable PJM expenses. This increase was partially offset by an increase in Other Operation and Maintenance below.
  - A $21 million increase in Ohio revenues associated with the Universal Service Fund (USF). This increase was offset by a corresponding increase in Other Operation and Maintenance expenses below.
  - A $7 million increase in revenues associated with smart grid riders in Ohio. This increase was partially offset by an increase in various expenses below.
  - A $4 million increase in Ohio rider revenues associated with the DIR. This increase was partially offset in various expenses below.
  - A $3 million increase in rider revenues recovering state excise taxes due to an increase in metered KWh in Ohio. This increase was offset by a corresponding increase in Taxes Other Than Income Taxes below.
  - A $3 million increase in Texas revenues associated with the Distribution Cost Recovery Factor revenue rider.
  - A $2 million increase in Texas revenues associated with the Transmission Cost Recovery Factor revenue rider. This increase was partially offset by an increase in Other Operation and Maintenance expenses below.

  These increases were partially offset by:
  -

- A $46 million decrease due to adjustments to the distribution decoupling under-recovery balance as a result of the 2018 Ohio Tax Reform settlement. This decrease was offset in Income Tax Expense (Credit) below.
- A $12 million decrease in Ohio due to the recovery of lower current year losses from a power contract with OVEC. This decrease was offset by a corresponding increase in Margins from Off-system Sales below.
- An $11 million decrease in weather-normalized margins.
- Margins from Off-system Sales increased $16 million primarily due to lower current year losses from a power contract with OVEC in Ohio which was offset in Retail Margins above as a result of the OVEC PPA rider beginning in January 2017.

- Transmission Revenues decreased $1 million primarily due to the following:
- A $6 million decrease due to lower rates in order to pass the benefits of Tax Reform on to customers in Texas. This decrease was offset in Income Tax Expense (Credit) below.

This decrease was offset by:

- A $6 million increase due to recovery of increased transmission investment in ERCOT.

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

- Other Operation and Maintenance expenses increased $115 million primarily due to the following:
- A $51 million increase in recoverable transmission expenses that were fully recovered in rate recovery riders/trackers within Gross Margins above.
- A $21 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in Retail Margins above.
- A $10 million increase in employee-related expenses.
- A $4 million increase in customer-related expenses.
- Depreciation and Amortization expenses increased $19 million primarily due to the following:
- A $10 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
- A $4 million increase in recoverable smart grid depreciation expenses in Ohio. This increase was offset in Retail Margins above.
- A $2 million increase in amortization due to capitalized software.
- Taxes Other Than Income Taxes increased $10 million primarily due to the following:
- A $5 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.
- A $4 million increase in rider revenues recovering state excise taxes due to an increase in metered KWhs. This increase was offset in Retail Margins above.
- Allowance for Equity Funds Used During Construction increased $7 million primarily due to increased transmission projects in Texas.
- Non-Service Cost Components of Net Periodic Benefit Cost decreased $6 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- Income Tax Expense (Credit) decreased $98 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

Reconciliation of Nine Months Ended September 30, 2017 to Nine Months Ended September 30, 2018
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Nine Months Ended September 30, 2017	$374.3
Changes in Gross Margin:	
Retail Margins	140.4
Off-system Sales	32.6
Transmission Revenues	(7.6)
Other Revenues	(0.7)
Total Change in Gross Margin	164.7
Changes in Expenses and Other:	
Other Operation and Maintenance	(262.9)
Depreciation and Amortization	(56.0)
Taxes Other Than Income Taxes	(26.1)
Interest and Investment Income	(3.0)
Carrying Costs Income	(1.5)
Allowance for Equity Funds Used During Construction	16.7
Non-Service Cost Components of Net Periodic Benefit Cost	17.9
Interest Expense	(3.1)
Total Change in Expenses and Other	(318.0)
Income Tax Expense (Credit)	163.6
Nine Months Ended September 30, 2018	$384.6

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

- Retail Margins increased $140 million primarily due to the following:
  - A $155 million net increase in Ohio Basic Transmission Cost Rider revenues and recoverable PJM expenses. This increase was partially offset by an increase in Other Operation and Maintenance expenses below.
  - A $61 million increase in Ohio revenues associated with the USF. This increase was offset by a corresponding increase in Other Operation and Maintenance expenses below.
  - An $18 million increase in Ohio rider revenues associated with the DIR. This increase was partially offset in various expenses below.
  - A $16 million increase in Texas revenues associated with the Distribution Cost Recovery Factor revenue rider.
  - A $13 million increase in Texas revenues associated with the Transmission Cost Recovery Factor revenue rider. This increase was partially offset by an increase in Other Operation and Maintenance expenses below.
  - A $13 million increase in Texas weather-related usage primarily driven by a 127% increase in heating degree days partially offset by a 1% decrease in cooling degree days.

  These increases were partially offset by:
  - A $46 million decrease due to adjustments to the distribution decoupling under-recovery balance as a result of the 2018 Ohio Tax Reform settlement. This decrease was offset in Income Tax Expense (Credit) below.

- A $42 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense (Credit) below.
- A $30 million decrease in Ohio due to the recovery of lower current year losses from a power contract with OVEC. This decrease was offset by a corresponding increase in Margins from Off-system Sales below.

- Margins from Off-system Sales increased $33 million primarily due to lower current year losses from a power contract with OVEC in Ohio which was offset in Retail Margins above as a result of the OVEC PPA rider beginning in January 2017.
- Transmission Revenues decreased $8 million primarily due to the following:
- A $20 million decrease due to the 2018 provisions for customer refunds due to Tax Reform. This decrease was offset in Income Tax Expense (Credit) below.
- A $6 million decrease due to lower rates in order to pass the benefits of Tax Reform on to customers in Texas. This decrease was offset in Income Tax Expense (Credit) below.

These decreases were partially offset by:

- A $19 million increase due to recovery of increased transmission investment in ERCOT.

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

- Other Operation and Maintenance expenses increased $263 million primarily due to the following:
- A $195 million increase in recoverable transmission expenses that were fully recovered in rate recovery riders/trackers within Gross Margins above.
- A $61 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in Retail Margins above.
- A $7 million increase in distribution expenses.
- A $7 million increase in employee-related expenses.

These increases were partially offset by:

- A $55 million decrease in Ohio PJM expenses primarily related to the annual formula rate true-up that will be refunded in future periods.
- Depreciation and Amortization expenses increased $56 million primarily due to the following:
- A $28 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
- A $13 million increase in recoverable DIR depreciation expense in Ohio. This increase was offset in Retail Margins above.
- A $6 million increase in amortization due to capitalized software.
- A $5 million increase due to securitization amortizations related to Texas securitized transition funding. This increase was offset in Other Revenues and in Interest Expense.
- Taxes Other Than Income Taxes increased $26 million primarily due to the following:
- A $14 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.
- An $11 million increase in rider revenues recovering state excise taxes due to an increase in metered KWhs. This increase was offset in Retail Margins above.
- Allowance for Equity Funds Used During Construction increased $17 million primarily due to increased transmission projects in Texas.
- Non-Service Cost Components of Net Periodic Benefit Cost decreased $18 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- Income Tax Expense (Credit) decreased $164 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

AEP TRANSMISSION HOLDCO

AEP Transmission Holdco	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
	(in millions)			
Transmission Revenues	$187.2	$178.5	$605.2	$581.9
Other Operation and Maintenance	30.9	23.2	76.2	54.7
Depreciation and Amortization	34.4	26.1	100.0	74.7
Taxes Other Than Income Taxes	36.3	28.6	106.5	85.0
Operating Income	85.6	100.6	322.5	367.5
Interest and Investment Income	0.4	0.1	1.1	0.4
Allowance for Equity Funds Used During Construction	13.8	11.6	45.4	35.9
Non-Service Cost Components of Net Periodic Benefit Cost	0.7	0.1	2.1	0.2
Interest Expense	(24.2)	(17.9)	(66.8)	(52.3)
Income Before Income Tax Expense and Equity Earnings	76.3	94.5	304.3	351.7
Income Tax Expense	19.2	38.6	75.0	142.1
Equity Earnings of Unconsolidated Subsidiaries	17.1	20.6	51.6	68.7
Net Income	74.2	76.5	280.9	278.3
Net Income Attributable to Noncontrolling Interests	0.9	1.0	2.5	2.6
Earnings Attributable to AEP Common Shareholders	$73.3	$75.5	$278.4	$275.7

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	September 30, 2018	September 30, 2017
	(in millions)	
Plant in Service	$6,307.3	$5,001.4
Construction Work in Progress	1,823.0	1,392.8
Accumulated Depreciation and Amortization	244.3	156.6
Total Transmission Property, Net	$7,886.0	$6,237.6

Third Quarter of 2018 Compared to Third Quarter of 2017

Reconciliation of Third Quarter of 2017 to Third Quarter of 2018
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Third Quarter of 2017	$75.5
Changes in Transmission Revenues:	
Transmission Revenues	8.7
Total Change in Transmission Revenues	8.7
Changes in Expenses and Other:	
Other Operation and Maintenance	(7.7)
Depreciation and Amortization	(8.3)
Taxes Other Than Income Taxes	(7.7)
Interest and Investment Income	0.3
Allowance for Equity Funds Used During Construction	2.2
Non-Service Cost Components of Net Periodic Pension Cost	0.6
Interest Expense	(6.3)
Total Change in Expenses and Other	(26.9)
Income Tax Expense	19.4
Equity Earnings of Unconsolidated Subsidiaries	(3.5)
Net Income Attributable to Noncontrolling Interests	0.1
Third Quarter of 2018	$73.3

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

- Transmission Revenues increased $9 million primarily due to an increase in the formula rate revenue requirement primarily driven by continued investment in transmission assets. This increase includes the impact of the reduction in revenue related to Tax Reform, which was offset by a decrease in Income Tax Expense below.

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

- Other Operation and Maintenance expenses increased $8 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $8 million primarily due to a higher depreciable base.
- Taxes Other Than Income Taxes increased $8 million primarily due to higher property taxes as a result of increased transmission investment.
- Interest Expense increased $6 million primarily due to higher long-term debt balances.
- Income Tax Expense decreased $19 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.
- Equity Earnings of Unconsolidated Subsidiaries decreased $4 million due to lower pretax equity earnings at ETT primarily due to decreased revenues driven by Tax Reform.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

Reconciliation of Nine Months Ended September 30, 2017 to Nine Months Ended September 30, 2018
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Nine Months Ended September 30, 2017	$275.7
Changes in Transmission Revenues:	
Transmission Revenues	23.3
Total Change in Transmission Revenues	23.3
Changes in Expenses and Other:	
Other Operation and Maintenance	(21.5)
Depreciation and Amortization	(25.3)
Taxes Other Than Income Taxes	(21.5)
Interest and Investment Income	0.7
Allowance for Equity Funds Used During Construction	9.5
Non-Service Cost Components of Net Periodic Pension Cost	1.9
Interest Expense	(14.5)
Total Change in Expenses and Other	(70.7)
Income Tax Expense	67.1
Equity Earnings of Unconsolidated Subsidiaries	(17.1)
Net Income Attributable to Noncontrolling Interests	0.1
Nine Months Ended September 30, 2018	$278.4

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

- Transmission Revenues increased $23 million primarily due to the following:
  - An $87 million increase in revenues due to an increase in the formula rate revenue requirement primarily driven by continued investment in transmission assets. This increase includes the impact of the reduction in revenue related to Tax Reform, which was offset by a decrease in Income Tax Expense below.

  This increase was partially offset by:
  - A $64 million decrease in revenues due to a lower annual formula rate true-up in 2018 driven by implementing forward looking formula rates in 2017.

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

- Other Operation and Maintenance expenses increased $22 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $25 million primarily due to a higher depreciable base.
- Taxes Other Than Income Taxes increased $22 million primarily due to higher property taxes as a result of increased transmission investment.
- Allowance for Equity Funds Used During Construction increased $10 million primarily due to increased transmission investment resulting in a higher CWIP balance.
- Interest Expense increased $15 million primarily due to the following:
  - A $19 million increase primarily due to higher long-term debt balances.

This increase was partially offset by:

- A $4 million decrease due to higher AFUDC borrowed funds resulting from a higher CWIP balance.

- Income Tax Expense decreased $67 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.
- Equity Earnings of Unconsolidated Subsidiaries decreased $17 million primarily due to lower pretax equity earnings at ETT due to decreased revenues driven by Tax Reform and an ETT rate reduction implemented in March 2017.

GENERATION & MARKETING

Generation & Marketing	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
	(in millions)			
Revenues	$521.6	$465.5	$1,487.4	$1,467.5
Fuel, Purchased Electricity and Other	405.0	354.6	1,167.8	1,062.7
Gross Margin	116.6	110.9	319.6	404.8
Other Operation and Maintenance	68.2	58.7	192.6	218.1
Asset Impairments and Other Related Charges	35.0	(2.5)	35.0	10.6
Gain on Sale of Merchant Generation Assets	—	—	—	(226.4)
Depreciation and Amortization	12.0	6.2	26.4	17.5
Taxes Other Than Income Taxes	3.7	3.2	10.3	8.9
Operating Income (Loss)	(2.3)	45.3	55.3	376.1
Interest and Investment Income	3.6	2.7	9.9	7.9
Non-Service Cost Components of Net Periodic Benefit Cost	3.8	2.2	11.5	6.7
Interest Expense	(3.8)	(4.0)	(11.7)	(14.7)
Income Before Income Tax Expense (Credit) and Equity Earnings	1.3	46.2	65.0	376.0
Income Tax Expense (Credit)	(3.6)	12.5	3.7	129.7
Equity Earnings of Unconsolidated Subsidiaries	0.2	—	0.5	—
Net Income	5.1	33.7	61.8	246.3
Net Loss Attributable to Noncontrolling Interests	(0.2)	—	(0.5)	—
Earnings Attributable to AEP Common Shareholders	$5.3	$33.7	$62.3	$246.3

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
	(in millions of MWhs)			
Fuel Type:				
Coal	4	2	10	10
Natural Gas	—	—	—	2
Wind	—	—	1	—
Total MWhs	4	2	11	12

Third Quarter of 2018 Compared to Third Quarter of 2017
Reconciliation of Third Quarter of 2017 to Third Quarter of 2018
Earnings Attributable to AEP Common Shareholders from
Generation & Marketing
(in millions)

Third Quarter of 2017	$33.7
Changes in Gross Margin:	
Generation	(7.5)
Retail, Trading and Marketing	6.7
Other Revenues	6.5
Total Change in Gross Margin	5.7
Changes in Expenses and Other:	
Other Operation and Maintenance	(9.5)
Asset Impairments and Other Related Charges	(37.5)
Depreciation and Amortization	(5.8)
Taxes Other Than Income Taxes	(0.5)
Interest and Investment Income	0.9
Non-Service Cost Components of Net Periodic Benefit Cost	1.6
Interest Expense	0.2
Total Change in Expenses and Other	(50.6)
Income Tax Expense (Credit)	16.1
Equity Earnings of Unconsolidated Subsidiaries	0.2
Net Loss Attributable to Noncontrolling Interests	0.2
Third Quarter of 2018	$5.3

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

- Generation decreased $8 million primarily due to the reduction of energy margins.
- Retail, Trading and Marketing increased $7 million due to increased energy volumes.
- Other Revenues increased $7 million primarily due to renewable projects placed in service and the repowering of Trent and Desert Sky.

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

- Other Operation and Maintenance expenses increased $10 million primarily due to the following:
  - A $17 million increase due to severance accruals related to the announced merchant generation plant retirements.

  This increase was partially offset by:
  - A $7 million decrease primarily due to the sale of certain merchant generation assets in 2017.
- Asset Impairments and Other Related Charges increased $38 million primarily due to the $35 million impairment of Racine in the third quarter of 2018.
- Depreciation and Amortization increased $6 million due to a higher depreciable base from increased investments in wind farms and renewable energy sources.

- Income Tax Expense (Credit) decreased $16 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform and a decrease in pretax book income.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

Reconciliation of Nine Months Ended September 30, 2017 to Nine Months Ended September 30, 2018
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Nine Months Ended September 30, 2017	$246.3
Changes in Gross Margin:	
Generation	(74.6)
Retail, Trading and Marketing	(20.1)
Other Revenues	9.5
Total Change in Gross Margin	(85.2)
Changes in Expenses and Other:	
Other Operation and Maintenance	25.5
Asset Impairments and Other Related Charges	(24.4)
Gain on Sale of Merchant Generation Assets	(226.4)
Depreciation and Amortization	(8.9)
Taxes Other Than Income Taxes	(1.4)
Interest and Investment Income	2.0
Non-Service Cost Components of Net Periodic Benefit Cost	4.8
Interest Expense	3.0
Total Change in Expenses and Other	(225.8)
Income Tax Expense (Credit)	126.0
Equity Earnings of Unconsolidated Subsidiaries	0.5
Net Loss Attributable to Noncontrolling Interests	0.5
Nine Months Ended September 30, 2018	$62.3

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 $75 million primarily due to the reduction of revenues associated with the sale of certain merchant generation assets in 2017 combined with reduced energy margins in 2018.
- Retail, Trading and Marketing decreased $20 million primarily due to lower margins in 2018 combined with the impact of favorable wholesale trading and marketing performance in 2017.
- Other Revenues increased $10 million primarily due to renewable projects placed in service and the repowering of Trent and Desert Sky.

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

- Other Operation and Maintenance expenses decreased $26 million primarily due the following:
  - A $43 million decrease primarily due to the sale of certain merchant generation assets in 2017.

  This decrease was partially offset by:
  - A $17 million increase due to severance accruals related to the announced merchant generation plant retirements.

- Asset Impairments and Other Related Charges increased $24 million due to the $35 million impairment of Racine in the third quarter of 2018 compared to the $11 million impairment of other merchant generation assets in 2017.
- Gain on Sale of Merchant Generation Assets decreased $226 million due to the sale of certain merchant generation assets in 2017.
- Depreciation and Amortization increased $9 million due to a higher depreciable base from increased investments in wind farms and renewable energy sources.

- Non-Service Cost Components of Net Periodic Benefit Cost decreased $5 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- Income Tax Expense (Credit) decreased $126 million primarily due to a decrease in pretax book income driven by the gain on the sale of certain merchant generation assets in 2017 and the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform.

CORPORATE AND OTHER

Third Quarter of 2018 Compared to Third Quarter of 2017

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from $5 million in 2017 to $10 million in 2018 primarily due to a $25 million decrease in general corporate expenses and a $10 million decrease in federal income tax expense, partially offset by a $14 million increase in interest expense as a result of increased debt outstanding and a $12 million gain recognized on the sale of an equity investment in the third quarter of 2017.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $11 million in 2017 to a loss of $17 million in 2018 primarily due to a $42 million increase in interest expense as a result of increased debt outstanding, a $20 million impairment of an equity investment and related assets in 2018 and a $12 million gain recognized on the sale of an equity investment in the third quarter of 2017. These items were partially offset by a $45 million decrease in general corporate expenses and an $18 million decrease in income tax expense related to the enactment of the Kentucky state tax legislation in the second quarter of 2018.

AEP SYSTEM INCOME TAXES

Third Quarter of 2018 Compared to Third Quarter of 2017

Income Tax Expense decreased $345 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

Income Tax Expense decreased $704 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

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, 2018		December 31, 2017	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$22,774.0	51.7 %	$21,173.3	51.5 %
Short-term Debt	2,242.6	5.1	1,638.6	4.0
Total Debt	25,016.6	56.8	22,811.9	55.5
AEP Common Equity	19,016.8	43.1	18,287.0	44.4
Noncontrolling Interests	30.0	0.1	26.6	0.1
Total Debt and Equity Capitalization	$44,063.4	100.0%	$41,125.5	100.0%

AEP's ratio of debt-to-total capital increased from 55.5% as of December 31, 2017 to 56.8% as of September 30, 2018 primarily due to an increase in debt due to increasing construction expenditures for distribution and transmission investments.

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, 2018, AEP had a $3 billion revolving credit facility commitment to support its operations. In October 2018, the revolving credit facility was increased to $4 billion and extended until June 2022. 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, 2018, available liquidity was approximately $2.3 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$3,000.0	June 2021
Cash and Cash Equivalents	788.3	
Total Liquidity Sources	3,788.3	
Less: AEP Commercial Paper Outstanding	1,473.2	
Net Available Liquidity	$2,315.1	

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 2018 was $2.3 billion. The weighted-average interest rate for AEP’s commercial paper during 2018 was 2.25%.

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 on behalf of subsidiaries under four uncommitted facilities totaling $305 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of September 30, 2018 was $72 million with maturities ranging from October 2018 to September 2019.

Securitized Accounts Receivables

AEP's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and was amended in July 2018 to include a $125 million and a $625 million facility which expire in July 2020 and 2021, respectively.

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, 2018, this contractually-defined percentage was 55.1%. 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 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 $0.67 per share in October 2018. 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 will have any significant impact on its ability to access cash to meet the payment of dividends on its common stock. See "Dividend Restrictions" section of Note 12 for additional information.

Credit Ratings

AEP and its utility subsidiaries do 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 its 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. 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.

	Nine Months Ended September 30,	
	2018	2017
	(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$412.6	$403.5
Net Cash Flows from Operating Activities	3,932.6	3,124.2
Net Cash Flows Used for Investing Activities	(4,688.7)	(1,722.7)
Net Cash Flows from (Used for) Financing Activities	1,281.0	(1,314.2)
Net Increase in Cash, Cash Equivalents and Restricted Cash	524.9	87.3
Cash, Cash Equivalents and Restricted Cash at End of Period	$937.5	$490.8

Operating Activities

	Nine Months Ended September 30,	
	2018	2017
	(in millions)	
Net Income	$1,566.5	$1,527.1
Non-Cash Adjustments to Net Income (a)	1,728.7	2,030.6
Mark-to-Market of Risk Management Contracts	(95.4)	(56.2)
Pension Contributions to Qualified Plant Trust	—	(93.3)
Property Taxes	304.8	291.4
Deferred Fuel Over/Under Recovery, Net	210.6	81.0
Recovery of Ohio Capacity Costs, Net	52.7	65.6
Provision for Refund - Global Settlement, Net	(5.5)	(93.3)
Change in Other Noncurrent Assets	161.6	(334.6)
Change in Other Noncurrent Liabilities	141.9	205.7
Change in Certain Components of Working Capital	(133.3)	(499.8)
Net Cash Flows from Operating Activities	$3,932.6	$3,124.2

(a) Non-Cash Adjustments to Net Income includes Depreciation and Amortization, Deferred Income Taxes, Allowance for Equity Funds Used During Construction, Amortization of Nuclear Fuel, Gain on Sale of Merchant Generation Assets and Gain on Sale of Equity Investments.

Net Cash Flows from Operating Activities increased by $808 million primarily due to the following:

- A $496 million increase in cash from Change in Other Noncurrent Assets primarily due to changes in regulatory assets as a result of the impact of the FERC settlement on regulated AEP subsidiaries with rider recovery mechanisms in addition to the settlement of certain regulatory assets as a result of Ohio and West Virginia jurisdictional orders related to Tax Reform. See Note 4 - Rate Matters for additional information.
- A $367 million increase in cash from Change in Certain Components of Working Capital. This increase is primarily due to lower employee-related payments, increased provisions for refund related to Tax Reform and decreased Fuel, Material and Supplies balances, partially offset by timing of receivables and payables.

- A $130 million increase in cash from Deferred Fuel Over/Under Recovery, Net primarily due to fluctuations of fuel and purchase power costs at PSO and the reduction of ENEC balances at APCo and WPCo as a result of the West Virginia Tax Reform Order.
- A $93 million increase in cash due to a pension contribution made in the second quarter of 2017.

- An $88 million increase in cash due to Provision for Refund - Global Settlement, Net. Refunds were primarily issued in 2017.

These increases in cash were partially offset by:

- A $263 million decrease in cash from Net Income, after non-cash adjustments. See Results of Operations for additional information.

Investing Activities

	Nine Months Ended September 30, 2018	2017
	(in millions)	
Construction Expenditures	$(4,688.4)	$(3,778.2)
Acquisitions of Nuclear Fuel	(26.1)	(73.2)
Proceeds from Sale of Merchant Generation Assets	—	2,159.6
Other	25.8	(30.9)
Net Cash Flows Used for Investing Activities	$(4,688.7)	$(1,722.7)

Net Cash Flows Used for Investing Activities increased by $3 billion primarily due to the following:

- A $2.2 billion decrease in cash due to the sale of certain merchant generation assets in 2017. See Note 6 - Dispositions and Impairments for additional information.
- A $910 million decrease in cash due to increased construction expenditures, primarily due to increases in Transmission and Distribution Utilities of $653 million and AEP Transmission Holdco of $140 million.

Financing Activities

	Nine Months Ended September 30, 2018	2017
	(in millions)	
Issuance of Common Stock, Net	$62.5	$—
Issuance/Retirement of Debt, Net	2,216.5	(338.2)
Dividends Paid on Common Stock	(922.5)	(875.0)
Other	(75.5)	(101.0)
Net Cash Flows from (Used for) Financing Activities	$1,281.0	$(1,314.2)

Net Cash Flows from (Used for) Financing Activities increased by $2.6 billion primarily due to the following:

- A $1.3 billion increase in cash from short-term debt primarily due to increased borrowings of commercial paper. See Note 12 - Financing Activities for additional information.
- An $829 million increase in cash due to increased issuances of long-term debt. See Note 12 - Financing Activities for additional information.
- A $468 million increase in cash due to decreased retirements of long-term debt. See Note 12 - Financing Activities for additional information.
- A $62 million increase in cash due to increased proceeds from issuances of common stock.

These increases in cash were partially offset by:

- A $48 million decrease due to increased common stock dividend payments primarily due to increased dividends per share from 2017 to 2018.

In October 2018, I&M retired $4 million of Notes Payable related to DCC Fuel.

BUDGETED CONSTRUCTION EXPENDITURES

Management forecasts approximately $24 billion of construction expenditures for 2018 to 2021. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. Management expects to fund these construction expenditures through cash flows from operations and financing activities. Generally, the Registrant Subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. For complete information of forecasted construction expenditures, see the “Budgeted Construction Expenditures” section of “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in the 2017 Annual Report.

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, 2018	December 31, 2017
	(in millions)	
Rockport Plant, Unit 2 Future Minimum Lease Payments	$ 664.7	$ 738.4
Railcars Maximum Potential Loss from Lease Agreement	13.9	17.9

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 2017 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2017 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in the “Cash Flow” section above.

CYBER SECURITY

The electric utility industry is an identified critical infrastructure function with mandatory cyber security requirements under the authority of FERC. The North American Electric Reliability Corporation (NERC), which FERC certified as the nation’s Electric Reliability Organization, developed mandatory critical infrastructure protection cyber security reliability standards. AEP began participating in the NERC grid security and emergency response exercises, GridEx, in 2013 and continues to participate in the bi-yearly exercises. These efforts, led by NERC, test and further develop the coordination, threat sharing and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation’s electric grid. In 2014, the U.S. Department of Energy published an Energy Sector Cyber Security Framework Implementation Guide for utilities to use in adopting and implementing the National Institute of Standards and Technology framework. AEP continues to be actively engaged in the framework process. In addition to these enterprise-wide initiatives, the operations of AEP’s electric utility subsidiaries are subject to extensive and rigorous mandatory cyber security requirements that are developed and enforced by NERC to protect grid security and reliability.

Critical cyber assets, such as data centers, power plants, transmission operations centers and business networks are protected using multiple layers of cyber security and authentication. Cyber hackers have been successful in breaching a number of very secure facilities, including federal agencies, banks and retailers. As these events become known and develop, AEP continually assesses its cyber security tools and processes to determine where to strengthen its defenses.

AEP has undertaken a variety of actions to monitor and address cyber-related risks. Cyber security and the effectiveness of AEP's cyber security processes are discussed at Board and Audit Committee meetings. AEP's strategy for managing cyber-related risks is integrated within its enterprise risk management processes.

AEP's Chief Security Officer (CSO) leads the cyber security and physical security teams and is responsible for the design, implementation, and execution of AEP's security risk management strategy, including cyber security. AEP operates a Cyber Security Intelligence and Response Center (cyber security team) responsible for monitoring the AEP System for cyber threats. Among other things, the CSO and the cyber security team actively monitor best practices, perform penetration testing, lead response exercises and internal campaigns, and provide training and communication across the organization.

The cyber security team constantly scans the AEP System for risks and threats. It also continually reviews its business continuity plan to develop an effective recovery strategy that seeks to decrease response times, limit financial impacts and maintain customer confidence during any business interruption. The cyber security team works closely with a broad range of departments, including legal, regulatory, corporate communications and audit services and information technology.

The cyber security team collaborates with partners from both industry and government, and routinely participates in industry-wide programs that exchange knowledge of threats with utility peers, industry and federal agencies. AEP is a member of a number of industry specific threat and information sharing communities including the Department of Homeland Security and the Electricity Information Sharing and Analysis Center.

AEP has partnered in the past with a major defense contractor with significant cyber security experience and technical capabilities developed through their work with the U.S. Department of Defense. AEP continues to work with a nonaffiliated entity to conduct several discussions each year about recognizing and investigating cyber vulnerabilities.

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 2017 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

ACCOUNTING PRONOUNCEMENTS

See Note 2 - New Accounting Pronouncements for information related to accounting pronouncements adopted in 2018 and pronouncements effective in the future.

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, 2017:
MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2018

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
	(in millions)			
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2017	$42.1	$ (131.3)	$ 163.9	$74.7
Gain from Contracts Realized/Settled During the Period and Entered in a Prior Period	(29.3)	(3.4)	(16.7)	(49.4)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	15.1	15.1
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	7.0	7.0
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	94.8	40.6	—	135.4
Total MTM Risk Management Contract Net Assets (Liabilities) as of September 30, 2018	$107.6	$ (94.1)	$ 169.3	182.8
Commodity Cash Flow Hedge Contracts				(23.2)
Fair Value Hedge Contracts				(34.2)
Collateral Deposits				(13.1)
Total MTM Derivative Contract Net Assets as of September 30, 2018				$112.3

(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.

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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 credit agency ratings 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, 2018, credit exposure net of collateral to sub investment grade counterparties was approximately 6.5%, 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, 2018, 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	$491.4	$ 2.2	$ 489.2	3	$ 268.7
Noninvestment Grade	0.6	0.6	—	—	—
No External Ratings:					
Internal Investment Grade	122.5	—	122.5	3	77.8
Internal Noninvestment Grade	52.6	10.5	42.1	2	29.1
Total as of September 30, 2018	$667.1	$ 13.3	$ 653.8		

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, 2018, 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, 2018				Twelve Months Ended December 31, 2017			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$0.2	$1.8	$ 0.3	$0.1	$0.2	$0.5	$ 0.2	$0.1

VaR Model
Non-Trading Portfolio

Nine Months Ended September 30, 2018				Twelve Months Ended December 31, 2017			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$0.6	$16.5	$ 2.9	$0.4	$4.1	$6.5	$ 1.0	$0.3

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

AEP is exposed to interest rate market fluctuations in the normal course of business operations. AEP has outstanding short and long-term debt which is subject to a variable rate. AEP manages interest rate risk by limiting variable-rate exposures to a percentage of total debt, by entering into interest rate derivative instruments and by monitoring the effects of market changes in interest rates. For the nine months ended September 30, 2018 and 2017, a 100 basis point change in the benchmark rate on AEP’s variable rate debt would impact pretax interest expense annually by $25 million and $28 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2018 and 2017
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
REVENUES				
Vertically Integrated Utilities	$2,610.2	$ 2,453.8	$7,332.4	$ 6,819.3
Transmission and Distribution Utilities	1,180.9	1,149.7	3,450.0	3,242.7
Generation & Marketing	486.5	441.5	1,399.3	1,386.8
Other Revenues	55.5	59.7	212.9	165.7
TOTAL REVENUES	4,333.1	4,104.7	12,394.6	11,614.5
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	840.4	707.4	1,909.1	1,865.3
Purchased Electricity for Resale	784.7	718.1	2,551.7	2,156.9
Other Operation	826.0	644.0	2,332.7	1,884.1
Maintenance	316.6	269.0	911.0	862.6
Gain on Sale of Merchant Generation Assets	—	—	—	(226.4)
Depreciation and Amortization	602.6	518.5	1,695.5	1,485.9
Taxes Other Than Income Taxes	294.2	272.6	863.0	792.0
TOTAL EXPENSES	3,664.5	3,129.6	10,263.0	8,820.4
OPERATING INCOME	668.6	975.1	2,131.6	2,794.1
Other Income (Expense):				
Interest and Investment Income	5.4	2.4	11.3	12.7
Carrying Costs Income	0.9	2.6	7.2	14.2
Allowance for Equity Funds Used During Construction	30.9	20.0	92.4	62.2
Non-Service Cost Components of Net Periodic Benefit Cost	31.9	11.4	95.3	34.2
Gain on Sale of Equity Investment	—	12.4	—	12.4
Interest Expense	(256.8)	(223.3)	(733.1)	(668.0)
INCOME BEFORE INCOME TAX EXPENSE (CREDIT) AND EQUITY EARNINGS	480.9	800.6	1,604.7	2,261.8
Income Tax Expense (Credit)	(80.7)	264.0	93.5	797.8
Equity Earnings of Unconsolidated Subsidiaries	18.1	20.1	55.3	63.1
NET INCOME	579.7	556.7	1,566.5	1,527.1
Net Income Attributable to Noncontrolling Interests	2.1	12.0	6.1	15.2
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$577.6	$ 544.7	$1,560.4	$ 1,511.9

WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	492,984,744	491,840,722	492,649,456	491,781,643
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$1.17	$ 1.11	$3.17	$ 3.07
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	493,940,543	492,986,307	493,526,937	492,428,586
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$1.17	$ 1.10	$3.16	$ 3.07
CASH DIVIDENDS DECLARED PER SHARE	$0.62	$ 0.59	$1.86	$ 1.77

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2018	2017	2018	2017
Net Income	$579.7	$556.7	$1,566.5	$1,527.1
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $2.7 and $(8.1) for the Three Months Ended September 30, 2018 and 2017, Respectively, and $3.9 and $(12.2) for the Nine Months Ended September 30, 2018 and 2017, Respectively	10.2	(15.0)	14.7	(22.6)
Securities Available for Sale, Net of Tax of $0 and $0.5 for the Three Months Ended September 30, 2018 and 2017, Respectively, and $0 and $1.5 for the Nine Months Ended September 30, 2018 and 2017, Respectively	—	0.9	—	2.7
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.4) and $0.1 for the Three Months Ended September 30, 2018 and 2017, Respectively, and $(1.1) and $0.4 for the Nine Months Ended September 30, 2018 and 2017, Respectively	(1.4)	0.3	(4.0)	0.8
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	8.8	(13.8)	10.7	(19.1)
TOTAL COMPREHENSIVE INCOME	588.5	542.9	1,577.2	1,508.0
Total Comprehensive Income Attributable to Noncontrolling Interests	2.1	12.0	6.1	15.2
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$586.4	$530.9	$1,571.1	$1,492.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2018 and 2017
(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, 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
TOTAL EQUITY – DECEMBER 31, 2017	512.2	$3,329.4	$6,398.7	$8,626.7	$ (67.8)	$ 26.6	$18,313.6
Issuance of Common Stock	1.1	7.1	55.4				62.5
Common Stock Dividends				(919.3)		(3.2)	(922.5)
Other Changes in Equity			18.5			0.5	19.0
ASU 2018-02 Adoption				14.0	(17.0)		(3.0)
ASU 2016-01 Adoption				11.9	(11.9)		—
Net Income				1,560.4		6.1	1,566.5
Other Comprehensive Income					10.7		10.7
TOTAL EQUITY – SEPTEMBER 30, 2018	513.3	$3,336.5	$6,472.6	$9,293.7	$ (86.0)	$ 30.0	$19,046.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2018 and December 31, 2017
(in millions)
(Unaudited)

	September 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$788.3	$ 214.6
Restricted Cash (September 30, 2018 and December 31, 2017 Amounts Include $149.2 and $198, Respectively, Related to Transition Funding, Ohio Phase-in-Recovery Funding and Appalachian Consumer Rate Relief Funding)	149.2	198.0
Other Temporary Investments (September 30, 2018 and December 31, 2017 Amounts Include $157 and $155.4, Respectively, Related to EIS and Transource Energy)	164.1	161.7
Accounts Receivable:		
Customers	757.9	643.9
Accrued Unbilled Revenues	241.2	230.2
Pledged Accounts Receivable – AEP Credit	1,112.2	954.2
Miscellaneous	47.2	101.2
Allowance for Uncollectible Accounts	(40.4)	(38.5)
Total Accounts Receivable	2,118.1	1,891.0
Fuel	282.3	387.7
Materials and Supplies	565.6	565.5
Risk Management Assets	191.9	126.2
Regulatory Asset for Under-Recovered Fuel Costs	137.5	292.5
Margin Deposits	108.8	105.5
Prepayments and Other Current Assets	186.6	310.4
TOTAL CURRENT ASSETS	4,692.4	4,253.1
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	21,327.3	20,760.5
Transmission	20,113.7	18,972.5
Distribution	20,763.9	19,868.5
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	3,996.9	3,706.3
Construction Work in Progress	4,995.5	4,120.7
Total Property, Plant and Equipment	71,197.3	67,428.5
Accumulated Depreciation and Amortization	17,841.6	17,167.0
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	53,355.7	50,261.5
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,189.9	3,587.6
Securitized Assets	1,001.4	1,211.2
Spent Nuclear Fuel and Decommissioning Trusts	2,666.0	2,527.6
Goodwill	52.5	52.5

Long-term Risk Management Assets	264.9	282.1
Deferred Charges and Other Noncurrent Assets	2,394.6	2,553.5
TOTAL OTHER NONCURRENT ASSETS	9,569.3	10,214.5
TOTAL ASSETS	$67,617.4	$ 64,729.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2018 and December 31, 2017
(dollars in millions)
(Unaudited)

	September 30, 2018	December 31, 2017
CURRENT LIABILITIES		
Accounts Payable	$ 1,579.9	$ 2,065.3
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	750.0	718.0
Other Short-term Debt	1,492.6	920.6
Total Short-term Debt	2,242.6	1,638.6
Long-term Debt Due Within One Year (September 30, 2018 and December 31, 2017 Amounts Include $420.7 and $406.9, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Sabine)	1,904.2	1,753.7
Risk Management Liabilities	57.3	61.6
Customer Deposits	372.5	357.0
Accrued Taxes	774.1	1,115.5
Accrued Interest	299.8	234.5
Regulatory Liability for Over-Recovered Fuel Costs	66.9	11.9
Other Current Liabilities	1,128.9	1,033.2
TOTAL CURRENT LIABILITIES	8,426.2	8,271.3
NONCURRENT LIABILITIES		
Long-term Debt (September 30, 2018 and December 31, 2017 Amounts Include $1,110 and $1,410.5, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy, and Sabine)	20,869.8	19,419.6
Long-term Risk Management Liabilities	287.2	322.0
Deferred Income Taxes	7,110.4	6,813.9
Regulatory Liabilities and Deferred Investment Tax Credits	8,643.5	8,422.3
Asset Retirement Obligations	1,975.1	1,925.5
Employee Benefits and Pension Obligations	350.7	398.1
Deferred Credits and Other Noncurrent Liabilities	807.2	830.9
TOTAL NONCURRENT LIABILITIES	40,043.9	38,132.3
TOTAL LIABILITIES	48,470.1	46,403.6
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEZZANINE EQUITY		
Redeemable Noncontrolling Interest	70.0	—

Contingently Redeemable Performance Share Awards			30.5	11.9
TOTAL MEZZANINE EQUITY			100.5	11.9
EQUITY				
Common Stock – Par Value – $6.50 Per Share:				
	2018	2017		
Shares Authorized	600,000,000	600,000,000		
Shares Issued	513,301,636	512,210,644		
(20,204,160 and 20,205,046 Shares were Held in Treasury as of September 30, 2018 and December 31, 2017, Respectively)			3,336.5	3,329.4
Paid-in Capital			6,472.6	6,398.7
Retained Earnings			9,293.7	8,626.7
Accumulated Other Comprehensive Income (Loss)			(86.0)	(67.8)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			19,016.8	18,287.0
Noncontrolling Interests			30.0	26.6
TOTAL EQUITY			19,046.8	18,313.6
TOTAL LIABILITIES, MEZZANINE EQUITY AND TOTAL EQUITY			$67,617.4	$ 64,729.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2018		2017	
OPERATING ACTIVITIES				
Net Income	$ 1,566.5		$ 1,527.1	
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:				
Depreciation and Amortization	1,695.5		1,485.9	
Deferred Income Taxes	43.0		740.9	
Allowance for Equity Funds Used During Construction	(92.4	)	(62.2	)
Mark-to-Market of Risk Management Contracts	(95.4	)	(56.2	)
Amortization of Nuclear Fuel	82.6		104.8	
Pension Contributions to Qualified Plan Trust	—		(93.3	)
Property Taxes	304.8		291.4	
Deferred Fuel Over/Under-Recovery, Net	210.6		81.0	
Gain on Sale of Merchant Generation Assets	—		(226.4	)
Gain on Sale of Equity Investment	—		(12.4	)
Recovery of Ohio Capacity Costs	52.7		65.6	
Provision for Refund – Global Settlement, Net	(5.5	)	(93.3	)
Change in Other Noncurrent Assets	161.6		(334.6	)
Change in Other Noncurrent Liabilities	141.9		205.7	
Changes in Certain Components of Working Capital:				
Accounts Receivable, Net	(52.3	)	201.3	
Fuel, Materials and Supplies	98.7		58.5	
Accounts Payable	(45.0	)	(91.0	)
Accrued Taxes, Net	(247.5	)	(310.1	)
Other Current Assets	11.7		(98.2	)
Other Current Liabilities	101.1		(260.3	)
Net Cash Flows from Operating Activities	3,932.6		3,124.2	

INVESTING ACTIVITIES		
Construction Expenditures	(4,688.4)	(3,778.2)
Purchases of Investment Securities	(1,591.2)	(1,855.8)
Sales of Investment Securities	1,550.9	1,808.6
Acquisitions of Nuclear Fuel	(26.1)	(73.2)
Proceeds from Sale of Merchant Generation Assets	—	2,159.6
Other Investing Activities	66.1	16.3
Net Cash Flows Used for Investing Activities	(4,688.7)	(1,722.7)
FINANCING ACTIVITIES		
Issuance of Common Stock	62.5	—
Issuance of Long-term Debt	3,572.0	2,742.7
Commercial Paper and Credit Facility Borrowings	205.6	—
Change in Short-term Debt, Net	604.0	(653.7)
Retirement of Long-term Debt	(1,959.5)	(2,427.2)
Commercial Paper and Credit Facility Repayments	(205.6)	—
Make Whole Premium on Extinguishment of Long-term Debt	(10.3)	(46.1)
Principal Payments for Capital Lease Obligations	(49.4)	(50.5)
Dividends Paid on Common Stock	(922.5)	(875.0)
Other Financing Activities	(15.8)	(4.4)
Net Cash Flows from (Used for) Financing Activities	1,281.0	(1,314.2)
Net Increase in Cash, Cash Equivalents and Restricted Cash	524.9	87.3
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	412.6	403.5
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 937.5	$ 490.8
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 631.3	$ 613.8
Net Cash Paid (Received) for Income Taxes	(27.9)	(6.8)
	43.5	44.5

Noncash Acquisitions Under Capital Leases		
Construction Expenditures Included in Current Liabilities as of September 30,	882.3	791.6
Construction Expenditures Included in Noncurrent Liabilities as of September 30,	—	71.8
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	12.1	0.6
Noncash Contribution of Assets by Noncontrolling Interest	84.0	—
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	2.1	2.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

AEP TEXAS INC.
AND SUBSIDIARIES

AEP TEXAS INC. 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		Nine Months Ended	
	September 30,		September 30,	
	2018	2017	2018	2017
	(in millions of KWhs)			
Retail:				
Residential	3,893	3,867	9,679	9,163
Commercial	3,172	3,135	8,438	8,395
Industrial	2,054	1,867	6,243	6,025
Miscellaneous	159	157	430	429
Total Retail	9,278	9,026	24,790	24,012

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		Nine Months Ended	
	September 30,		September 30,	
	2018	2017	2018	2017
	(in degree days)			
Actual – Heating (a)	—	—	234	103
Normal – Heating (b)	—	—	194	199
Actual – Cooling (c)	1,424	1,393	2,612	2,640
Normal – Cooling (b)	1,367	1,364	2,413	2,396

(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 2018 Compared to Third Quarter of 2017
Reconciliation of Third Quarter of 2017 to Third Quarter of 2018
Net Income
(in millions)

Third Quarter of 2017	$64.3
Changes in Gross Margin:	
Retail Margins	(4.4)
Off-system Sales	3.7
Transmission Revenues	(0.6)
Other Revenues	(1.4)
Total Change in Gross Margin	(2.7)
Changes in Expenses and Other:	
Other Operation and Maintenance	(19.8)
Depreciation and Amortization	(9.3)
Taxes Other Than Income Taxes	(3.0)
Allowance for Equity Funds Used During Construction	5.8
Non-Service Cost Components of Net Periodic Benefit Cost	2.2
Interest Expense	(2.0)
Total Change in Expenses and Other	(26.1)
Income Tax Expense	22.3
Third Quarter of 2018	$57.8

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals were as follows:

- Retail Margins decreased $4 million primarily due to the following:
- A $6 million decrease due to lower weather-normalized margins.
- A $6 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.

These decreases were partially offset by:

- A $3 million increase in revenues associated with the Distribution Cost Recovery Factor revenue rider.
- A $2 million increase in revenues associated with the Transmission Cost Recovery Factor revenue rider. This increase was partially offset by an increase in Other Operation and Maintenance expenses below.
- A $2 million increase in weather-related usage primarily driven by a 2% increase in cooling degree days.
- Margins from Off-system Sales increased $4 million primarily due to higher affiliated PPA revenues, which were offset by a corresponding increase in Other Operation and Maintenance expenses below.
- Transmission Revenues decreased $1 million primarily due to the following:
- A $6 million decrease due to lower rates in order to pass the benefits of Tax Reform on to customers. This decrease was offset in Income Tax Expense below.

This decrease was offset by:

- A $6 million increase due to recovery of increased transmission investment in ERCOT.

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

- Other Operation and Maintenance expenses increased $20 million primarily due to the following:
- A $7 million increase in ERCOT transmission expenses. This increase was offset by an increase in Retail Margins above.
- A $6 million increase in employee-related expenses.
- A $5 million increase in affiliated PPA expenses. This increase was offset by an increase in Margins from Off-system sales above.
- Depreciation and Amortization expenses increased $9 million primarily due to the following:
- A $4 million increase due to a prior year asset retirement obligation revision for the Oklaunion Power Station.
- A $3 million increase in depreciation expense primarily due to an increase in the depreciable base of transmission and distribution assets.
- Taxes Other Than Income Taxes increased $3 million primarily due to increased property taxes as a result of additional capital investment and increased tax rates.
- Allowance for Equity Funds Used During Construction increased $6 million primarily due to increased transmission projects.
- Interest Expense increased $2 million primarily due to the following:
- An $8 million increase due to the issuances of long-term debt.

This increase was offset by:

- A $4 million decrease due to a higher debt component of AFUDC and increased investment primarily in transmission projects.
- A $2 million decrease in securitization assets related to Transition Funding. This decrease was offset above in Other Revenues and Depreciation and Amortization.
- Income Tax Expense decreased $22 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

Reconciliation of Nine Months Ended September 30, 2017 to Nine Months Ended September 30, 2018 Net Income (in millions)	
Nine Months Ended September 30, 2017	$ 146.6
Changes in Gross Margin:	
Retail Margins	16.1
Off-system Sales	2.0
Transmission Revenues	1.4
Other Revenues	(1.2)
Total Change in Gross Margin	18.3
Changes in Expenses and Other:	
Other Operation and Maintenance	(45.3)
Depreciation and Amortization	(21.9)
Taxes Other Than Income Taxes	(9.0)
Interest Income	(1.6)
Allowance for Equity Funds Used During Construction	13.0
Non-Service Cost Components of Net Periodic Benefit Cost	6.5
Interest Expense	(3.3)
Total Change in Expenses and Other	(61.6)
Income Tax Expense	47.8
Nine Months Ended September 30, 2018	$ 151.1

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

- Retail Margins increased $16 million primarily due to the following:
  - A $16 million increase in revenues associated with the Distribution Cost Recovery Factor revenue rider.
  - A $13 million increase in revenues associated with the Transmission Cost Recovery Factor revenue rider. This increase was partially offset by an increase in Other Operation and Maintenance expenses below.
  - A $13 million increase in weather-related usage primarily driven by a 127% increase in heating degree days partially offset by a 1% decrease in cooling degree days.

  These increases were partially offset by:
  - An $18 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
  - A $7 million decrease due to lower weather-normalized margins primarily in the residential class.
- Transmission Revenues increased $1 million primarily due to the following:
  - A $19 million increase due to recovery of increased transmission investment in ERCOT.

  This increase was partially offset by:
  - An $11 million decrease due to the 2018 provisions for customer refunds due to Tax Reform. This decrease was offset in Income Tax Expense below.
  - A $6 million decrease due to lower rates in order to pass the benefits of Tax Reform on to customers. This decrease was offset in Income Tax Expense below.

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

- Other Operation and Maintenance expenses increased $45 million primarily due to the following:
  - A $20 million increase in ERCOT transmission expenses. This increase was partially offset by an increase in Retail Margins above.
  - A $9 million increase in distribution expenses.
  - A $9 million increase in employee-related expenses.
  - A $5 million increase in affiliated PPA expenses. This increase was offset by an increase in Margins from Off-system sales above.
- Depreciation and Amortization expenses increased $22 million primarily due to the following:
  - An $11 million increase in depreciation expense primarily due to an increase in the depreciable base of transmission and distribution assets.
  - A $5 million increase in securitization amortizations related to Transition Funding. This increase was offset in Other Revenues above and Interest Expense below.
  - A $4 million increase due to a prior year asset retirement obligation revision for the Oklaunion Power Station.
  - A $3 million increase in amortization primarily due to advanced metering infrastructure projects and capitalized software.
- Taxes Other Than Income Taxes increased $9 million primarily due to increased property taxes as a result of additional capital investment and increased tax rates.
- Allowance for Equity Funds Used During Construction increased $13 million primarily due to increased transmission projects.
- Non-Service Cost Components of Net Periodic Cost decreased $7 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- Interest Expense increased $3 million primarily due to the following:
  - A $20 million increase due to the issuances of long-term debt.

  This increase was partially offset by:
  - A $10 million decrease due to a higher debt component of AFUDC and increased investment primarily in transmission projects.
  - An $8 million decrease in securitization assets related to Transition Funding. This decrease was offset above in Other Revenues and Depreciation and Amortization.
- Income Tax Expense decreased $48 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2018	2017	2018	2017
REVENUES				
Electric Transmission and Distribution	$404.5	$411.5	$1,127.0	$1,111.4
Sales to AEP Affiliates	27.5	18.9	63.3	50.8
Other Revenues	1.4	0.8	3.0	2.1
TOTAL REVENUES	433.4	431.2	1,193.3	1,164.3
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	13.2	8.3	27.9	17.2
Other Operation	133.4	117.5	368.4	332.8
Maintenance	23.2	19.3	67.8	58.1
Depreciation and Amortization	133.3	124.0	364.9	343.0
Taxes Other Than Income Taxes	36.3	33.3	102.3	93.3
TOTAL EXPENSES	339.4	302.4	931.3	844.4
OPERATING INCOME	94.0	128.8	262.0	319.9
Other Income (Expense):				
Interest Income	0.5	0.5	—	1.6
Allowance for Equity Funds Used During Construction	5.8	—	15.2	2.2
Non-Service Cost Components of Net Periodic Benefit Cost	3.1	0.9	9.2	2.7
Interest Expense	(37.3)	(35.3)	(108.9)	(105.6)
INCOME BEFORE INCOME TAX EXPENSE	66.1	94.9	177.5	220.8
Income Tax Expense	8.3	30.6	26.4	74.2
NET INCOME	$57.8	$64.3	$151.1	$146.6

The common stock of AEP Texas is wholly-owned by Parent.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

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AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Net Income	$57.8	$64.3	$151.1	$146.6
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.1 and $0.2 for the Three Months Ended September 30, 2018 and 2017, Respectively, and $0.2 and $0.4 for the Nine Months Ended September 30, 2018 and 2017, Respectively	0.3	0.2	0.8	0.7
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 for the Three Months Ended September 30, 2018 and 2017, Respectively, and $0 and $0.1 for the Nine Months Ended September 30, 2018 and 2017, Respectively	—	0.1	0.1	0.2
TOTAL OTHER COMPREHENSIVE INCOME	0.3	0.3	0.9	0.9
TOTAL COMPREHENSIVE INCOME	$58.1	$64.6	$152.0	$147.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$857.9	$814.1	$ (14.9)	$1,657.1
Capital Contribution from Parent	200.0			200.0
Net Income		146.6		146.6
Other Comprehensive Income			0.9	0.9
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2017	$1,057.9	$960.7	$ (14.0)	$2,004.6
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	$1,057.9	$1,124.6	$ (12.6)	$2,169.9
Capital Contribution from Parent	100.0			100.0
ASU 2018-02 Adoption		1.8	(2.7)	(0.9)
Net Income		151.1		151.1
Other Comprehensive Income			0.9	0.9
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2018	$1,157.9	$1,277.5	$ (14.4)	$2,421.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2018 and December 31, 2017
(in millions)
(Unaudited)

	September 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$0.1	$2.0
Restricted Cash for Securitized Transition Funding	124.2	155.2
Advances to Affiliates	8.0	111.9
Accounts Receivable:		
Customers	132.9	105.3
Affiliated Companies	14.3	12.3
Accrued Unbilled Revenues	73.7	75.8
Miscellaneous	0.5	1.3
Allowance for Uncollectible Accounts	(0.9)	(0.7)
Total Accounts Receivable	220.5	194.0
Fuel	6.9	3.6
Materials and Supplies	51.1	52.0
Risk Management Assets	0.5	0.5
Accrued Tax Benefits	14.6	41.0
Prepayments and Other Current Assets	12.0	3.6
TOTAL CURRENT ASSETS	437.9	563.8
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	352.1	350.7
Transmission	3,302.3	3,053.6
Distribution	3,968.4	3,718.6
Other Property, Plant and Equipment	554.0	461.0
Construction Work in Progress	1,108.8	835.7
Total Property, Plant and Equipment	9,285.6	8,419.6
Accumulated Depreciation and Amortization	1,643.9	1,594.5
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,641.7	6,825.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	396.4	378.7
Securitized Transition Assets (September 30, 2018 and December 31, 2017 Amounts Include $702.9 and $869.5, Respectively, Related to Transition Funding)	717.9	891.2
Deferred Charges and Other Noncurrent Assets	97.8	114.8
TOTAL OTHER NONCURRENT ASSETS	1,212.1	1,384.7
TOTAL ASSETS	$9,291.7	$8,773.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2018 and December 31, 2017
(in millions)
(Unaudited)

	September 30, 2018	December 31, 2017
CURRENT LIABILITIES		
Advances from Affiliates	$77.8	$—
Accounts Payable:		
General	208.8	379.4
Affiliated Companies	31.7	30.2
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2018 and December 31, 2017 Amounts Include $250.5 and $236.1, Respectively, Related to Transition Funding)	500.5	266.1
Accrued Taxes	90.8	77.2
Accrued Interest (September 30, 2018 and December 31, 2017 Amounts Include $9 and $15.9, Respectively, Related to Transition Funding)	54.3	42.2
Oklaunion Purchase Power Agreement	22.8	—
Other Current Liabilities	99.5	76.4
TOTAL CURRENT LIABILITIES	1,086.2	871.5
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (September 30, 2018 and December 31, 2017 Amounts Include $574.7 and $790.1, Respectively, Related to Transition Funding)	3,413.9	3,383.2
Deferred Income Taxes	902.3	913.1
Regulatory Liabilities and Deferred Investment Tax Credits	1,346.4	1,320.5
Oklaunion Purchase Power Agreement	28.7	52.0
Deferred Credits and Other Noncurrent Liabilities	93.2	63.4
TOTAL NONCURRENT LIABILITIES	5,784.5	5,732.2
TOTAL LIABILITIES	6,870.7	6,603.7
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Paid-in Capital	1,157.9	1,057.9
Retained Earnings	1,277.5	1,124.6
Accumulated Other Comprehensive Income (Loss)	(14.4)	(12.6)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,421.0	2,169.9
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$9,291.7	$8,773.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2018	2017
OPERATING ACTIVITIES		
Net Income	$151.1	$146.6
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	364.9	343.0
Deferred Income Taxes	(21.2)	124.1
Allowance for Equity Funds Used During Construction	(15.2)	(2.2)
Mark-to-Market of Risk Management Contracts	—	0.1
Pension Contributions to Qualified Plan Trust	—	(8.8)
Property Taxes	(19.2)	(15.9)
Change in Regulatory Asset – Catastrophe Reserve	(22.3)	(72.3)
Change in Other Noncurrent Assets	(14.2)	(29.1)
Change in Other Noncurrent Liabilities	67.1	7.4
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(26.5)	(47.6)
Fuel, Materials and Supplies	(2.4)	(0.1)
Accounts Payable	(19.1)	77.3
Accrued Taxes, Net	40.0	1.7
Other Current Assets	(6.3)	(2.5)
Other Current Liabilities	14.1	(31.2)
Net Cash Flows from Operating Activities	490.8	490.5
INVESTING ACTIVITIES		
Construction Expenditures	(1,096.1)	(617.5)
Change in Advances to Affiliates, Net	103.9	(437.0)
Other Investing Activities	31.1	11.5
Net Cash Flows Used for Investing Activities	(961.1)	(1,043.0)
FINANCING ACTIVITIES		
Capital Contribution from Parent	100.0	200.0
Issuance of Long-term Debt – Nonaffiliated	494.0	749.9
Change in Advances from Affiliates, Net	77.8	(169.5)
Retirement of Long-term Debt – Nonaffiliated	(231.7)	(248.4)
Principal Payments for Capital Lease Obligations	(3.6)	(3.0)
Other Financing Activities	0.9	(0.3)
Net Cash Flows from Financing Activities	437.4	528.7
Net Decrease in Cash, Cash Equivalents and Restricted Cash for Securitized Transition Funding	(32.9)	(23.8)
Cash, Cash Equivalents and Restricted Cash for Securitized Transition Funding at Beginning of Period	157.2	146.9
Cash, Cash Equivalents and Restricted Cash for Securitized Transition Funding at End of Period	$124.3	$123.1

SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$92.2	$101.1
Net Cash Paid (Received) for Income Taxes	(14.2)	(23.3)
Noncash Acquisitions Under Capital Leases	8.9	5.3
Construction Expenditures Included in Current Liabilities as of September 30,	176.4	166.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

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,	
	2018	2017
	(in millions)	
Plant In Service	$5,988.7	$4,664.1
Construction Work in Progress	1,772.9	1,393.0
Accumulated Depreciation and Amortization	234.6	134.0
Total Transmission Property, Net	$7,527.0	$5,923.1

Third Quarter of 2018 Compared to Third Quarter of 2017
Reconciliation of Third Quarter of 2017 to Third Quarter of 2018
Net Income
(in millions)

Third Quarter of 2017	$58.6
Changes in Transmission Revenues:	
Transmission Revenues	28.8
Total Change in Transmission Revenues	28.8
Changes in Expenses and Other:	
Other Operation and Maintenance	(7.5)
Depreciation and Amortization	(10.3)
Taxes Other Than Income Taxes	(7.6)
Interest Income	0.3
Allowance for Equity Funds Used During Construction	6.6
Interest Expense	(2.7)
Total Change in Expenses and Other	(21.2)
Income Tax Expense	11.9
Third Quarter of 2018	$78.1

The tables above reflect the revisions made to AEPTCo's previously issued financial statements. For additional details on the revisions to AEPTCo's financial statements, see Note 1 - Significant Accounting Matters.

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

- Transmission Revenues increased $29 million due to an increase in the formula rate revenue requirement primarily driven by continued investment in transmission assets. This increase includes the impact of the reduction in revenue related to Tax Reform, which was offset by a decrease in Income Tax Expense below.

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

- Other Operation and Maintenance expenses increased $8 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $10 million primarily due to a higher depreciable base.
- Taxes Other Than Income Taxes increased $8 million primarily due to higher property taxes as a result of increased transmission investment.
- Allowance for Equity Funds Used During Construction increased $7 million primarily due to increased transmission investment resulting in a higher CWIP balance.
- Interest Expense increased $3 million primarily due to the following:
  - A $5 million increase primarily due to higher long-term debt balances.

  This increase was partially offset by:
  - A $2 million decrease due to higher AFUDC borrowed funds resulting from a higher CWIP balance.
- Income Tax Expense decreased $12 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform and amortization of Excess ADIT, partially offset by an increase in pretax book income.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017
Reconciliation of Nine Months Ended September 30, 2017 to
Nine Months Ended September 30, 2018
Net Income
(in millions)

Nine Months Ended September 30, 2017	$212.4
Changes in Transmission Revenues:	
Transmission Revenues	51.4
Total Change in Transmission Revenues	51.4
Changes in Expenses and Other:	
Other Operation and Maintenance	(21.6)
Depreciation and Amortization	(27.8)
Taxes Other Than Income Taxes	(20.9)
Interest Income	0.8
Allowance for Equity Funds Used During Construction	15.7
Interest Expense	(10.3)
Total Change in Expenses and Other	(64.1)
Income Tax Expense	44.5
Nine Months Ended September 30, 2018	$244.2

The table above reflects the revisions made to AEPTCo's previously issued financial statements. For additional details on the revisions to AEPTCo's financial statements, see Note 1 - Significant Accounting Matters.

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

- Transmission Revenues increased $51 million primarily due to the following:
  - A $115 million increase in revenues due to an increase in the formula rate revenue requirement primarily driven by continued investment in transmission assets. This increase includes the impact of the reduction in revenue related to Tax Reform, which was offset by a decrease in Income Tax Expense below.

  This increase was partially offset by:
  - A $64 million decrease in revenues due to a lower annual formula rate true-up in 2018 driven by implementing forward looking formula rates in 2017.

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

- Other Operation and Maintenance expenses increased $22 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $28 million primarily due to a higher depreciable base.
- Taxes Other Than Income Taxes increased $21 million primarily due to higher property taxes as a result of increased transmission investment.
- Allowance for Equity Funds Used During Construction increased $16 million primarily due to increased transmission investment resulting in a higher CWIP balance.
- Interest Expense increased $10 million primarily due to the following:
  - A $16 million increase primarily due to higher long-term debt balances.

This increase was partially offset by:

- A $6 million decrease due to higher AFUDC borrowed funds resulting from a higher CWIP balance.
- Income Tax Expense decreased $45 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
REVENUES				
Transmission Revenues	$46.0	$35.6	$132.3	$95.7
Sales to AEP Affiliates	148.4	130.1	453.8	439.1
Other Revenues	—	(0.1)	0.1	—
TOTAL REVENUES	194.4	165.6	586.2	534.8
EXPENSES				
Other Operation	24.5	18.4	59.6	38.8
Maintenance	2.8	1.4	7.6	6.8
Depreciation and Amortization	34.9	24.6	97.5	69.7
Taxes Other Than Income Taxes	35.2	27.6	102.9	82.0
TOTAL EXPENSES	97.4	72.0	267.6	197.3
OPERATING INCOME	97.0	93.6	318.6	337.5
Other Income (Expense):				
Interest Income	0.5	0.2	1.3	0.5
Allowance for Equity Funds Used During Construction	18.0	11.4	48.7	33.0
Interest Expense	(19.8)	(17.1)	(60.7)	(50.4)
INCOME BEFORE INCOME TAX EXPENSE	95.7	88.1	307.9	320.6
Income Tax Expense	17.6	29.5	63.7	108.2
NET INCOME	$78.1	$58.6	$244.2	$212.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER’S EQUITY
For the Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Total
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		212.4	212.4
TOTAL MEMBER'S EQUITY – SEPTEMBER 30, 2017	$1,640.5	$715.0	$2,355.5
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2017	$1,816.6	$773.3	$2,589.9
Capital Contributions from Member	582.0		582.0
Net Income		244.2	244.2
TOTAL MEMBER'S EQUITY – SEPTEMBER 30, 2018	$2,398.6	$1,017.5	$3,416.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2018 and December 31, 2017
(in millions)
(Unaudited)

	September 30, 2018	December 31, 2017
CURRENT ASSETS		
Advances to Affiliates	$ 278.0	$ 146.3
Accounts Receivable:		
Customers	11.9	15.0
Affiliated Companies	73.0	93.2
Miscellaneous	1.1	1.3
Total Accounts Receivable	86.0	109.5
Materials and Supplies	16.4	13.6
Accrued Tax Benefits	29.8	49.4
Prepayments and Other Current Assets	3.5	7.6
TOTAL CURRENT ASSETS	413.7	326.4
TRANSMISSION PROPERTY		
Transmission Property	5,833.5	5,319.7
Other Property, Plant and Equipment	155.2	126.8
Construction Work in Progress	1,772.9	1,324.0
Total Transmission Property	7,761.6	6,770.5
Accumulated Depreciation and Amortization	234.6	152.6
TOTAL TRANSMISSION PROPERTY – NET	7,527.0	6,617.9
OTHER NONCURRENT ASSETS		
Regulatory Assets	15.3	11.7
Deferred Property Taxes	38.1	125.0
Deferred Charges and Other Noncurrent Assets	4.3	1.1
TOTAL OTHER NONCURRENT ASSETS	57.7	137.8
TOTAL ASSETS	$ 7,998.4	$ 7,082.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND MEMBER'S EQUITY
September 30, 2018 and December 31, 2017
(in millions)
(Unaudited)

	September 30, 2018	December 31, 2017
CURRENT LIABILITIES		
Advances from Affiliates	$ 1.1	$ 15.7
Accounts Payable:		
General	237.4	484.5
Affiliated Companies	79.0	66.1
Long-term Debt Due Within One Year – Nonaffiliated	50.0	50.0
Accrued Taxes	138.7	231.5
Accrued Interest	35.9	15.0
Other Current Liabilities	4.3	4.1
TOTAL CURRENT LIABILITIES	546.4	866.9
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,822.6	2,500.4
Deferred Income Taxes	684.4	600.4
Regulatory Liabilities	509.6	493.8
Deferred Credits and Other Noncurrent Liabilities	19.3	30.7
TOTAL NONCURRENT LIABILITIES	4,035.9	3,625.3
TOTAL LIABILITIES	4,582.3	4,492.2
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEMBER'S EQUITY		
Paid-in Capital	2,398.6	1,816.6
Retained Earnings	1,017.5	773.3
TOTAL MEMBER'S EQUITY	3,416.1	2,589.9
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 7,998.4	$ 7,082.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2018	2017
OPERATING ACTIVITIES		
Net Income	$244.2	$212.4
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	97.5	69.7
Deferred Income Taxes	76.3	191.9
Allowance for Equity Funds Used During Construction	(48.7)	(33.0)
Property Taxes	86.9	72.4
Long-term Accounts Receivable – Affiliated	(3.1)	(13.8)
Change in Other Noncurrent Assets	12.7	8.6
Change in Other Noncurrent Liabilities	18.0	25.7
Changes in Certain Components of Working Capital:		
Accounts Receivable	23.5	(40.8)
Materials and Supplies	(2.8)	(11.0)
Accounts Payable	3.3	20.4
Accrued Taxes, Net	(73.2)	(71.2)
Accrued Interest	20.9	18.4
Other Current Assets	(0.5)	(5.3)
Other Current Liabilities	(28.0)	0.5
Net Cash Flows from Operating Activities	427.0	444.9
INVESTING ACTIVITIES		
Construction Expenditures	(1,171.8)	(1,050.7)
Change in Advances to Affiliates, Net	(131.7)	(223.8)
Acquisitions of Assets	(13.2)	(3.8)
Other Investing Activities	1.2	0.9
Net Cash Flows Used for Investing Activities	(1,315.5)	(1,277.4)
FINANCING ACTIVITIES		
Capital Contributions from Member	582.0	185.5
Issuance of Long-term Debt – Nonaffiliated	321.1	618.3
Change in Advances from Affiliates, Net	(14.6)	28.7
Net Cash Flows from Financing Activities	888.5	832.5
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	$38.4	$30.4
Net Cash Paid (Received) for Income Taxes	(32.1)	(93.4)

Construction Expenditures Included in Current Liabilities as of September 30,	237.0	248.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

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,	
	2018	2017	2018	2017
	(in millions of KWhs)			
Retail:				
Residential	2,662	2,488	8,895	7,829
Commercial	1,721	1,673	4,996	4,805
Industrial	2,427	2,431	7,165	7,106
Miscellaneous	215	202	644	613
Total Retail	7,025	6,794	21,700	20,353
Wholesale	1,143	994	2,252	2,684
Total KWhs	8,168	7,788	23,952	23,037

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,	
	2018	2017	2018	2017
	(in degree days)			
Actual – Heating (a)	—	—	1,518	1,000
Normal – Heating (b)	2	2	1,410	1,420
Actual – Cooling (c)	950	805	1,495	1,180
Normal – Cooling (b)	814	812	1,184	1,179

(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 2018 Compared to Third Quarter of 2017
Reconciliation of Third Quarter of 2017 to Third Quarter of 2018
Net Income
(in millions)

Third Quarter of 2017	$86.0
Changes in Gross Margin:	
Retail Margins	(64.0)
Off-system Sales	1.4
Transmission Revenues	2.4
Other Revenues	(1.2)
Total Change in Gross Margin	(61.4)
Changes in Expenses and Other:	
Other Operation and Maintenance	(56.3)
Depreciation and Amortization	(2.9)
Taxes Other Than Income Taxes	(1.3)
Interest Income	0.1
Carrying Costs Income	(0.2)
Allowance for Equity Funds Used During Construction	1.4
Non-Service Cost Components of Net Periodic Benefit Cost	3.2
Interest Expense	(3.6)
Total Change in Expenses and Other	(59.6)
Income Tax Expense (Credit)	122.1
Third Quarter of 2018	$87.1

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 $64 million primarily due to the following:
  - A $78 million reduction in deferred fuel under-recovery related to the West Virginia Tax Reform settlement. This decrease was offset in Income Tax Expense (Credit) below.
  - An $11 million increase in deferred fuel related to recoverable PJM expenses that were offset below.
  - A $10 million increase in non-recoverable fuel expense related to Virginia legislation.

  These decreases were partially offset by:
  - A $17 million increase due to an adjustment to the 2018 provisions for customer refunds related to Tax Reform. This increase was partially offset in Other Operation and Maintenance expenses and Income Tax Expense (Credit) below.
  - A $15 million increase in weather-related usage primarily due to an 18% increase in cooling degree days.

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

- Other Operation and Maintenance expenses increased $56 million primarily due to the following:
  - A $39 million increase in expenses due to the extinguishment of regulatory asset balances as agreed to within the West Virginia Tax Reform settlement. This increase was partially offset in Retail Margins above and Income Tax Expense (Credit) below.

- An $8 million increase in employee-related expenses.
- Non-Service Cost Components of Net Periodic Benefit Cost decreased $3 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.

- Income Tax Expense (Credit) decreased $122 million primarily due to the impact of the West Virginia Tax Reform settlement, the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017
Reconciliation of Nine Months Ended September 30, 2017 to Nine
Months Ended September 30, 2018
Net Income
(in millions)

Nine Months Ended September 30, 2017	$248.7
Changes in Gross Margin:	
Retail Margins	(61.0)
Off-system Sales	1.7
Transmission Revenues	2.8
Other Revenues	(4.6)
Total Change in Gross Margin	(61.1)
Changes in Expenses and Other:	
Other Operation and Maintenance	(57.0)
Depreciation and Amortization	(15.4)
Taxes Other Than Income Taxes	(7.8)
Interest Income	0.2
Carrying Costs Income	0.2
Allowance for Equity Funds Used During Construction	3.4
Non-Service Cost Components of Net Periodic Benefit Cost	9.5
Interest Expense	(2.5)
Total Change in Expenses and Other	(69.4)
Income Tax Expense (Credit)	171.8
Nine Months Ended September 30, 2018	$290.0

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 $61 million primarily due to the following:
  - A $78 million reduction of deferred fuel under-recovery related to the West Virginia Tax Reform settlement. This decrease was offset in Income Tax Expense (Credit) below.
  - A $41 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was partially offset in Other Operation and Maintenance expenses and Income Tax Expense (Credit) below.
  - A $28 million increase in deferred fuel related to recoverable PJM expenses that were offset below.
  - A $10 million increase in non-recoverable fuel expense related to Virginia legislation.
  - A $5 million decrease in weather-normalized margins occurring across all retail classes.

  These decreases were partially offset by:
  - A $90 million increase in weather-related usage primarily driven by a 52% increase in heating degree days along with a 27% increase in cooling degree days.
  - A $6 million increase primarily due to increases from rate riders in Virginia. This increase was partially offset by an increase in Other Operation and Maintenance expenses.

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

- Other Operation and Maintenance expenses increased $57 million primarily due to the following:
- A $39 million increase in expenses due to the extinguishment of regulatory asset balances as agreed to within the West Virginia Tax Reform settlement. This increase was partially offset in Retail Margins above and Income Tax Expense (Credit) below.
- A $21 million increase in recoverable PJM expenses. This increase in expense was primarily offset within Retail Margins above.
- A $13 million increase in employee-related expenses.
- A $9 million increase in storm-related expenses.
- A $5 million increase in estimated expenses for claims related to asbestos exposure.

These increases were partially offset by:

- A $41 million decrease in PJM expenses primarily related to the annual formula rate true-up that will be refunded in future periods.
- Depreciation and Amortization expenses increased $15 million primarily due to a higher depreciable base.
- Taxes Other Than Income Taxes increased $8 million primarily due to an increase in property taxes due to additional investments in utility plant.
- Allowance for Equity Funds Used During Construction increased $3 million due to an increase in construction activity.
- Non-Service Cost Components of Net Periodic Benefit Cost decreased $10 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- Income Tax Expense (Credit) decreased $172 million primarily due to the impact of the West Virginia Tax Reform settlement, the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2018	2017	2018	2017
REVENUES				
Electric Generation, Transmission and Distribution	$716.8	$674.4	$2,103.1	$2,045.0
Sales to AEP Affiliates	42.9	41.9	138.7	130.6
Other Revenues	2.3	3.0	7.6	11.8
TOTAL REVENUES	762.0	719.3	2,249.4	2,187.4
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	263.4	178.6	487.7	498.3
Purchased Electricity for Resale	80.4	61.1	350.8	217.1
Other Operation	131.9	117.0	380.0	370.1
Maintenance	97.2	55.8	234.9	187.8
Depreciation and Amortization	105.7	102.8	319.5	304.1
Taxes Other Than Income Taxes	33.6	32.3	101.1	93.3
TOTAL EXPENSES	712.2	547.6	1,874.0	1,670.7
OPERATING INCOME	49.8	171.7	375.4	516.7
Other Income (Expense):				
Interest Income	0.4	0.3	1.3	1.1
Carrying Costs Income	0.2	0.4	1.2	1.0
Allowance for Equity Funds Used During Construction	4.1	2.7	9.6	6.2
Non-Service Cost Components of Net Periodic Benefit Cost	4.5	1.3	13.4	3.9
Interest Expense	(50.8)	(47.2)	(146.0)	(143.5)
INCOME BEFORE INCOME TAX EXPENSE (CREDIT)	8.2	129.2	254.9	385.4
Income Tax Expense (Credit)	(78.9)	43.2	(35.1)	136.7
NET INCOME	$87.1	$86.0	$290.0	$248.7

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

See Condensed Notes to

Condensed
Financial
Statements of
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APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Net Income	$87.1	$86.0	$290.0	$248.7
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, 2018 and 2017, Respectively, and $(0.2) and $(0.3) for the Nine Months Ended September 30, 2018 and 2017, Respectively	(0.3)	(0.1)	(0.7)	(0.5)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.2) and $(0.1) for the Three Months Ended September 30, 2018 and 2017, Respectively, and $(0.6) and $(0.4) for the Nine Months Ended September 30, 2018 and 2017, Respectively	(0.7)	(0.3)	(2.3)	(0.9)
TOTAL OTHER COMPREHENSIVE LOSS	(1.0)	(0.4)	(3.0)	(1.4)
TOTAL COMPREHENSIVE INCOME	$86.1	$85.6	$287.0	$247.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	$ 260.4	$ 1,828.7	$ 1,714.1	$ 1.3	$ 3,804.5
Common Stock Dividends			(120.0)		(120.0)
ASU 2018-02 Adoption			0.1	0.3	0.4
Net Income			290.0		290.0
Other Comprehensive Loss				(3.0)	(3.0)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2018	$ 260.4	$ 1,828.7	$ 1,884.2	$ (1.4)	$ 3,971.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2018 and December 31, 2017
(in millions)
(Unaudited)

	September 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$2.2	$ 2.9
Restricted Cash for Securitized Funding	9.9	16.3
Advances to Affiliates	23.1	23.5
Accounts Receivable:		
Customers	155.7	123.1
Affiliated Companies	70.6	69.3
Accrued Unbilled Revenues	52.6	74.1
Miscellaneous	0.9	1.1
Allowance for Uncollectible Accounts	(4.0)	(3.7)
Total Accounts Receivable	275.8	263.9
Fuel	37.7	89.3
Materials and Supplies	98.4	99.5
Risk Management Assets	68.4	24.9
Regulatory Asset for Under-Recovered Fuel Costs	79.9	88.8
Margin Deposits	12.5	14.4
Prepayments and Other Current Assets	23.0	12.7
TOTAL CURRENT ASSETS	630.9	636.2
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,490.0	6,446.9
Transmission	3,141.2	3,019.9
Distribution	3,897.2	3,763.8
Other Property, Plant and Equipment	461.4	427.9
Construction Work in Progress	602.1	483.0
Total Property, Plant and Equipment	14,591.9	14,141.5
Accumulated Depreciation and Amortization	4,086.2	3,896.4
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	10,505.7	10,245.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	475.3	573.9
Securitized Assets	264.5	282.3
Long-term Risk Management Assets	1.4	1.1
Deferred Charges and Other Noncurrent Assets	180.1	190.0
TOTAL OTHER NONCURRENT ASSETS	921.3	1,047.3
TOTAL ASSETS	$12,057.9	$ 11,928.6

See
Condensed

Notes to Condensed Financial Statements of Registrants beginning on page 141.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2018 and December 31, 2017
(Unaudited)

	September 30, 2018	December 31, 2017
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$98.5	$ 186.0
Accounts Payable:		
General	219.1	264.9
Affiliated Companies	73.6	92.7
Long-term Debt Due Within One Year – Nonaffiliated	430.7	249.2
Risk Management Liabilities	0.9	1.3
Customer Deposits	88.0	86.1
Accrued Taxes	81.5	94.5
Accrued Interest	72.6	40.5
Other Current Liabilities	151.6	109.0
TOTAL CURRENT LIABILITIES	1,216.5	1,124.2
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,631.0	3,730.9
Long-term Risk Management Liabilities	0.7	0.2
Deferred Income Taxes	1,581.5	1,565.7
Regulatory Liabilities and Deferred Investment Tax Credits	1,423.8	1,454.9
Asset Retirement Obligations	103.2	100.2
Employee Benefits and Pension Obligations	65.7	73.3
Deferred Credits and Other Noncurrent Liabilities	63.6	74.7
TOTAL NONCURRENT LIABILITIES	6,869.5	6,999.9
TOTAL LIABILITIES	8,086.0	8,124.1
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	1,884.2	1,714.1
Accumulated Other Comprehensive Income (Loss)	(1.4)	1.3
TOTAL COMMON SHAREHOLDER'S EQUITY	3,971.9	3,804.5
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$12,057.9	$ 11,928.6

See
Condensed

Notes to Condensed Financial Statements of Registrants beginning on page 141.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2018	2017
OPERATING ACTIVITIES		
Net Income	$290.0	$248.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	319.5	304.1
Deferred Income Taxes	(83.8)	121.7
Allowance for Equity Funds Used During Construction	(9.6)	(6.2)
Mark-to-Market of Risk Management Contracts	(43.7)	(28.3)
Pension Contributions to Qualified Plan Trust	—	(10.2)
Deferred Fuel Over/Under-Recovery, Net	12.8	4.9
Change in Other Noncurrent Assets	94.8	37.1
Change in Other Noncurrent Liabilities	3.8	7.9
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	39.4	39.9
Fuel, Materials and Supplies	53.0	14.0
Accounts Payable	(21.5)	6.2
Accrued Taxes, Net	(20.2)	(44.2)
Other Current Assets	(7.9)	(2.5)
Other Current Liabilities	64.1	9.1
Net Cash Flows from Operating Activities	690.7	702.2
INVESTING ACTIVITIES		
Construction Expenditures	(575.8)	(560.0)
Change in Advances to Affiliates, Net	0.4	0.5
Other Investing Activities	10.0	11.8
Net Cash Flows Used for Investing Activities	(565.4)	(547.7)
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Nonaffiliated	103.3	320.9
Change in Advances from Affiliates, Net	(87.5)	(10.1)
Retirement of Long-term Debt - Nonaffiliated	(24.0)	(377.9)
Principal Payments for Capital Lease Obligations	(5.2)	(5.2)
Dividends Paid on Common Stock	(120.0)	(90.0)
Other Financing Activities	1.0	0.5
Net Cash Flows Used for Financing Activities	(132.4)	(161.8)
Net Decrease in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	(7.1)	(7.3)
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	19.2	18.5
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$12.1	$11.2

SUPPLEMENTARY INFORMATION

Cash Paid for Interest, Net of Capitalized Amounts	$104.5	$107.1
Net Cash Paid for Income Taxes	26.7	24.4
Noncash Acquisitions Under Capital Leases	3.9	2.9
Construction Expenditures Included in Current Liabilities as of September 30,	87.6	107.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

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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,	
	2018	2017	2018	2017
	(in millions of KWhs)			
Retail:				
Residential	1,562	1,404	4,430	4,015
Commercial	1,363	1,313	3,748	3,640
Industrial	2,003	1,978	5,880	5,793
Miscellaneous	15	16	50	50
Total Retail	4,943	4,711	14,108	13,498
Wholesale	2,613	2,807	7,927	8,567
Total KWhs	7,556	7,518	22,035	22,065

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,	
	2018	2017	2018	2017
	(in degree days)			
Actual – Heating (a)	2	—	2,523	1,816
Normal – Heating (b)	10	11	2,413	2,430
Actual – Cooling (c)	722	504	1,084	764
Normal – Cooling (b)	574	574	837	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 2018 Compared to Third Quarter of 2017
Reconciliation of Third Quarter of 2017 to Third Quarter of 2018
Net Income
(in millions)

Third Quarter of 2017	$64.9
Changes in Gross Margin:	
Retail Margins	42.4
Off-system Sales	(3.8)
Transmission Revenues	1.8
Other Revenues	(1.5)
Total Change in Gross Margin	38.9
Changes in Expenses and Other:	
Other Operation and Maintenance	(13.0)
Depreciation and Amortization	(30.2)
Taxes Other Than Income Taxes	0.9
Interest Income	1.4
Carrying Cost Income	(1.6)
Allowance for Equity Funds Used During Construction	0.4
Non-Service Cost Components of Net Periodic Benefit Cost	3.1
Interest Expense	(7.0)
Total Change in Expenses and Other	(46.0)
Income Tax Expense	14.9
Third Quarter of 2018	$72.7

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

- Retail Margins increased $42 million primarily due to the following:
- A $47 million increase from rate proceedings in the I&M service territory, inclusive of a $22 million decrease due to the impact of Tax Reform in the Indiana jurisdiction. The increase in Retail Margins relating to riders had corresponding increases in other expense items below.
- A $21 million increase in weather-related usage primarily due to a 43% increase in cooling degree days.

These increases were partially offset by:

- A $15 million decrease related to over/under recovery of riders.
- A $4 million decrease due to timing differences in the recovery of increased fuel and other variable production costs not related to fuel clauses or other trackers.
- A $3 million decrease due to customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
- A $3 million decrease due to lower weather-normalized margins primarily due to wholesale customer load loss from contracts that expired at the end of 2017.
- Margins from Off-system Sales decreased $4 million primarily due to mid-year changes in the OSS sharing mechanism.

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

- Other Operation and Maintenance expenses increased $13 million primarily due to the following:
  - A $5 million increase in demand-side management expenses. This increase was offset within Retail Margins above.
  - A $5 million increase in distribution forestry expenses.
  - A $4 million increase in Cook Plant refueling outage amortization expense, primarily due to increased costs of outages.
  - A $4 million increase in employee-related expenses.

  These increases were partially offset by:
  - A $5 million decrease in transmission expenses primarily due to a decrease in recoverable PJM expenses. This decrease was partially offset within Retail Margins above.
- Depreciation and Amortization expenses increased $30 million primarily due to a higher depreciable base and increased depreciation rates approved in the 2017 Indiana and Michigan base rate cases.
- Non-Service Cost Components of Net Periodic Benefit Cost decreased $3 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- Interest Expense increased $7 million primarily due to increased long-term debt balances.
- Income Tax Expense decreased $15 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017
Reconciliation of Nine Months Ended September 30, 2017 to Nine
Months Ended September 30, 2018
Net Income
(in millions)

Nine Months Ended September 30, 2017	$143.8
Changes in Gross Margin:	
Retail Margins	105.3
Off-system Sales	(5.4)
Transmission Revenues	23.3
Other Revenues	(3.2)
Total Change in Gross Margin	120.0
Changes in Expenses and Other:	
Other Operation and Maintenance	(2.5)
Depreciation and Amortization	(52.3)
Taxes Other Than Income Taxes	(4.6)
Interest Income	1.2
Carrying Cost Income	(5.3)
Allowance for Equity Funds Used During Construction	(0.1)
Non-Service Cost Components of Net Periodic Benefit Cost	9.0
Interest Expense	(12.6)
Total Change in Expenses and Other	(67.2)
Income Tax Expense	35.0
Nine Months Ended September 30, 2018	$231.6

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

- Retail Margins increased $105 million primarily due to the following:
  - An $89 million increase from rate proceedings in the I&M service territory, inclusive of a $26 million decrease due to the impact of Tax Reform in the Indiana jurisdiction. The increase in Retail Margins relating to riders had corresponding increases in other expense items below.
  - A $51 million increase in weather-related usage primarily due to a 39% increase in heating degree days and a 42% increase in cooling degree days.
  - A $32 million increase in FERC generation wholesale municipal and cooperative revenues primarily due to the annual formula rate true-up and changes to the formula rate.

  These increases were partially offset by:
  - A $30 million decrease related to over/under recovery of riders.
  - A $14 million decrease due to customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
  - A $10 million decrease due to timing differences in the recovery of increased fuel and other variable production costs not related to fuel clauses or other trackers.
- Margins from Off-system Sales decreased $5 million primarily due to mid-year changes in the OSS sharing mechanism.

- Transmission Revenues increased $23 million primarily due to the annual formula rate true-up and decreased RTO provisions.

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

- Other Operation and Maintenance expenses increased $3 million primarily due to the following:
  - A $10 million increase in Cook Plant refueling outage amortization expense, primarily due to increased costs of outages.
  - A $7 million increase in employee-related expenses.
  - A $6 million increase in distribution forestry expenses.
  - A $5 million increase in demand-side management expenses. This increase was offset within Retail Margins above.

  These increases were partially offset by:
  - A $19 million decrease in transmission expenses primarily due to the annual formula rate true-up.
  - A $7 million decrease due to an increased Nuclear Electric Insurance Limited distribution in 2018.
- Depreciation and Amortization expenses increased $52 million primarily due to a higher depreciable base and increased depreciation rates approved in the 2017 Indiana and Michigan base rate cases.
- Taxes Other Than Income Taxes increased $5 million primarily due to increased state taxes due to higher reported taxable KWh and taxable revenues and a prior period refund.
- Carrying Cost Income decreased $5 million primarily due to a decrease in carrying charges for certain riders in Indiana.
- Non-Service Cost Components of Net Periodic Benefit Cost decreased $9 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- Interest Expense increased $13 million primarily due to increased long-term debt balances.
- Income Tax Expense decreased $35 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform and amortization of Excess ADIT, partially offset by an increase in pretax book income.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2018	2017	2018	2017
REVENUES				
Electric Generation, Transmission and Distribution	$609.9	$537.0	$1,723.9	$1,527.4
Other Revenues – Affiliated	17.1	17.1	62.2	48.2
Other Revenues – Nonaffiliated	2.7	3.6	10.1	9.9
TOTAL REVENUES	629.7	557.7	1,796.2	1,585.5
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	95.9	76.4	246.8	238.2
Purchased Electricity for Resale	48.9	32.9	167.7	101.2
Purchased Electricity from AEP Affiliates	60.0	62.4	181.8	166.2
Other Operation	149.3	142.0	425.8	438.8
Maintenance	57.2	51.5	169.1	153.6
Depreciation and Amortization	85.2	55.0	207.1	154.8
Taxes Other Than Income Taxes	23.0	23.9	72.9	68.3
TOTAL EXPENSES	519.5	444.1	1,471.2	1,321.1
OPERATING INCOME	110.2	113.6	325.0	264.4
Other Income (Expense):				
Interest Income	1.6	0.2	2.8	1.6
Carrying Costs Income	0.6	2.2	4.6	9.9
Allowance for Equity Funds Used During Construction	3.9	3.5	8.0	8.1
Non-Service Cost Components of Net Periodic Benefit Cost	4.6	1.5	13.6	4.6
Interest Expense	(34.5)	(27.5)	(95.6)	(83.0)
INCOME BEFORE INCOME TAX EXPENSE	86.4	93.5	258.4	205.6
Income Tax Expense	13.7	28.6	26.8	61.8
NET INCOME	$72.7	$64.9	$231.6	$143.8

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2018	2017	2018	2017
Net Income	$72.7	$64.9	$231.6	$143.8
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, 2018 and 2017, Respectively, and $0.3 and $0.5 for the Nine Months Ended September 30, 2018 and 2017, Respectively	0.3	0.3	1.2	1.0
TOTAL COMPREHENSIVE INCOME	$73.0	$65.2	$232.8	$144.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

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INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	$ 56.6	$ 980.9	$ 1,192.2	$ (12.1)	$ 2,217.6
Common Stock Dividends			(105.5)		(105.5)
ASU 2018-02 Adoption			0.3	(2.7)	(2.4)
Net Income			231.6		231.6
Other Comprehensive Income				1.2	1.2
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2018	$ 56.6	$ 980.9	$ 1,318.6	$ (13.6)	$ 2,342.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2018 and December 31, 2017
(in millions)
(Unaudited)

	September 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$1.6	$ 1.3
Advances to Affiliates	72.5	12.4
Accounts Receivable:		
Customers	70.5	56.4
Affiliated Companies	51.7	50.0
Accrued Unbilled Revenues	16.1	7.3
Miscellaneous	1.9	2.0
Allowance for Uncollectible Accounts	(0.2)	(0.1)
Total Accounts Receivable	140.0	115.6
Fuel	28.7	31.4
Materials and Supplies	165.7	160.6
Risk Management Assets	10.9	7.6
Accrued Tax Benefits	35.4	58.4
Regulatory Asset for Under-Recovered Fuel Costs	0.1	15.0
Accrued Reimbursement of Spent Nuclear Fuel Costs	7.9	10.8
Prepayments and Other Current Assets	20.9	20.9
TOTAL CURRENT ASSETS	483.7	434.0
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,579.9	4,445.9
Transmission	1,543.3	1,504.0
Distribution	2,183.9	2,069.3
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	584.7	595.2
Construction Work in Progress	458.6	460.2
Total Property, Plant and Equipment	9,350.4	9,074.6
Accumulated Depreciation, Depletion and Amortization	3,113.9	3,024.2
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,236.5	6,050.4
OTHER NONCURRENT ASSETS		
Regulatory Assets	545.3	579.4
Spent Nuclear Fuel and Decommissioning Trusts	2,666.0	2,527.6
Long-term Risk Management Assets	0.9	0.7
Deferred Charges and Other Noncurrent Assets	175.7	179.9
TOTAL OTHER NONCURRENT ASSETS	3,387.9	3,287.6
TOTAL ASSETS	$10,108.1	$ 9,772.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

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INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2018 and December 31, 2017
(dollars in millions)
(Unaudited)

	September 30, 2018	December 31, 2017
CURRENT LIABILITIES		
Advances from Affiliates	$—	$ 211.6
Accounts Payable:		
General	142.6	154.5
Affiliated Companies	65.6	98.3
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2018 and December 31, 2017 Amounts Include $94.2 and $96.3, Respectively, Related to DCC Fuel)	172.7	474.7
Risk Management Liabilities	6.4	3.5
Customer Deposits	37.0	37.7
Accrued Taxes	44.7	81.3
Accrued Interest	22.2	37.5
Other Current Liabilities	129.8	112.2
TOTAL CURRENT LIABILITIES	621.0	1,211.3
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,889.7	2,270.4
Long-term Risk Management Liabilities	0.4	0.1
Deferred Income Taxes	1,010.0	953.8
Regulatory Liabilities and Deferred Investment Tax Credits	1,791.9	1,708.7
Asset Retirement Obligations	1,365.1	1,321.6
Deferred Credits and Other Noncurrent Liabilities	87.5	88.5
TOTAL NONCURRENT LIABILITIES	7,144.6	6,343.1
TOTAL LIABILITIES	7,765.6	7,554.4
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	1,318.6	1,192.2
Accumulated Other Comprehensive Income (Loss)	(13.6)	(12.1)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,342.5	2,217.6
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$10,108.1	$ 9,772.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Nine Months Ended September 30,					
	2018			2017		
OPERATING ACTIVITIES						
Net Income	$	231.6		$	143.8	
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:						
Depreciation and Amortization	207.1			154.8		
Deferred Income Taxes	28.1			132.2		
Amortization of Incremental Nuclear Refueling Outage Expenses, Net	13.5			15.5		
Carrying Costs Income	(4.6		)	(9.9		)
Allowance for Equity Funds Used During Construction	(8.0		)	(8.1		)
Mark-to-Market of Risk Management Contracts	(0.3		)	(7.5		)
Amortization of Nuclear Fuel	82.6			104.8		
Pension Contribution to Qualified Plan Trust	—			(13.0		)
Deferred Fuel Over/Under-Recovery, Net	29.6			22.0		
Change in Other Noncurrent Assets	(7.4		)	(32.2		)
Change in Other Noncurrent Liabilities	46.3			40.9		
Changes in Certain Components of Working Capital:						
Accounts Receivable, Net	6.5			19.3		
Fuel, Materials and Supplies	(1.1		)	(4.1		)
Accounts Payable	(34.7		)	16.6		
Customer Deposits	(0.7		)	3.0		
Accrued Taxes, Net	(7.1		)	(30.2		)
Accrued Interest	(15.3		)	(17.4		)
Other Current Assets	4.9			8.0		
Other Current Liabilities	0.3			(14.2		)
Net Cash Flows from Operating Activities	571.3			524.3		
INVESTING ACTIVITIES						
Construction Expenditures	(434.5		)	(469.2		)
	(60.1		)	(0.1		)

Change in Advances to Affiliates, Net		
Purchases of Investment Securities	(1,589.0)	(1,842.2)
Sales of Investment Securities	1,550.9	1,808.6
Acquisitions of Nuclear Fuel	(26.1)	(73.2)
Other Investing Activities	9.2	7.3
Net Cash Flows Used for Investing Activities	(549.6)	(568.8)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	1,168.1	411.1
Change in Advances from Affiliates, Net	(211.6)	(37.7)
Retirement of Long-term Debt – Nonaffiliated	(856.1)	(227.1)
Principal Payments for Capital Lease Obligations	(7.3)	(8.7)
Dividends Paid on Common Stock	(105.5)	(93.7)
Other Financing Activities	(9.0)	0.7
Net Cash Flows from (Used for) Financing Activities	(21.4)	44.6
Net Increase in Cash and Cash Equivalents	0.3	0.1
Cash and Cash Equivalents at Beginning of Period	1.3	1.2
Cash and Cash Equivalents at End of Period	$ 1.6	$ 1.3
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 104.4	$ 92.0
Net Cash Paid (Received) for Income Taxes	(26.5)	(69.6)
Noncash Acquisitions Under Capital Leases	4.4	5.9
Construction Expenditures Included in Current Liabilities as of September 30,	66.4	74.5
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	12.1	0.6
Expected Reimbursement for Capital Cost of Spent Nuclear Fuel Dry Cask Storage	2.1	2.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

OHIO POWER COMPANY AND SUBSIDIARIES

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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,	
	2018	2017	2018	2017
	(in millions of KWhs)			
Retail:				
Residential	4,055	3,644	11,475	10,198
Commercial	3,993	3,806	11,196	10,789
Industrial	3,666	3,708	11,016	10,967
Miscellaneous	27	28	84	87
Total Retail (a)	11,741	11,186	33,771	32,041
Wholesale (b)	634	585	1,835	1,749
Total KWhs	12,375	11,771	35,606	33,790

(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,	
	2018	2017	2018	2017
	(in degree days)			
Actual – Heating (a)	—	—	2,158	1,500
Normal – Heating (b)	6	6	2,076	2,091
Actual – Cooling (c)	864	642	1,322	957
Normal – Cooling (b)	670	670	964	960

(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 2018 Compared to Third Quarter of 2017
Reconciliation of Third Quarter of 2017 to Third Quarter of 2018
Net Income
(in millions)

Third Quarter of 2017	$82.6
Changes in Gross Margin:	
Retail Margins	25.7
Off-system Sales	12.3
Transmission Revenues	(0.2)
Other Revenues	2.1
Total Change in Gross Margin	39.9
Changes in Expenses and Other:	
Other Operation and Maintenance	(93.8)
Depreciation and Amortization	(13.1)
Taxes Other Than Income Taxes	(6.5)
Interest Income	0.1
Carrying Costs Income	(0.3)
Allowance for Equity Funds Used During Construction	1.1
Non-Service Cost Components of Net Periodic Benefit Cost	2.7
Interest Expense	(0.4)
Total Change in Expenses and Other	(110.2)
Income Tax Expense (Credit)	76.4
Third Quarter of 2018	$88.7

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

- Retail Margins increased $26 million primarily due to the following:
  - A $46 million net increase in Basic Transmission Cost Rider revenues and recoverable PJM expenses. This increase was partially offset by an increase in Other Operation and Maintenance expenses below.
  - A $21 million increase in revenues associated with the Universal Service Fund (USF). This increase was offset by a corresponding increase in Other Operation and Maintenance expenses below.
  - A $7 million increase in revenues associated with smart grid riders. This increase was partially offset by an increase in various expenses below.
  - A $6 million increase due to the reversal of a portion of the 2018 provisions for customer refunds primarily related to the October 2018 Ohio Tax Reform settlement. This increase was partially offset in Income Tax Expense (Credit) below.
  - A $4 million increase in rider revenues associated with the DIR. This increase was partially offset in various expenses below.

  These increases were partially offset by:
  - A $46 million decrease due to adjustments to the distribution decoupling under-recovery balance as a result of the 2018 Ohio Tax Reform settlement. This decrease was offset in Income Tax Expense (Credit) below.
  - A $12 million decrease due to the recovery of lower current year losses from a power contract with OVEC. This decrease was offset by a corresponding increase in Margins from Off-system Sales below.

- Margins from Off-system Sales increased $12 million primarily due to lower 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.

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

- Other Operation and Maintenance expenses increased $94 million primarily due to the following:
  - A $50 million increase in recoverable PJM expenses. This increase was offset within Gross Margins above.
  - A $21 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in Retail Margins above.
- Depreciation and Amortization expenses increased $13 million primarily due to the following:
  - A $6 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
  - A $4 million increase in recoverable smart grid depreciation expenses. This increase was offset in Retail Margins above.
- Taxes Other Than Income Taxes increased $7 million primarily due to the following:
  - A $3 million increase in rider revenues recovering state excise taxes due to an increase in metered KWh. This increase was offset by a corresponding increase in Retail Margins above.
  - A $3 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.
- Income Tax Expense (Credit) decreased $76 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

Reconciliation of Nine Months Ended September 30, 2017 to Nine Months Ended September 30, 2018
Net Income
(in millions)

Nine Months Ended September 30, 2017	$231.1
Changes in Gross Margin:	
Retail Margins	121.6
Off-system Sales	30.5
Transmission Revenues	(9.0)
Other Revenues	0.6
Total Change in Gross Margin	143.7
Changes in Expenses and Other:	
Other Operation and Maintenance	(211.8)
Depreciation and Amortization	(34.6)
Taxes Other Than Income Taxes	(17.2)
Interest Income	(1.4)
Carrying Costs Income	(1.5)
Allowance for Equity Funds Used During Construction	3.7
Non-Service Cost Components of Net Periodic Benefit Cost	8.3
Interest Expense	0.2
Total Change in Expenses and Other	(254.3)
Income Tax Expense (Credit)	116.6
Nine Months Ended September 30, 2018	$237.1

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

- Retail Margins increased $122 million primarily due to the following:
  - A $155 million net increase in Basic Transmission Cost Rider revenues and recoverable PJM expenses. This increase was partially offset by an increase in Other Operation and Maintenance expenses below.
  - A $61 million increase in revenues associated with the Universal Service Fund (USF). This increase was offset by a corresponding increase in Other Operation and Maintenance expenses below.
  - An $18 million increase in rider revenues associated with the DIR. This increase was partially offset in various expenses below.
  - A $9 million increase in usage primarily in the residential class.
  - An $8 million increase in rider revenues recovering state excise taxes due to an increase in metered KWh. This increase was offset by a corresponding increase in Taxes Other Than Income Taxes below.

  These increases were partially offset by:
  - A $46 million decrease due to adjustments to the distribution decoupling under-recovery balance as a result of the 2018 Ohio Tax Reform settlement. This decrease was offset in Income Tax Expense (Credit) below.
  - A $30 million decrease due to the recovery of lower current year losses from a power contract with OVEC. This decrease was offset by a corresponding increase in Margins from Off-system Sales below.
-

A $24 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense (Credit) below.

- A $9 million net decrease in margin for the Phase-In-Recovery Rider including associated amortizations.
- An $8 million decrease in Energy Efficiency/Peak Demand Reduction rider revenues. This decrease was offset by a decrease in Other Operation and Maintenance expenses below.

- Margins from Off-system Sales increased $31 million primarily due to lower 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.
- Transmission Revenues decreased $9 million due to the 2018 provisions for customer refunds due to Tax Reform. This decrease was offset in Income Tax Expense below.

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

- Other Operation and Maintenance expenses increased $212 million primarily due to the following:
- A $181 million increase in recoverable PJM expenses. This increase was offset within Gross Margins above.
- A $61 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in Retail Margins above.

These increases were partially offset by:

- A $55 million decrease in PJM expenses primarily related to the annual formula rate true-up that will be refunded in future periods.
- Depreciation and Amortization expenses increased $35 million primarily due to the following:
- A $13 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
- A $13 million increase in recoverable DIR depreciation expense. This increase was offset in Retail Margins above.
- A $4 million increase in amortization due to capitalized software.
- Taxes Other Than Income Taxes increased $17 million primarily due to the following:
- An $8 million increase in rider revenues recovering state excise taxes due to an increase in metered KWh. This increase was offset by a corresponding increase in Retail Margins above.
- An $8 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.
- Non-Service Cost Components of Net Periodic Cost decreased $8 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- Income Tax Expense (Credit) decreased $117 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and 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, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2018	2017	2018	2017
REVENUES				
Electricity, Transmission and Distribution	$772.6	$736.0	$2,294.8	$2,127.8
Sales to AEP Affiliates	3.3	4.6	17.9	19.4
Other Revenues	2.4	1.4	5.3	4.8
TOTAL REVENUES	778.3	742.0	2,318.0	2,152.0
EXPENSES				
Purchased Electricity for Resale	166.3	180.7	534.7	525.4
Purchased Electricity from AEP Affiliates	39.3	26.7	97.4	83.4
Amortization of Generation Deferrals	56.9	58.7	171.9	172.9
Other Operation	215.2	126.9	586.4	380.9
Maintenance	43.4	37.9	114.7	108.4
Depreciation and Amortization	70.4	57.3	200.3	165.7
Taxes Other Than Income Taxes	106.9	100.4	311.0	293.8
TOTAL EXPENSES	698.4	588.6	2,016.4	1,730.5
OPERATING INCOME	79.9	153.4	301.6	421.5
Other Income (Expense):				
Interest Income	0.8	0.7	2.6	4.0
Carrying Costs Income	0.2	0.5	1.5	3.0
Allowance for Equity Funds Used During Construction	2.0	0.9	7.8	4.1
Non-Service Cost Components of Net Periodic Benefit Cost	3.8	1.1	11.6	3.3
Interest Expense	(26.1)	(25.7)	(76.6)	(76.8)
INCOME BEFORE INCOME TAX EXPENSE (CREDIT)	60.6	130.9	248.5	359.1
Income Tax Expense (Credit)	(28.1)	48.3	11.4	128.0
NET INCOME	$88.7	$82.6	$237.1	$231.1

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

See Condensed Notes to

Condensed
Financial
Statements of
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page 141.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Net Income	$88.7	$82.6	$237.1	$231.1
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, 2018 and 2017, Respectively, and $(0.3) and $(0.4) for the Nine Months Ended September 30, 2018 and 2017, Respectively	(0.4)	(0.3)	(1.0)	(0.8)
TOTAL COMPREHENSIVE INCOME	$88.3	$82.3	$236.1	$230.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	$ 321.2	$ 838.8	$ 1,148.4	$ 1.9	$ 2,310.3
Common Stock Dividends			(337.5)		(337.5)
ASU 2018-02 Adoption				0.4	0.4
Net Income			237.1		237.1
Other Comprehensive Loss				(1.0)	(1.0)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2018	$ 321.2	$ 838.8	$ 1,048.0	$ 1.3	$ 2,209.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2018 and December 31, 2017
(in millions)
(Unaudited)

	September 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$3.5	$ 3.1
Restricted Cash for Securitized Funding	15.2	26.6
Accounts Receivable:		
Customers	116.9	67.8
Affiliated Companies	72.4	70.2
Accrued Unbilled Revenues	32.7	29.7
Miscellaneous	0.9	1.9
Allowance for Uncollectible Accounts	(1.4)	(0.6)
Total Accounts Receivable	221.5	169.0
Materials and Supplies	38.5	41.9
Renewable Energy Credits	23.0	25.0
Risk Management Assets	0.6	0.6
Regulatory Asset for Under-Recovered Fuel Costs	34.1	115.9
Prepayments and Other Current Assets	16.7	15.8
TOTAL CURRENT ASSETS	353.1	397.9
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	2,484.5	2,419.2
Distribution	4,825.6	4,626.4
Other Property, Plant and Equipment	547.5	495.9
Construction Work in Progress	475.7	410.1
Total Property, Plant and Equipment	8,333.3	7,951.6
Accumulated Depreciation and Amortization	2,230.6	2,184.8
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,102.7	5,766.8
OTHER NONCURRENT ASSETS		
Regulatory Assets	389.1	652.8
Securitized Assets	19.0	37.7
Long-term Risk Management Assets	0.1	—
Deferred Charges and Other Noncurrent Assets	254.6	406.5
TOTAL OTHER NONCURRENT ASSETS	662.8	1,097.0
TOTAL ASSETS	$7,118.6	$ 7,261.7

See
Condensed
Notes to
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Financial

Statements of Registrants beginning on page 141.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2018 and December 31, 2017
(dollars in millions)
(Unaudited)

	September 30, 2018	December 31, 2017
CURRENT LIABILITIES		
Advances from Affiliates	$ 242.9	$ 87.8
Accounts Payable:		
General	169.2	205.8
Affiliated Companies	95.3	118.2
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2018 and December 31, 2017 Amounts Include $47.7 and $47, Respectively, Related to Ohio Phase-in-Recovery Funding)	47.8	397.0
Risk Management Liabilities	5.4	6.4
Customer Deposits	77.5	69.2
Accrued Taxes	293.8	512.5
Other Current Liabilities	205.9	196.9
TOTAL CURRENT LIABILITIES	1,137.8	1,593.8
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (September 30, 2018 and December 31, 2017 Amounts Include $0 and $47.5, Respectively, Related to Ohio Phase-in-Recovery Funding)	1,668.5	1,322.3
Long-term Risk Management Liabilities	89.8	126.0
Deferred Income Taxes	742.8	762.9
Regulatory Liabilities and Deferred Investment Tax Credits	1,197.7	1,100.2
Deferred Credits and Other Noncurrent Liabilities	72.7	46.2
TOTAL NONCURRENT LIABILITIES	3,771.5	3,357.6
TOTAL LIABILITIES	4,909.3	4,951.4
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	1,048.0	1,148.4
Accumulated Other Comprehensive Income (Loss)	1.3	1.9
TOTAL COMMON SHAREHOLDER'S EQUITY	2,209.3	2,310.3
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 7,118.6	$ 7,261.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

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OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2018	2017
OPERATING ACTIVITIES		
Net Income	$237.1	$231.1
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	200.3	165.7
Amortization of Generation Deferrals	171.9	172.9
Deferred Income Taxes	(71.9)	117.5
Carrying Costs Income	(1.5)	(3.0)
Allowance for Equity Funds Used During Construction	(7.8)	(4.1)
Mark-to-Market of Risk Management Contracts	(37.1)	19.5
Pension Contributions to Qualified Plan Trust	—	(8.2)
Property Taxes	191.1	175.9
Provision for Refund – Global Settlement, Net	(5.5)	(93.3)
Change in Regulatory Assets	180.9	(82.2)
Change in Other Noncurrent Assets	0.8	(44.5)
Change in Other Noncurrent Liabilities	62.5	43.4
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	21.3	14.9
Materials and Supplies	(3.7)	(7.1)
Accounts Payable	(31.8)	(31.2)
Accrued Taxes, Net	(210.6)	(284.3)
Other Current Assets	9.1	(17.3)
Other Current Liabilities	(4.3)	(34.8)
Net Cash Flows from Operating Activities	700.8	330.9
INVESTING ACTIVITIES		
Construction Expenditures	(538.5)	(362.5)
Change in Advances to Affiliates, Net	—	24.2
Other Investing Activities	15.5	6.9
Net Cash Flows Used for Investing Activities	(523.0)	(331.4)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	392.8	—
Change in Advances from Affiliates, Net	155.1	167.6
Retirement of Long-term Debt – Nonaffiliated	(397.0)	(46.4)
Principal Payments for Capital Lease Obligations	(2.9)	(3.1)
Dividends Paid on Common Stock	(337.5)	(130.0)
Other Financing Activities	0.7	0.8
Net Cash Flows Used for Financing Activities	(188.8)	(11.1)
Net Decrease in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	(11.0)	(11.6)

Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	29.7	30.3
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$18.7	$18.7
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$67.3	$68.1
Net Cash Paid for Income Taxes	54.1	69.6
Noncash Acquisitions Under Capital Leases	3.0	3.6
Construction Expenditures Included in Current Liabilities as of September 30,	66.0	56.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

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,	
	2018	2017	2018	2017
	(in millions of KWhs)			
Retail:				
Residential	2,005	1,992	5,133	4,662
Commercial	1,456	1,488	4,008	3,926
Industrial	1,582	1,472	4,418	4,249
Miscellaneous	361	353	970	942
Total Retail	5,404	5,305	14,529	13,779
Wholesale	182	82	544	309
Total KWhs	5,586	5,387	15,073	14,088

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,	
	2018	2017	2018	2017
	(in degree days)			
Actual – Heating (a)	—	—	1,161	682
Normal – Heating (b)	1	1	1,082	1,104
Actual – Cooling (c)	1,433	1,313	2,352	2,001
Normal – Cooling (b)	1,396	1,395	2,063	2,064

(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 2018 Compared to Third Quarter of 2017
Reconciliation of Third Quarter of 2017 to Third Quarter of 2018
Net Income
(in millions)

Third Quarter of 2017	$46.2
Changes in Gross Margin:	
Retail Margins (a)	21.3
Off-system Sales	0.6
Transmission Revenues	1.0
Other Revenues	0.2
Total Change in Gross Margin	23.1
Changes in Expenses and Other:	
Other Operation and Maintenance	(18.9)
Depreciation and Amortization	(10.6)
Taxes Other Than Income Taxes	(1.0)
Other Income (Expense)	(0.2)
Non-Service Cost Components of Net Periodic Benefit Cost	1.2
Interest Expense	(3.2)
Total Change in Expenses and Other	(32.7)
Income Tax Expense	23.8
Third Quarter of 2018	$60.4

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

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

- Retail Margins increased $21 million primarily due to the following:
- A $20 million increase due to new rates implemented in March 2018, inclusive of a $9 million decrease due to the change in the corporate federal tax rate.
- An $11 million increase in revenue from rate riders. This increase was partially offset by corresponding increases to riders/trackers recognized in other expense items below.
- A $6 million increase in weather-related usage due to a 9% increase in cooling degree days.

These increases were partially offset by:

- A $6 million decrease due to lower weather-normalized margins.
- A $5 million decrease due to 2018 customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
- A $4 million decrease related to the System Reliability Rider (SRR) that ended in August 2017. This decrease was partially offset by a corresponding decrease recognized in other expense items below.

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

- Other Operation and Maintenance expenses increased $19 million primarily due the following:
  - A $13 million increase in transmission expenses primarily due to increased SPP transmission services.
  - A $4 million increase in Energy Efficiency program costs. This increase was offset by an increase from rate riders in Retail Margins above.
  - A $3 million increase in generation expenses including employee-related expenses.

  These increases were partially offset by:
  - A $3 million decrease in distribution expenses primarily due to the amortization of previously deferred vegetation management costs collected through the SRR. This decrease was partially offset by a corresponding decrease in Retail Margins above.
- Depreciation and Amortization expenses increased $11 million primarily due to a higher depreciable base and new rates implemented in March 2018.
- Income Tax Expense decreased $24 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

Reconciliation of Nine Months Ended September 30, 2017 to Nine Months Ended September 30, 2018
Net Income
(in millions)

Nine Months Ended September 30, 2017	$71.4
Changes in Gross Margin:	
Retail Margins (a)	55.3
Off-system Sales	0.8
Transmission Revenues	0.4
Other Revenues	0.2
Total Change in Gross Margin	56.7
Changes in Expenses and Other:	
Other Operation and Maintenance	(42.9)
Depreciation and Amortization	(22.7)
Taxes Other Than Income Taxes	(2.6)
Other Income (Expense)	(0.8)
Non-Service Cost Components of Net Periodic Benefit Cost	3.9
Interest Expense	(7.2)
Total Change in Expenses and Other	(72.3)
Income Tax Expense	34.0
Nine Months Ended September 30, 2018	$89.8

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

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

- Retail Margins increased $55 million primarily due to the following:
- A $37 million increase due to new rates implemented in March 2018, inclusive of a $19 million decrease due to the change in the corporate federal tax rate.
- A $30 million increase in weather-related usage due to a 70% increase in heating degree days and an 18% increase in cooling degree days.
- A $24 million increase in revenue from rate riders. This increase was partially offset by corresponding increases to riders/trackers recognized in other expense items below.

These increases were partially offset by:
- A $16 million decrease related to the SRR that ended in August 2017. This decrease was partially offset by a corresponding decrease recognized in other expense items below.
- A $15 million decrease due to 2018 customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
- A $4 million decrease due to lower weather-normalized margins.

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

- Other Operation and Maintenance expenses increased $43 million primarily due to the following:
  - A $37 million increase in transmission expenses primarily due to increased SPP transmission services.
  - A $12 million increase in Energy Efficiency program costs. This increase was offset by an increase from rate riders in Retail Margins above.
  - A $10 million increase due to the Wind Catcher Project.
  - A $4 million increase in generation expenses including employee-related expenses.

  These increases were partially offset by:
  - An $11 million decrease in distribution expenses primarily due to the amortization of previously deferred vegetation management costs collected through the SRR. This decrease was partially offset by a corresponding decrease in Retail Margins above.
  - An $11 million decrease due to a refund associated with SPP transmission expenses incurred in prior periods.
- Depreciation and Amortization expenses increased $23 million primarily due to a higher depreciable base and new rates implemented in March 2018.
- Non-Service Cost Components of Net Periodic Benefit Cost decreased $4 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- Interest Expense increased $7 million primarily due to the 2017 deferral of the debt component of carrying charges on environmental control costs for projects at Northeastern Plant, Unit 3 and Comanche Plant.
- Income Tax Expense decreased $34 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2018	2017	2018	2017
REVENUES				
Electric Generation, Transmission and Distribution	$479.1	$440.6	$1,209.5	$1,085.1
Sales to AEP Affiliates	1.1	1.1	3.7	3.2
Other Revenues	1.2	1.1	3.3	3.3
TOTAL REVENUES	481.4	442.8	1,216.5	1,091.6
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	104.4	77.9	211.5	115.8
Purchased Electricity for Resale	116.8	127.8	352.3	379.8
Other Operation	106.3	84.5	286.8	228.9
Maintenance	22.3	25.2	73.2	88.2
Depreciation and Amortization	42.3	31.7	120.5	97.8
Taxes Other Than Income Taxes	10.8	9.8	32.6	30.0
TOTAL EXPENSES	402.9	356.9	1,076.9	940.5
OPERATING INCOME	78.5	85.9	139.6	151.1
Other Income (Expense):				
Other Income (Expense)	(0.2)	—	(0.3)	0.5
Non-Service Cost Components of Net Periodic Benefit Cost	2.1	0.9	6.5	2.6
Interest Expense	(16.4)	(13.2)	(47.4)	(40.2)
INCOME BEFORE INCOME TAX EXPENSE	64.0	73.6	98.4	114.0
Income Tax Expense	3.6	27.4	8.6	42.6
NET INCOME	$60.4	$46.2	$89.8	$71.4

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

See Condensed Notes to Condensed Financial Statements of

Registrants
beginning on
page 141.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Net Income	$60.4	$46.2	$89.8	$71.4
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $(0.1) for the Three Months Ended September 30, 2018 and 2017, Respectively, and $(0.2) and $(0.3) for the Nine Months Ended September 30, 2018 and 2017, Respectively	(0.2)	(0.2)	(0.7)	(0.6)
TOTAL COMPREHENSIVE INCOME	$60.2	$46.0	$89.1	$70.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

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PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	$ 157.2	$ 364.0	$ 691.5	$ 2.6	$ 1,215.3
Common Stock Dividends			(37.5)		(37.5)
ASU 2018-02 Adoption				0.5	0.5
Net Income			89.8		89.8
Other Comprehensive Loss				(0.7)	(0.7)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2018	$ 157.2	$ 364.0	$ 743.8	$ 2.4	$ 1,267.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2018 and December 31, 2017
(in millions)
(Unaudited)

	September 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1.9	$ 1.6
Accounts Receivable:		
Customers	28.8	32.5
Affiliated Companies	39.8	32.9
Miscellaneous	4.4	4.1
Allowance for Uncollectible Accounts	(0.2)	(0.1)
Total Accounts Receivable	72.8	69.4
Fuel	12.6	12.5
Materials and Supplies	43.4	42.0
Risk Management Assets	18.5	6.4
Accrued Tax Benefits	12.5	28.1
Regulatory Asset for Under-Recovered Fuel Costs	—	36.7
Prepayments and Other Current Assets	8.1	8.6
TOTAL CURRENT ASSETS	169.8	205.3
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,576.3	1,577.2
Transmission	881.5	858.8
Distribution	2,543.1	2,445.1
Other Property, Plant and Equipment	308.3	287.4
Construction Work in Progress	85.7	111.3
Total Property, Plant and Equipment	5,394.9	5,279.8
Accumulated Depreciation and Amortization	1,461.2	1,393.6
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	3,933.7	3,886.2
OTHER NONCURRENT ASSETS		
Regulatory Assets	352.1	368.1
Employee Benefits and Pension Assets	41.3	40.0
Deferred Charges and Other Noncurrent Assets	16.6	8.7
TOTAL OTHER NONCURRENT ASSETS	410.0	416.8
TOTAL ASSETS	$ 4,513.5	$ 4,508.3

See Condensed Notes to Condensed Financial Statements

of
Registrants
beginning
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141.

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PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2018 and December 31, 2017
(Unaudited)

	September 30, 2018	December 31, 2017
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$22.0	$ 149.6
Accounts Payable:		
General	113.0	102.4
Affiliated Companies	42.2	48.0
Long-term Debt Due Within One Year – Nonaffiliated	0.5	0.5
Risk Management Liabilities	0.6	—
Customer Deposits	56.1	54.1
Accrued Taxes	40.5	22.6
Accrued Interest	18.9	14.1
Regulatory Liability for Over-Recovered Fuel Costs	36.0	—
Other Current Liabilities	56.5	44.7
TOTAL CURRENT LIABILITIES	386.3	436.0
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,286.4	1,286.0
Deferred Income Taxes	636.6	642.0
Regulatory Liabilities and Deferred Investment Tax Credits	850.3	853.5
Asset Retirement Obligations	54.8	53.0
Deferred Credits and Other Noncurrent Liabilities	31.7	22.5
TOTAL NONCURRENT LIABILITIES	2,859.8	2,857.0
TOTAL LIABILITIES	3,246.1	3,293.0
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	743.8	691.5
Accumulated Other Comprehensive Income (Loss)	2.4	2.6
TOTAL COMMON SHAREHOLDER'S EQUITY	1,267.4	1,215.3
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$4,513.5	$ 4,508.3

See
Condensed

Notes to Condensed Financial Statements of Registrants beginning on page 141.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2018	2017
OPERATING ACTIVITIES		
Net Income	$ 89.8	$ 71.4
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	120.5	97.8
Deferred Income Taxes	(13.4)	93.7
Allowance for Equity Funds Used During Construction	0.3	(0.4)
Mark-to-Market of Risk Management Contracts	(11.5)	(3.9)
Pension Contributions to Qualified Plan Trust	—	(5.3)
Property Taxes	(9.6)	(9.4)
Deferred Fuel Over/Under-Recovery, Net	73.3	(5.6)
Provision for Refund, Net	3.7	(39.4)
Change in Other Noncurrent Assets	6.9	(19.8)
Change in Other Noncurrent Liabilities	10.9	(1.4)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(3.4)	5.8
Fuel, Materials and Supplies	(1.5)	13.5
Accounts Payable	6.9	(18.5)
Accrued Taxes, Net	38.4	20.1
Other Current Assets	0.3	(8.2)
Other Current Liabilities	15.1	1.5
Net Cash Flows from Operating Activities	326.7	191.9
INVESTING ACTIVITIES		
Construction Expenditures	(162.8)	(203.1)
Other Investing Activities	3.9	1.5
Net Cash Flows Used for Investing Activities	(158.9)	(201.6)
FINANCING ACTIVITIES		
	(127.6)	66.0

Change in Advances from Affiliates, Net		
Retirement of Long-term Debt – Nonaffiliated	(0.3)	(0.3)
Principal Payments for Capital Lease Obligations	(2.5)	(3.2)
Dividends Paid on Common Stock	(37.5)	(52.5)
Other Financing Activities	0.4	0.3
Net Cash Flows from (Used for) Financing Activities	(167.5)	10.3
Net Increase in Cash and Cash Equivalents	0.3	0.6
Cash and Cash Equivalents at Beginning of Period	1.6	1.5
Cash and Cash Equivalents at End of Period	$ 1.9	$ 2.1
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 42.0	$ 40.9
Net Cash Paid (Received) for Income Taxes	1.6	(46.6)
Noncash Acquisitions Under Capital Leases	2.3	1.0
Construction Expenditures Included in Current Liabilities as of September 30,	24.3	15.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

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,	
	2018	2017	2018	2017
	(in millions of KWhs)			
Retail:				
Residential	1,992	1,887	5,156	4,547
Commercial	1,701	1,677	4,619	4,466
Industrial	1,340	1,339	3,962	3,895
Miscellaneous	19	19	59	60
Total Retail	5,052	4,922	13,796	12,968
Wholesale	1,881	2,105	5,352	6,286
Total KWhs	6,933	7,027	19,148	19,254

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,	
	2018	2017	2018	2017
	(in degree days)			
Actual – Heating (a)	—	—	784	394
Normal – Heating (b)	1	1	733	747
Actual – Cooling (c)	1,453	1,248	2,408	1,999
Normal – Cooling (b)	1,408	1,414	2,179	2,185

(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 2018 Compared to Third Quarter of 2017
Reconciliation of Third Quarter of 2017 to Third Quarter of 2018
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Third Quarter of 2017	$73.1
Changes in Gross Margin:	
Retail Margins (a)	11.0
Transmission Revenues	5.3
Other Revenues	0.2
Total Change in Gross Margin	16.5
Changes in Expenses and Other:	
Other Operation and Maintenance	(18.9)
Depreciation and Amortization	(4.7)
Taxes Other Than Income Taxes	(1.8)
Interest Income	0.4
Allowance for Equity Funds Used During Construction	0.2
Non-Service Cost Components of Net Periodic Benefit Cost	1.3
Interest Expense	(0.8)
Total Change in Expenses and Other	(24.3)
Income Tax Expense	12.9
Equity Earnings (Loss) of Unconsolidated Subsidiary	0.4
Net Income Attributable to Noncontrolling Interest	9.6
Third Quarter of 2018	$88.2

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

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

- Retail Margins increased $11 million primarily due to the following:
- An $18 million increase primarily due to rider and base rate revenue increases in Texas and Louisiana.
- A $14 million increase in weather-related usage primarily due to a 16% increase in cooling degree days.

These increases were partially offset by:
- A $15 million decrease due to lower weather-normalized margins.
- A $9 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
- Transmission Revenues increased $5 million primarily due to an increase in SPP transmission investments.

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

- Other Operation and Maintenance expenses increased $19 million primarily due to the following:
- A $4 million increase due to employee-related expenses.
- A $4 million increase in SPP transmission services.

- A $3 million increase due to the Wind Catcher Project.
- A $3 million increase in Energy Efficiency program costs. This increase was offset by an increase from rate riders in Retail Margins above.
- A $2 million increase in distribution expenses.
- Depreciation and Amortization expenses increased $5 million primarily due to a higher depreciable base.

- Income Tax Expense decreased $13 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.
- Net Income Attributable to Noncontrolling Interest decreased $10 million primarily due to income tax benefits attributable to SWEPCo's noncontrolling interest in Sabine. This decrease was offset by an increase in Income Tax Expense above.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017
Reconciliation of Nine Months Ended September 30, 2017 to Nine
Months Ended September 30, 2018
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Nine Months Ended September 30, 2017	$113.9
Changes in Gross Margin:	
Retail Margins (a)	49.4
Off-system Sales	(1.6)
Transmission Revenues	2.8
Total Change in Gross Margin	50.6
Changes in Expenses and Other:	
Other Operation and Maintenance	(52.8)
Depreciation and Amortization	(17.8)
Taxes Other Than Income Taxes	(3.7)
Interest Income	1.5
Allowance for Equity Funds Used During Construction	2.6
Non-Service Cost Components of Net Periodic Benefit Cost	4.1
Interest Expense	(3.1)
Total Change in Expenses and Other	(69.2)
Income Tax Expense	27.3
Equity Earnings (Loss) of Unconsolidated Subsidiary	6.5
Net Income Attributable to Noncontrolling Interest	8.5
Nine Months Ended September 30, 2018	$137.6

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

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

- Retail Margins increased $49 million primarily due to the following:
  - A $57 million increase primarily due to rider and base rate revenue increases in Texas, Louisiana and Arkansas.
  - A $48 million increase in weather-related usage primarily due to a 99% increase in heating degree days and a 20% increase in cooling degree days.

  These increases were partially offset by:
  - A $36 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
  - A $26 million decrease due to lower weather-normalized margins, primarily due to wholesale customer load loss from contracts that expired at the end of 2017.
- Transmission Revenues increased $3 million primarily due to a $14 million increase from continued SPP transmission investments, partially offset by an $11 million decrease from a 2018 provision for refund related to revenues recorded in prior periods on certain transmission assets that management believes should not have been included in the SPP formula rate.

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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 $53 million primarily due to the following:
- A $25 million increase due to the Wind Catcher Project.
- A $21 million increase in SPP transmission services.
- An $8 million increase in customer expenses primarily due to the following:
- A $3 million increase in Energy Efficiency program costs. This increase was offset by an increase from rate riders in Retail Margins above.
- A $3 million increase in customer assistance.
- A $5 million increase due to employee-related expenses.

These increases were partially offset by:

- An $8 million decrease due to a refund associated with transmission expenses incurred in prior periods.
- Depreciation and Amortization expenses increased $18 million primarily due to a higher depreciable base and higher depreciation rates from the 2017 Texas base rate case order.
- Taxes Other Than Income Taxes increased $4 million primarily due to increased franchise and property taxes.
- Non-Service Cost Components of Net Periodic Benefit Cost decreased $4 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- Interest Expense increased $3 million primarily due to other interest expense accruals for refunds and true-ups in 2018 and interest expense credits in 2017 on Welsh Plant and Flint Creek Plant environmental project deferrals.
- Income Tax Expense decreased $27 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.
- Equity Earnings (Loss) of Unconsolidated Subsidiary increased $7 million primarily due to a prior period income tax adjustment recognized in 2017.
- Net Income Attributable to Noncontrolling Interest decreased $9 million primarily due to income tax benefits attributable to SWEPCo’s noncontrolling interest in Sabine. This decrease was offset by an increase in Income Tax Expense above.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2018	2017	2018	2017
REVENUES				
Electric Generation, Transmission and Distribution	$526.0	$509.5	$1,390.4	$1,321.8
Sales to AEP Affiliates	8.7	7.7	20.2	20.4
Other Revenues	0.6	0.4	1.2	1.4
TOTAL REVENUES	535.3	517.6	1,411.8	1,343.6
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	152.1	147.5	393.4	389.8
Purchased Electricity for Resale	36.6	40.0	132.7	118.7
Other Operation	99.1	81.2	292.0	234.9
Maintenance	33.6	32.6	102.2	106.5
Depreciation and Amortization	59.9	55.2	175.9	158.1
Taxes Other Than Income Taxes	26.9	25.1	76.4	72.7
TOTAL EXPENSES	408.2	381.6	1,172.6	1,080.7
OPERATING INCOME	127.1	136.0	239.2	262.9
Other Income (Expense):				
Interest Income	1.1	0.7	3.5	2.0
Allowance for Equity Funds Used During Construction	0.6	0.4	3.8	1.2
Non-Service Cost Components of Net Periodic Benefit Cost	2.3	1.0	6.9	2.8
Interest Expense	(32.7)	(31.9)	(95.8)	(92.7)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS (LOSS)	98.4	106.2	157.6	176.2
Income Tax Expense	9.6	22.5	17.9	45.2
Equity Earnings (Loss) of Unconsolidated Subsidiary	0.8	0.4	2.0	(4.5)
NET INCOME	89.6	84.1	141.7	126.5
Net Income Attributable to Noncontrolling Interest	1.4	11.0	4.1	12.6
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$88.2	$73.1	$137.6	$113.9

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Net Income	$89.6	$84.1	$141.7	$126.5
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.8 and $0.2 for the Three Months Ended September 30, 2018 and 2017, Respectively, and $1 and $0.6 for the Nine Months Ended September 30, 2018 and 2017, Respectively	2.7	0.4	3.6	1.1
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended September 30, 2018 and 2017, Respectively, and $(0.3) and $(0.3) for the Nine Months Ended September 30, 2018 and 2017, Respectively	(0.3)	(0.2)	(1.0)	(0.5)
TOTAL OTHER COMPREHENSIVE INCOME	2.4	0.2	2.6	0.6
TOTAL COMPREHENSIVE INCOME	92.0	84.3	144.3	127.1
Total Comprehensive Income Attributable to Noncontrolling Interest	1.4	11.0	4.1	12.6
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$90.6	$73.3	$140.2	$114.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2018 and 2017
(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, 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
TOTAL EQUITY – DECEMBER 31, 2017	$135.7	$676.6	$1,426.6	$ (4.0)	$ (0.4)	$2,234.5
Common Stock Dividends			(60.0)			(60.0)
Common Stock Dividends – Nonaffiliated					(3.2)	(3.2)
ASU 2018-02 Adoption			(0.4)	(0.9)		(1.3)
Net Income			137.6		4.1	141.7
Other Comprehensive Income				2.6		2.6
TOTAL EQUITY – SEPTEMBER 30, 2018	$135.7	$676.6	$1,503.8	$ (2.3)	$ 0.5	$2,314.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2018 and December 31, 2017
(in millions)
(Unaudited)

	September 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2.5	$ 1.6
Advances to Affiliates	518.6	2.0
Accounts Receivable:		
Customers	29.1	70.9
Affiliated Companies	32.8	30.2
Miscellaneous	20.9	25.8
Allowance for Uncollectible Accounts	(0.9)	(1.3)
Total Accounts Receivable	81.9	125.6
Fuel (September 30, 2018 and December 31, 2017 Amounts Include $33.4 and $41.5, Respectively, Related to Sabine)	117.5	123.6
Materials and Supplies	69.0	67.9
Risk Management Assets	6.5	6.4
Regulatory Asset for Under-Recovered Fuel Costs	14.5	14.1
Prepayments and Other Current Assets	32.0	39.2
TOTAL CURRENT ASSETS	842.5	380.4
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,655.6	4,624.9
Transmission	1,812.0	1,679.8
Distribution	2,146.4	2,095.8
Other Property, Plant and Equipment (September 30, 2018 and December 31, 2017 Amounts Include $269.6 and $266.7, Respectively, Related to Sabine)	744.4	684.1
Construction Work in Progress	234.5	233.2
Total Property, Plant and Equipment	9,592.9	9,317.8
Accumulated Depreciation and Amortization (September 30, 2018 and December 31, 2017 Amounts Include $174.7 and $165.9, Respectively, Related to Sabine)	2,798.9	2,685.8
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,794.0	6,632.0
OTHER NONCURRENT ASSETS		
Regulatory Assets	217.8	220.6
Deferred Charges and Other Noncurrent Assets	133.1	109.9
TOTAL OTHER NONCURRENT ASSETS	350.9	330.5
TOTAL ASSETS	$ 7,987.4	$ 7,342.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2018 and December 31, 2017
(Unaudited)

	September 30, 2018	December 31, 2017
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$—	$ 118.7
Accounts Payable:		
General	117.6	160.4
Affiliated Companies	41.3	63.7
Short-term Debt – Nonaffiliated	19.4	22.0
Long-term Debt Due Within One Year – Nonaffiliated	457.2	3.7
Risk Management Liabilities	0.2	0.2
Customer Deposits	62.7	62.1
Accrued Taxes	75.2	39.0
Accrued Interest	27.5	38.9
Obligations Under Capital Leases	10.8	11.2
Other Current Liabilities	101.6	78.7
TOTAL CURRENT LIABILITIES	913.5	598.6
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,615.5	2,438.2
Long-term Risk Management Liabilities	2.6	—
Deferred Income Taxes	932.9	917.7
Regulatory Liabilities and Deferred Investment Tax Credits	896.7	896.4
Asset Retirement Obligations	179.3	160.3
Employee Benefits and Pension Obligations	19.3	19.5
Obligations Under Capital Leases	52.8	57.8
Deferred Credits and Other Noncurrent Liabilities	60.5	19.9
TOTAL NONCURRENT LIABILITIES	4,759.6	4,509.8
TOTAL LIABILITIES	5,673.1	5,108.4
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	1,503.8	1,426.6
Accumulated Other Comprehensive Income (Loss)	(2.3)	(4.0)
TOTAL COMMON SHAREHOLDER’S EQUITY	2,313.8	2,234.9

Noncontrolling Interest	0.5	(0.4)
TOTAL EQUITY	2,314.3	2,234.5
TOTAL LIABILITIES AND EQUITY	$7,987.4	$ 7,342.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

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SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2018 and 2017
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2018	2017
OPERATING ACTIVITIES		
Net Income	$ 141.7	$ 126.5
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	175.9	158.1
Deferred Income Taxes	2.0	79.8
Allowance for Equity Funds Used During Construction	(3.8)	(1.2)
Mark-to-Market of Risk Management Contracts	2.5	(12.5)
Pension Contributions to Qualified Plan Trust	—	(8.9)
Property Taxes	(15.8)	(15.4)
Deferred Fuel Over/Under-Recovery, Net	4.4	2.4
Change in Other Noncurrent Assets	(8.9)	(2.9)
Change in Other Noncurrent Liabilities	52.1	(5.2)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	44.3	12.1
Fuel, Materials and Supplies	5.0	13.6
Accounts Payable	(29.9)	(25.7)
Accrued Taxes, Net	38.4	69.1
Accrued Interest	(11.4)	(20.0)
Other Current Assets	3.2	0.7
Other Current Liabilities	15.6	(14.6)
Net Cash Flows from Operating Activities	415.3	355.9
INVESTING ACTIVITIES		
Construction Expenditures	(336.6)	(265.3)
Change in Advances to Affiliates, Net	(516.6)	167.8
Other Investing Activities	1.2	3.1
Net Cash Flows Used for Investing Activities	(852.0)	(94.4)

FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	1,015.4	114.6
Change in Short-term Debt – Nonaffiliated	(2.6)	14.3
Change in Advances from Affiliates, Net	(118.7)	48.3
Retirement of Long-term Debt – Nonaffiliated	(385.3)	(353.6)
Principal Payments for Capital Lease Obligations	(8.5)	(8.4)
Dividends Paid on Common Stock	(60.0)	(82.5)
Dividends Paid on Common Stock – Nonaffiliated	(3.2)	(2.7)
Other Financing Activities	0.5	0.4
Net Cash Flows from (Used for) Financing Activities	437.6	(269.6)
Net Increase (Decrease) in Cash and Cash Equivalents	0.9	(8.1)
Cash and Cash Equivalents at Beginning of Period	1.6	10.3
Cash and Cash Equivalents at End of Period	$ 2.5	$ 2.2
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 102.5	$ 109.4
Net Cash Paid (Received) for Income Taxes	12.9	(70.5)
Noncash Acquisitions Under Capital Leases	3.2	2.8
Construction Expenditures Included in Current Liabilities as of September 30,	37.0	40.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 141.

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, 2018 is not necessarily indicative of results that may be expected for the year ending December 31, 2018. The condensed financial statements are unaudited and should be read in conjunction with the audited 2017 financial statements and notes thereto, which are included in the Registrants' Annual Reports on Form 10-K as filed with the SEC on February 22, 2018.

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,			
	2018		2017	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$577.6		$544.7	
Weighted Average Number of Basic Shares Outstanding	493.0	$ 1.17	491.8	$ 1.11
Weighted Average Dilutive Effect of Stock-Based Awards	0.9	—	1.2	(0.01)
Weighted Average Number of Diluted Shares Outstanding	493.9	$ 1.17	493.0	$ 1.10

	Nine Months Ended September 30,			
	2018		2017	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$1,560.4		$1,511.9	
Weighted Average Number of Basic Shares Outstanding	492.6	$3.17	491.8	$ 3.07
Weighted Average Dilutive Effect of Stock-Based Awards	0.9	(0.01)	0.6	—
Weighted Average Number of Diluted Shares Outstanding	493.5	$3.16	492.4	$ 3.07

There were no antidilutive shares outstanding as of September 30, 2018 and 2017.

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.

Revisions to Previously Issued Financial Statements (Applies to only AEPTCo)

In the second quarter of 2018, management identified certain transmission assets that it believes should not have been included in AEPTCo's SPP transmission formula rates. As a result, AEPTCo recorded a pretax out of period correction of an error of approximately $17 million related to revenue recorded from 2013 through March 31, 2018 in the second quarter of 2018. Subsequent to filing the second quarter 2018 Form 10-Q, AEPTCo identified an additional error in its previously issued financial statements. This error resulted from the improper capitalization of AFUDC and subsequent revenue recorded on the AFUDC. The impact of this misstatement reduced AEPTCo's pretax income by approximately $7 million on a cumulative basis for the period 2011 through June 30, 2018.

Management assessed the materiality of the misstatements on all previously issued AEPTCo financial statements in accordance with SEC Staff Accounting Bulletin (SAB) No. 99, Materiality, codified in ASC 250, Presentation of Financial Statements and concluded these misstatements were not material, individually or in the aggregate, to any prior annual or interim period. In accordance with ASC 250 (SAB No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements), management revised the prior period AEPTCo financial statements included in this report to reflect the impact of correcting the immaterial misstatements described above. In addition, management will revise the historical 2017, March 31, 2018 and June 30, 2018 periods presented in AEPTCo's previously issued financial statements in future SEC Form 10-Q and Form 10-K filings to reflect the impact of the misstatements. The $(18) million adjustment to pretax income for the nine months ended September 30, 2017 includes adjustments of $(12) million relating to 2016 and earlier periods. The effect of recording this adjustment of $(12) million in 2017 is not material to AEPTCo's financial statements for 2017 or any earlier period.

AEPTCo has also corrected other previously recorded immaterial out of period adjustments. The impact of these additional adjustments did not impact net income in any period.

Management also assessed the materiality of the AEPTCo's misstatements discussed above on all previously issued and the current year AEP financial statements in accordance with ASC 250, and concluded these misstatements were not material, individually or in the aggregate, to any prior and current interim and annual period financial statements. As a result, AEP recorded the correction in the third quarter of 2018.

Statements of Income

The table below reflects the effects of correcting the immaterial errors described above on AEPTCo's statements of income for the three and nine months ended September 30, 2017:

	Three Months Ended September 30, 2017			Nine Months Ended September 30, 2017		
	As Reported	Adjustments	As Adjusted	As Reported	Adjustments	As Adjusted
	(in millions)			(in millions)		
TOTAL REVENUES	$167.3	$ (1.7)	$ 165.6	$549.4	$ (14.6)	$ 534.8
EXPENSES						
Depreciation and Amortization	24.8	(0.2)	24.6	70.9	(1.2)	69.7
TOTAL EXPENSES	72.2	(0.2)	72.0	198.5	(1.2)	197.3
OPERATING INCOME	95.1	(1.5)	93.6	350.9	(13.4)	337.5
Other Income (Expense):						

Allowance for Equity Funds Used During Construction	11.7	(0.3)	11.4	36.0	(3.0)	33.0
Interest Expense	(16.9)	(0.2)	(17.1)	(48.6)	(1.8)	(50.4)
INCOME BEFORE INCOME TAX EXPENSE	90.1	(2.0)	88.1	338.8	(18.2)	320.6
Income Tax Expense	30.2	(0.7)	29.5	114.5	(6.3)	108.2
NET INCOME	$59.9	$ (1.3)	$ 58.6	$224.3	$ (11.9)	$ 212.4

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Balance Sheet

The table below reflects the effects of correcting the immaterial errors described above on AEPTCo's Balance Sheet as of December 31, 2017:

	December 31, 2017		
	As Reported	Adjustment	As Adjusted
CURRENT ASSETS	(in millions)		
Accounts Receivable:			
Customers	$19.1	$ (4.1)	$15.0
Total Accounts Receivable	113.6	(4.1)	109.5
Accrued Tax Benefits	46.6	2.8	49.4
TOTAL CURRENT ASSETS	327.7	(1.3)	326.4
TRANSMISSION PROPERTY			
Transmission Property	5,336.1	(16.4)	5,319.7
Other Property, Plant and Equipment	131.4	(4.6)	126.8
Construction Work in Progress	1,312.7	11.3	1,324.0
Total Transmission Property	6,780.2	(9.7)	6,770.5
Accumulated Depreciation and Amortization	170.4	(17.8)	152.6
TOTAL TRANSMISSION PROPERTY – NET	6,609.8	8.1	6,617.9
OTHER NONCURRENT ASSETS			
Deferred Property Taxes	117.8	7.2	125.0
TOTAL OTHER NONCURRENT ASSETS	130.6	7.2	137.8
TOTAL ASSETS	$7,068.1	$ 14.0	$7,082.1
CURRENT LIABILITIES			
Accounts Payable:			
General	$473.2	$11.3	$484.5
Affiliated Companies	52.9	13.2	66.1
Accrued Taxes	225.4	6.1	231.5
TOTAL CURRENT LIABILITIES	836.3	30.6	866.9
NONCURRENT LIABILITIES			
Deferred Income Taxes	601.7	(1.3)	600.4
Regulatory Liabilities	493.7	0.1	493.8
TOTAL NONCURRENT LIABILITIES	3,626.5	(1.2)	3,625.3
TOTAL LIABILITIES	4,462.8	29.4	4,492.2
MEMBER'S EQUITY			
Retained Earnings	788.7	(15.4)	773.3
TOTAL MEMBER'S EQUITY	2,605.3	(15.4)	2,589.9
TOTAL LIABILITIES AND MEMBER'S EQUITY	$7,068.1	$14.0	$7,082.1

Statement of Cash Flows

The table below reflects the effects of correcting the immaterial errors described above on AEPTCo's statement of cash flows for the nine months ended September 30, 2017:

	Nine Months Ended September 30, 2017		
	As Reported	Adjustments	As Adjusted
	(in millions)		
OPERATING ACTIVITIES			
Net Income	$224.3	$ (11.9)	$ 212.4
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	70.9	(1.2)	69.7
Deferred Income Taxes	193.0	(1.1)	191.9
Allowance for Equity Funds Used During Construction	(36.0)	3.0	(33.0)
Change in Other Noncurrent Assets	7.6	1.0	8.6
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(44.4)	3.6	(40.8)
Accounts Payable	8.6	11.8	20.4
Accrued Taxes, Net	(66.0)	(5.2)	(71.2)
Net Cash Flows from Operating Activities	444.9	—	444.9
INVESTING ACTIVITIES			
Net Cash Flows Used for Investing Activities	(1,277.4)	—	(1,277.4)
FINANCING ACTIVITIES			
Net Cash Flows from Financing Activities	832.5	—	832.5
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	$ 1.8	$ 30.4
Construction Expenditures Included in Current Liabilities as of September 30,	239.0	9.9	248.9

Statement of Changes in Member's Equity

The statement of changes in AEPTCo's member's equity reflects the adjustments to Net Income of $(1) million and $(12) million for the three and nine months ended September 30, 2017 as shown in the table under Net Income above. The statement of changes in member's equity also reflects the adjustments to Retained Earnings of $(15) million as of December 31, 2017 as shown in the table under Balance Sheet above.

Restricted Cash (Applies to AEP, AEP Texas, APCo and OPCo)

Restricted Cash primarily includes funds held by trustees for the payment of securitization bonds.

Reconciliation of Cash, Cash Equivalents and Restricted Cash

The following tables provide a reconciliation of Cash, Cash Equivalents and Restricted Cash reported on the balance sheets that sum to the total of the same amounts shown on the statements of cash flows:

	September 30, 2018			
	AEP	AEP Texas	APCo	OPCo
	(in millions)			
Cash and Cash Equivalents	$788.3	$0.1	$2.2	$3.5
Restricted Cash	149.2	124.2	9.9	15.2
Total Cash, Cash Equivalents and Restricted Cash	$937.5	$124.3	$12.1	$18.7

	December 31, 2017			
	AEP	AEP Texas	APCo	OPCo
	(in millions)			
Cash and Cash Equivalents	$214.6	$2.0	$2.9	$3.1
Restricted Cash	198.0	155.2	16.3	26.6
Total Cash, Cash Equivalents and Restricted Cash	$412.6	$157.2	$19.2	$29.7

2. NEW ACCOUNTING PRONOUNCEMENTS

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

During FASB's standard-setting process and upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to the Registrants' business. The following 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 changing 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.

Management adopted ASU 2014-09 effective January 1, 2018, by means of the modified retrospective approach for all contracts. The adoption of ASU 2014-09 did not have a material impact on results of operations, financial position or cash flows. In that regard, the application of the new standard did not cause any significant differences in any individual financial statement line items had those line items been presented in accordance with the guidance that was in effect prior to the adoption of the new standard. Further, given the lack of material impact to the financial statements, the adoption of the new standard did not give rise to any material changes in the Registrants' previously established accounting policies for revenue. See Note 14 - Revenue from Contracts with Customers for additional disclosures required by the new standard.

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

In January 2016, the FASB issued ASU 2016-01 revising 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. For equity investments that do not have a readily determinable fair value, entities are permitted to elect a practicality exception and measure the investment at cost, less impairment, plus or minus observable price changes. 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.

Management adopted ASU 2016-01 effective January 1, 2018, by means of a cumulative-effect adjustment to the balance sheet. The adoption of ASU 2016-01 resulted in an immaterial impact on results of operations and financial position of AEP, and no impact to results of operations or financial position of the Registrant Subsidiaries. There was no impact on cash flows of the Registrants.

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 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. In July 2018, the FASB issued ASU 2018-11 “Leases (Topic 842): Targeted Improvements”, which provides an optional expedient to adopt the new lease requirements through a cumulative-effect adjustment in the period of adoption. Management plans to apply the new optional transition guidance.

New leasing standard implementation activities to date include the identification of the lease population within the AEP System as well as the sampling of representative lease contracts to analyze accounting treatment under the new accounting guidance. Based upon the completed assessments, management also prepared a gap analysis to outline new disclosure compliance requirements. A lease system was selected after reviewing multiple system options. System implementation activities of core functionality continue in the fourth quarter of 2018. Implementation of reporting functionality designed to meet new disclosure requirements is ongoing.

Management plans to elect certain of the optional 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.
Existing and expired land easements not previously accounted for as leases	Elect optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current leases guidance in Topic 840.

Evaluation of new lease contracts will continue through the fourth quarter. Management expects the new standard to impact financial position and, at this time, cannot estimate the impact. Management does not expect any impact to results of operations or cash flows. Management plans to adopt ASU 2016-02 and its related guidance effective January 1, 2019.

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 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 on 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.

Management adopted ASU 2017-07 effective January 1, 2018. Presentation of the non-service components on a separate line outside of operating income was applied on a retrospective basis, using the amounts disclosed in the benefit plan note for the estimation basis as a practical expedient. Capitalization of only the service cost component was applied on a prospective basis.

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. Among other things, ASU 2017-12: (a) expands the types of transactions eligible for hedge accounting, (b) eliminates the separate measurement and presentation of hedge ineffectiveness, (c) simplifies the requirements around the assessment of hedge effectiveness, (d) provides companies more time to finalize hedge documentation and (e) enhances presentation and disclosure requirements.

Management early adopted ASU 2017-12 in the second quarter of 2018, effective January 1, 2018, by means of a modified retrospective approach. The adoption of ASU 2017-12 resulted in an immaterial impact on results of operations and financial position of AEP, and no impact to results of operations or financial position of the Registrant Subsidiaries. There was no impact on cash flows of the Registrants. Further, given the lack of material impact to the financial statements, the adoption of the new standard did not give rise to any material changes in the Registrants' previously established accounting policies for derivatives and hedging.

ASU 2018-02 "Reclassification of Certain Tax Effects from AOCI" (ASU 2018-02)

In February 2018, the FASB issued ASU 2018-02 allowing a reclassification from AOCI to Retained Earnings for stranded tax effects resulting from Tax Reform. The accounting guidance for "Income Taxes" requires deferred tax assets and liabilities to be adjusted for the effect of a change in tax law or rates with the effect included in income from continuing operations in the reporting period that includes the enactment date of the tax change. This guidance is applicable for the tax effects of items in AOCI that were originally recognized in Other Comprehensive Income. As a result and absent the new guidance in this ASU, the tax effects of items within AOCI would not reflect the newly enacted corporate tax rate.

Management adopted ASU 2018-02 effective January 1, 2018, electing to reclassify the effects of the change in the federal corporate tax rate due to Tax Reform from AOCI to Retained Earnings. A portion of the reclassification was recorded to Regulatory Liabilities to adjust the tax effects of certain interest rate hedges in AEP's regulated jurisdictions that were previously deferred as a part of the accounting for Tax Reform. There were no other effects from Tax Reform that impacted AOCI. Management applied the new guidance at the beginning of the period of adoption. The adoption of the new standard did not have a material impact on the statement of financial position and did not impact results of operations or cash flows.

ASU 2018-15 “Internal-Use Software: Customer’s Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract” (ASU 2018-15)

In August 2018, the FASB issued ASU 2018-15 aligning the requirements for capitalizing implementation costs incurred in a cloud computing arrangement (hosting arrangement) that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The new standard requires an entity (customer) in a hosting arrangement that is a service contract to follow the accounting guidance for “Internal-Use Software” to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. Capitalized implementation costs of a hosting arrangement that is a service contract should be amortized over the term of the hosting arrangement. The expense related to the capitalized implementation costs should be presented in the same line item in the statement of income as the fees associated with the hosting element (service) of the arrangement. Payments for capitalized implementation costs in the statement of cash flows should be classified in the same manner as payments made for fees associated with the hosting element. Capitalized implementation costs in the statement of financial position should be presented in the same line item that a prepayment for the fees of the associated hosting arrangement would be presented.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2019, with early adoption permitted. The amendments may be applied either retrospectively or prospectively to applicable implementation costs incurred after the date of adoption. Management is analyzing the impact of this new standard and at this time, cannot estimate the impact of adoption on results of operations, financial position or cash flows. Management plans to adopt ASU 2018-15 prospectively, effective January 1, 2020.

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 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, 2018 and 2017. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 7 - Benefit Plans for additional details.

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2018

	Cash Flow Hedges			
	Commodity	Interest Rate	Pension and OPEB	Total
	(in millions)			
Balance in AOCI as of June 30, 2018	$(30.4)	$(15.3)	$(49.1)	$(94.8)
Change in Fair Value Recognized in AOCI	12.2	2.3	—	14.5
Amount of (Gain) Loss Reclassified from AOCI				
Generation & Marketing Revenues (a)	(0.1)	—	—	(0.1)
Purchased Electricity for Resale (a)	(5.8)	—	—	(5.8)
Interest Expense (a)	—	0.4	—	0.4
Amortization of Prior Service Cost (Credit)	—	—	(5.0)	(5.0)
Amortization of Actuarial (Gains)/Losses	—	—	3.2	3.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	(5.9)	0.4	(1.8)	(7.3)
Income Tax (Expense) Credit	(1.3)	0.1	(0.4)	(1.6)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(4.6)	0.3	(1.4)	(5.7)
Net Current Period Other Comprehensive Income (Loss)	7.6	2.6	(1.4)	8.8
Balance in AOCI as of September 30, 2018	$(22.8)	$(12.7)	$(50.5)	$(86.0)

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 (a)	(0.9)	—	—	—	(0.9)
Purchased Electricity for Resale (a)	4.9	—	—	—	4.9
Interest Expense (a)	—	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 Nine Months Ended September 30, 2018

	Cash Flow Hedges				
	Commodity	Interest Rate	Securities Available for Sale	Pension and OPEB	Total
	(in millions)				
Balance in AOCI as of December 31, 2017	$(28.4)	$(13.0)	$ 11.9	$(38.3)	$(67.8)
Change in Fair Value Recognized in AOCI	30.4	2.3	—	—	32.7
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues (a)	(0.1)	—	—	—	(0.1)
Purchased Electricity for Resale (a)	(23.6)	—	—	—	(23.6)
Interest Expense (a)	—	0.9	—	—	0.9
Amortization of Prior Service Cost (Credit)	—	—	—	(14.7)	(14.7)
Amortization of Actuarial (Gains)/Losses	—	—	—	9.6	9.6
Reclassifications from AOCI, before Income Tax (Expense) Credit	(23.7)	0.9	—	(5.1)	(27.9)
Income Tax (Expense) Credit	(5.0)	0.2	—	(1.1)	(5.9)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(18.7)	0.7	—	(4.0)	(22.0)
Net Current Period Other Comprehensive Income (Loss)	11.7	3.0	—	(4.0)	10.7
ASU 2018-02 Adoption (b)	(6.1)	(2.7)	—	(8.2)	(17.0)
ASU 2016-01 Adoption (b)	—	—	(11.9)	—	(11.9)
Balance in AOCI as of September 30, 2018	$(22.8)	$(12.7)	$ —	$(50.5)	$(86.0)

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 (a)	(5.6)	—	—	—	(5.6)
Purchased Electricity for Resale (a)	26.0	—	—	—	26.0
Interest Expense (a)	—	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)

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AEP Texas

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2018

	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2018	$ (4.9)	$ (9.8)	$(14.7)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	0.4	—	0.4
Amortization of Prior Service Cost (Credit)	—	—	—
Amortization of Actuarial (Gains)/Losses	—	—	—
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.4	—	0.4
Income Tax (Expense) Credit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.3	—	0.3
Net Current Period Other Comprehensive Income (Loss)	0.3	—	0.3
Balance in AOCI as of September 30, 2018	$ (4.6)	$ (9.8)	$(14.4)

AEP Texas

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

	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2017	$ (4.9)	$ (9.4)	$(14.3)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	0.3	—	0.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	(0.1)
Amortization of Actuarial (Gains)/Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.3	0.1	0.4
Income Tax (Expense) Credit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.2	0.1	0.3
Net Current Period Other Comprehensive Income (Loss)	0.2	0.1	0.3
Balance in AOCI as of September 30, 2017	$ (4.7)	$ (9.3)	$(14.0)

AEP Texas

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2018

	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2017	$ (4.5)	$ (8.1)	$(12.6)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	1.0	—	1.0
Amortization of Prior Service Cost (Credit)	—	(0.1)	(0.1)
Amortization of Actuarial (Gains)/Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	1.0	0.1	1.1
Income Tax (Expense) Credit	0.2	—	0.2
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.8	0.1	0.9
Net Current Period Other Comprehensive Income (Loss)	0.8	0.1	0.9
ASU 2018-02 Adoption (b)	(0.9)	(1.8)	(2.7)
Balance in AOCI as of September 30, 2018	$ (4.6)	$ (9.8)	$(14.4)

AEP Texas

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

	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2016	$ (5.4)	$ (9.5)	$(14.9)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	1.0	—	1.0
Amortization of Prior Service Cost (Credit)	—	(0.1)	(0.1)
Amortization of Actuarial (Gains)/Losses	—	0.4	0.4
Reclassifications from AOCI, before Income Tax (Expense) Credit	1.0	0.3	1.3
Income Tax (Expense) Credit	0.3	0.1	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.7	0.2	0.9
Net Current Period Other Comprehensive Income (Loss)	0.7	0.2	0.9
Balance in AOCI as of September 30, 2017	$ (4.7)	$ (9.3)	$(14.0)

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2018

	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2018	$2.3	$ (2.7)	$(0.4)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	(0.4)	—	(0.4)
Amortization of Prior Service Cost (Credit)	—	(1.3)	(1.3)
Amortization of Actuarial (Gains)/Losses	—	0.4	0.4
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.4)	(0.9)	(1.3)
Income Tax (Expense) Credit	(0.1)	(0.2)	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.3)	(0.7)	(1.0)
Net Current Period Other Comprehensive Income (Loss)	(0.3)	(0.7)	(1.0)
Balance in AOCI as of September 30, 2018	$2.0	$ (3.4)	$(1.4)

APCo

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

	Cash Flow Hedge – 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 (a)	(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 Income (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 Nine Months Ended September 30, 2018

	Cash Flow Hedges			
	Commodity	Interest Rate	Pension and OPEB	Total
	(in millions)			
Balance in AOCI as of December 31, 2017	$ —	$ 2.2	$ (0.9)	$ 1.3
Change in Fair Value Recognized in AOCI	(0.7)	—	—	(0.7)
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity for Resale (a)	0.9	—	—	0.9
Interest Expense (a)	—	(0.9)	—	(0.9)
Amortization of Prior Service Cost (Credit)	—	—	(3.9)	(3.9)
Amortization of Actuarial (Gains)/Losses	—	—	1.0	1.0
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.9	(0.9)	(2.9)	(2.9)
Income Tax (Expense) Credit	0.2	(0.2)	(0.6)	(0.6)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.7	(0.7)	(2.3)	(2.3)
Net Current Period Other Comprehensive Income (Loss)	—	(0.7)	(2.3)	(3.0)
ASU 2018-02 Adoption (b)	—	0.5	(0.2)	0.3
Balance in AOCI as of September 30, 2018	$ —	$ 2.0	$ (3.4)	$ (1.4)

APCo

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

	Cash Flow Hedge – 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 (a)	(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 Income (Loss)	(0.5)	(0.9)	(1.4)
Balance in AOCI as of September 30, 2017	$ 2.4	$ (12.2)	$ (9.8)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2018

	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2018	$(12.2)	$(1.7)	$(13.9)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	0.4	—	0.4
Amortization of Prior Service Cost (Credit)	—	(0.2)	(0.2)
Amortization of Actuarial (Gains)/Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.4	—	0.4
Income Tax (Expense) Credit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.3	—	0.3
Net Current Period Other Comprehensive Income (Loss)	0.3	—	0.3
Balance in AOCI as of September 30, 2018	$(11.9)	$(1.7)	$(13.6)

I&M

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

	Cash Flow Hedge – 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 (a)	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 (Loss)	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 Nine Months Ended September 30, 2018

	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2017	$(10.7)	$(1.4)	$(12.1)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	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	0.3	—	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1.2	—	1.2
Net Current Period Other Comprehensive Income (Loss)	1.2	—	1.2
ASU 2018-02 Adoption (b)	(2.4)	(0.3)	(2.7)
Balance in AOCI as of September 30, 2018	$(11.9)	$(1.7)	$(13.6)

I&M

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

	Cash Flow Hedge – 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 (a)	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 (Loss)	1.0	—	1.0
Balance in AOCI as of September 30, 2017	$(11.0)	$(4.2)	$(15.2)

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2018

	Cash Flow Hedge – Interest Rate (in millions)
Balance in AOCI as of June 30, 2018	$ 1.7
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(0.5)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.5)
Income Tax (Expense) Credit	(0.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.4)
Net Current Period Other Comprehensive Income (Loss)	(0.4)
Balance in AOCI as of September 30, 2018	$ 1.3

OPCo

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

	Cash Flow Hedge – 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 (a)	(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 Income (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 Nine Months Ended September 30, 2018

	Cash Flow Hedge – Interest Rate (in millions)
Balance in AOCI as of December 31, 2017	$ 1.9
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1.3)
Income Tax (Expense) Credit	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(1.0)
Net Current Period Other Comprehensive Income (Loss)	(1.0)
ASU 2018-02 Adoption (b)	0.4
Balance in AOCI as of September 30, 2018	$ 1.3

OPCo

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

	Cash Flow Hedge – 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 (a)	(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 Income (Loss)	(0.8)
Balance in AOCI as of September 30, 2017	$ 2.2

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2018

	Cash Flow Hedge – Interest Rate (in millions)
Balance in AOCI as of June 30, 2018	$ 2.6
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(0.2)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.2)
Income Tax (Expense) Credit	—
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.2)
Net Current Period Other Comprehensive Income (Loss)	(0.2)
Balance in AOCI as of September 30, 2018	$ 2.4

PSO

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

	Cash Flow Hedge – 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 (a)	(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 Income (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 Nine Months Ended September 30, 2018

	Cash Flow Hedge – Interest Rate (in millions)
Balance in AOCI as of December 31, 2017	$ 2.6
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(0.9)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.9)
Income Tax (Expense) Credit	(0.2)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.7)
Net Current Period Other Comprehensive Income (Loss)	(0.7)
ASU 2018-02 Adoption (b)	0.5
Balance in AOCI as of September 30, 2018	$ 2.4

PSO

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

	Cash Flow Hedge – 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 (a)	(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 Income (Loss)	(0.6)
Balance in AOCI as of September 30, 2017	$ 2.8

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2018

	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2018	$(6.4)	$ 1.7	$(4.7)
Change in Fair Value Recognized in AOCI	2.3	—	2.3
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	0.5	—	0.5
Amortization of Prior Service Cost (Credit)	—	(0.5)	(0.5)
Amortization of Actuarial (Gains)/Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.5	(0.4)	0.1
Income Tax (Expense) Credit	0.1	(0.1)	—
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.4	(0.3)	0.1
Net Current Period Other Comprehensive Income (Loss)	2.7	(0.3)	2.4
Balance in AOCI as of September 30, 2018	$(3.7)	$ 1.4	$(2.3)

SWEPCo

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

	Cash Flow Hedge – 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 (a)	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 Nine Months Ended September 30, 2018

	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2017	$(6.0)	$ 2.0	$(4.0)
Change in Fair Value Recognized in AOCI	2.3	—	2.3
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	1.6	—	1.6
Amortization of Prior Service Cost (Credit)	—	(1.5)	(1.5)
Amortization of Actuarial (Gains)/Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	1.6	(1.3)	0.3
Income Tax (Expense) Credit	0.3	(0.3)	—
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1.3	(1.0)	0.3
Net Current Period Other Comprehensive Income (Loss)	3.6	(1.0)	2.6
ASU 2018-02 Adoption (b)	(1.3)	0.4	(0.9)
Balance in AOCI as of September 30, 2018	$(3.7)	$ 1.4	$(2.3)

SWEPCo

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

	Cash Flow Hedge – 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 (a)	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)

(a) Amounts reclassified to the referenced line item on the statements of income.
(b) See Note 2 - New Accounting Pronouncements for additional information.

4. RATE MATTERS

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

As discussed in the 2017 Annual Report, the Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2017 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2018 and updates the 2017 Annual Report.

Regulated Generating Unit to be Retired by 2020 (Applies to AEP and PSO)

In September 2018, management announced that the Oklaunion Power Station is probable of abandonment and is to be retired by October 2020. The table below summarizes the plant investment and cost of removal, currently being recovered, for the generating unit as of September 30, 2018. See "2018 Oklahoma Base Rate Case" below for additional information.

Gross Investment	Accumulated Depreciation	Net Investment	Materials and Supplies	Cost of Removal Regulatory Liability	Expected Retirement Date	Remaining Recovery Period
(dollars in millions)						
$106.5	$ 56.8	$ 49.7	$ 3.1	$ 5.0	2020	28 years

Regulatory Assets Pending Final Regulatory Approval (Applies to all Registrants except AEPTCo and OPCo)

	AEP	
	September 30, 2018	December 31, 2017
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs - Unrecovered Plant	$50.3	$ 50.3
Other Regulatory Assets Pending Final Regulatory Approval	20.1	9.6
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs (a)	151.7	128.0
Plant Retirement Costs - Asset Retirement Obligation Costs	39.7	39.7
Cook Plant Uprate Project	—	36.3
Cook Plant Turbine	—	15.9
Other Regulatory Assets Pending Final Regulatory Approval	18.8	42.2
Total Regulatory Assets Pending Final Regulatory Approval (b)	$280.6	$ 322.0

(a) As of September 30, 2018, AEP Texas has deferred $127 million related to Hurricane Harvey and is in the process of requesting securitization of the distribution portion of the regulatory asset.

(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. APCo's recovery of the remaining Virginia net book value for the retired plants will be considered in the Virginia SCC's 2020 triennial review of APCo's generation and distribution base rates. In 2017, the Virginia SCC staff requested that APCo prepare a depreciation study as of December 31, 2017 and submit that study to the Virginia SCC staff in 2018. In June 2018, APCo submitted the new depreciation study, based on December 31, 2017 property balances, to the Virginia SCC staff.

	AEP Texas	
	September 30, 2018	December 31, 2017
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs (a)	$150.2	$ 123.3
Rate Case Expense	0.2	0.1
Total Regulatory Assets Pending Final Regulatory Approval	$150.4	$ 123.4

(a) As of September 30, 2018, AEP Texas has deferred $127 million related to Hurricane Harvey and is in the process of requesting securitization of the distribution portion of the regulatory asset.

	APCo	
	September 30, 2018	December 31, 2017
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs - Materials and Supplies	$9.0	$ 9.1
Regulatory Assets Currently Not Earning a Return		
Plant Retirement Costs - Asset Retirement Obligation Costs	39.7	39.7
Other Regulatory Assets Pending Final Regulatory Approval	0.6	0.6
Total Regulatory Assets Pending Final Regulatory Approval (a)	$49.3	$ 49.4

(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. APCo’s recovery of the remaining Virginia net book value for the retired plants will be considered in the Virginia SCC’s 2020 triennial review of APCo’s generation and distribution base rates. In 2017, the Virginia SCC staff requested that APCo prepare a depreciation study as of December 31, 2017 and submit that study to the Virginia SCC staff in 2018. In June 2018, APCo submitted the new depreciation study, based on December 31, 2017 property balances, to the Virginia SCC staff.

	I&M	
	September 30, 2018	December 31, 2017
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Cook Plant Uprate Project	$—	$ 36.3
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	—	14.7
Cook Plant Turbine	—	15.9
Rockport Dry Sorbent Injection System - Indiana	—	10.4
Other Regulatory Assets Pending Final Regulatory Approval	3.4	2.0
Total Regulatory Assets Pending Final Regulatory Approval	$3.4	$ 79.3

PSO

Noncurrent Regulatory Assets	September 30, 2018	December 31, 2017
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	$—	$ 3.2
Other Regulatory Assets Pending Final Regulatory Approval	0.5	0.1
Total Regulatory Assets Pending Final Regulatory Approval	$0.5	$ 3.3

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	SWEPCo	
Noncurrent Regulatory Assets	September 30, 2018	December 31, 2017
	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs - Unrecovered Plant	$ 50.3	$ 50.3
Other Regulatory Assets Pending Final Regulatory Approval	0.5	0.5
Regulatory Assets Currently Not Earning a Return		
Asset Retirement Obligation - Arkansas, Louisiana	5.0	4.0
Rate Case Expense - Texas	4.6	4.3
Shipe Road Transmission Project - FERC	—	3.3
Other Regulatory Assets Pending Final Regulatory Approval	3.3	2.5
Total Regulatory Assets Pending Final Regulatory Approval	$ 63.7	$ 64.9

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

Impact of Tax Reform

Rate and regulatory matters are impacted by federal income tax implications. In December 2017, Tax Reform was enacted, which impacts outstanding rate and regulatory matters. For additional details on the impact of Tax Reform, see Note 11 - Income Taxes.

AEP Texas Rate Matters (Applies to AEP and AEP Texas)

AEP Texas Interim Transmission and Distribution Rates

As of September 30, 2018, AEP Texas' cumulative revenues from interim base rate increases from 2008 through 2018, subject to review, are estimated to be $959 million. A base rate review could produce a refund to customers 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.

In April 2018, the PUCT adopted a rule requiring investor-owned utilities operating solely within ERCOT to make periodic filings for rate proceedings. The rule requires AEP Texas to file for a comprehensive rate review no later than May 1, 2019.

In 2018, the PUCT issued approvals to increase AEP Texas' transmission rates by $22 million annually. The approvals included an increase in annual revenues to recover transmission capital additions of $46 million offset by a reduction in annual revenues of $24 million due to the reduction in the federal income tax rate due to Tax Reform. The approvals did not address the return of Excess ADIT benefits to customers.

In August 2018, the PUCT approved a Stipulation and Settlement agreement to amend AEP Texas' Distribution Cost Recovery Factor to reduce annual distribution rates by approximately $24 million annually, beginning September 1, 2018. The settlement included an increase in annual revenues to recover 2017 distribution capital additions of $19 million offset by reductions in annual revenues of: (a) $21 million due to the reduction in the federal income tax rate due to Tax Reform, (b) $10 million due to Excess ADIT associated with certain depreciable property to be amortized using ARAM and (c) $12 million due to Excess ADIT that is not subject to rate normalization requirements to be refunded over 5 years.

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, 2018, the total balance of AEP Texas' regulatory asset for deferred storm costs is approximately $150 million, inclusive of approximately $127 million of incremental storm expenses related to Hurricane Harvey. As of September 30, 2018, AEP Texas has recorded approximately $205 million of capital expenditures related to Hurricane Harvey. Also, as of September 30, 2018, AEP Texas has received $10 million in insurance proceeds, and has recorded a receivable for an additional $4 million that will be received in the fourth quarter of 2018, which were applied to the Hurricane Harvey related regulatory asset and property, plant and equipment balances. Management, in conjunction with the insurance adjusters, is reviewing all damages to determine the extent of coverage for additional insurance reimbursement. Any future insurance recoveries received will be applied to and will offset the regulatory asset and property, plant and equipment, as applicable.

Management believes the amount recorded as a regulatory asset is probable of recovery and is in the process of requesting securitization of the distribution portion of the regulatory asset. The standard process for securitization of storm cost recovery in Texas requires two filings with the PUCT. In August 2018, AEP Texas filed a Determination of System Restoration Costs with the PUCT for total estimated storm costs in the amount of $425 million, which includes estimated carrying costs. The estimated value of the total storm costs net of insurance proceeds, tax credits and Excess ADIT is $370 million. AEP Texas intends to request securitization for distribution related assets of $253 million while the remaining $117 million of transmission related assets will be recovered through interim transmission filings or an upcoming base rate case. The request for securitization is expected to occur by the first quarter of 2019.

In October 2018, intervenors filed testimony requesting a $24 million reduction in AEP Texas' Determination of System Restoration Costs. Also in October 2018, the PUCT staff filed testimony requesting a $4 million reduction AEP Texas' Determination of System Restoration Costs. Settlement negotiations are ongoing. 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.

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

Virginia Legislation Affecting Earnings 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 were frozen until after the Virginia SCC ruled on APCo's next biennial review. These amendments also precluded the Virginia SCC from performing biennial reviews of APCo's earnings for the years 2014 through 2017.

In March 2018, new Virginia legislation impacting investor-owned utilities was enacted, effective July 1, 2018, that: (a) on a one-time basis, required APCo to exclude $10 million of incurred fuel expenses from the July 2018 over/under recovery calculation, (b) reduced APCo's base rates by $50 million annually effective July 30, 2018, on an interim basis and subject to true-up, to reflect the reduction in the federal income tax rate due to Tax Reform, (c) will require APCo to file its next generation and distribution base rate case by March 31, 2020 using 2017, 2018 and 2019 test years ("triennial review"), (d) will require an adjustment in APCo's base rates on April 1, 2019 to reflect actual annual reductions in corporate income taxes due to Tax Reform, (e) will require APCo to seek approval from the Virginia SCC for energy efficiency programs with projected costs in the aggregate of at least $140 million over the 10-year period ending July 1, 2028 and (f) will require APCo to construct and/or acquire solar generation facilities in Virginia, as approved by the Virginia SCC, of at least 200 MW of aggregate capacity by July 1, 2028. Triennial reviews are subject to an earnings test which provides that 70% of any over earnings would be refunded or may be reinvested in approved energy distribution grid transformation projects and/or new utility-owned solar and wind generation facilities. The Virginia SCC's triennial review of 2017-2019 APCo earnings could reduce future net income and cash flows and impact financial condition.

Virginia Tax Reform

In October 2018, the Virginia SCC issued an order approving APCo's request to refund $55 million of Excess ADIT that is not subject to rate normalization requirements to customers through a rider. The rider will be paid over twelve months effective November 1, 2018 and will offset APCo's recent increase in interim fuel rates, subject to refund, that was filed with the Virginia SCC.

In October 2018, APCo submitted a filing with the Virginia SCC to resolve outstanding issues related to Tax Reform. The filing incorporated amounts already refunded to customers as disclosed in "Virginia Legislation Affecting Earnings Reviews" above and, if approved, will reduce APCo's base rates by an additional $7 million annually. The combined reduction in APCo's base rates due to Tax Reform will refund: (a) $39 million annually of excess federal income taxes collected since January 1, 2018 until new base rates are implemented, (b) $7 million annually of Excess ADIT associated with certain depreciable property using ARAM and (c) $11 million annually of Excess ADIT that is not subject to rate normalization requirements over 10 years. APCo anticipates a final order from the Virginia SCC in the first quarter of 2019 and expects to implement additional customer rate credits in a tax-related rider starting in April 2019. The Virginia SCC's review of APCo's October 2018 Tax Reform filing could reduce future net income and cash flows and impact financial condition.

2018 West Virginia Base Rate Case

In May 2018, APCo and WPCo filed a joint request with the WVPSC to increase their combined West Virginia base rates by $115 million ($98 million related to APCo) annually based on a 10.22% return on common equity. The proposed annual increase includes $32 million ($28 million related to APCo) due to increased annual depreciation rates and also reflects the impact of the reduction in the federal income tax rate due to Tax Reform. In October 2018, APCo and WPCo filed updated schedules supporting a $95 million ($80 million related to APCo) annual increase in West Virginia base rates primarily due to the impact of West Virginia Tax Reform discussed below.

In October 2018, WVPSC staff and intervenors filed testimony. WVPSC staff recommended a $2 million annual net revenue increase based on a 9.25% return on common equity while intervenors recommended a $14 million annual net revenue decrease based on an 8.75% return on common equity. The difference between APCo and WPCo's requested annual base rate increase and the WVPSC staff and intervenors recommendations are primarily due to: (a) a reduction in the requested return on common equity, (b) the rejection of updates to the rate base calculation methodology, (c) the rejection of updates to rate base for certain known plant in service increases in 2018 and (d) a reduction in annual depreciation rates primarily related to continuing with a 2040 retirement date for Clinch River Plant rather than APCo's proposed retirement date of 2025. A hearing at the WVPSC is scheduled for November 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

West Virginia Tax Reform

In August 2018, the WVPSC approved a settlement agreement between APCo, WPCo and various intervenors that addresses the reduction in the federal income tax rate due to Tax Reform. The agreement will provide refunds to customers, through a rider, of approximately $63 million ($51 million related to APCo) through June 2020. In addition, APCo and WPCo utilized $139 million ($125 million related to APCo) of current tax savings and Excess ADIT to offset regulatory asset balances related to carbon capture, storm damage, ENEC and vegetation management. The remaining balance of $87 million ($77 million related to APCo) of Excess ADIT that is not subject to rate normalization requirements will be addressed by the WVPSC at a later date.

ETT Rate Matters (Applies to AEP)

ETT Interim Transmission Rates

AEP 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, 2018, AEP's share of ETT's cumulative revenues that are subject to review is estimated to be $849 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. A revenue decrease, including a refund of interim transmission rates, could reduce future net income and cash flows and impact financial condition. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring.

In April 2018, the PUCT adopted a rule requiring investor-owned utilities operating solely inside ERCOT to make periodic filings for rate proceedings. The rule requires ETT to file for a comprehensive rate review no later than February 1, 2021.

In June 2018, the PUCT approved ETT's application to reduce its transmission rates by $28 million annually, beginning June 21, 2018, to reflect the reduction in the federal income tax rate due to Tax Reform. The filing did not address the return of Excess ADIT benefits to customers.

In September 2018, ETT filed a request with the PUCT to refund $11 million of excess federal income taxes collected in 2018 prior to the reduction in transmission rates that were implemented on June 21, 2018.

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.

In February 2018, I&M filed a Stipulation and Settlement Agreement for a $97 million annual increase in Indiana rates effective July 1, 2018 subject to a temporary offsetting reduction to customer bills through December 2018 for a credit rider related to the timing of estimated in-service dates of certain capital expenditures. The difference between I&M's requested $263 million annual increase and the $97 million annual increase in the Stipulation and Settlement Agreement is primarily a result of: (a) the reduction in the federal income tax rate due to Tax Reform, (b) the feedback of credits for Excess ADIT, (c) a 9.95% return on equity, (d) longer recovery periods of regulatory assets, (e) lower depreciation expense primarily for meters, (f) an increase in the sharing of off-system sales margins with customers from 50% to 95% and (g) a refund of $4 million from July 2018 through December 2018 for the impact of Tax Reform for the period January 2018 through June 2018.
In May 2018, the IURC issued an order approving the Stipulation and Settlement Agreement in its entirety.

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 included $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.

In February 2018, an MPSC ALJ issued a Proposal for Decision and recommended an annual revenue increase of $49 million, including an intervenor’s proposal for up to 10% of I&M’s Michigan retail customers to choose an alternate supplier for generation and a proposed capacity rate based on PJM’s net cost of new entry value of $289/MW-day, as well as the MPSC staff’s recommended calculation of depreciation expense for both units of Rockport Plant through 2028 and a return on common equity of 9.8%. If the maximum 10% of customers choose an alternate supplier starting in February 2019, the estimated annual pretax loss due to the reduced capacity rate would be approximately $9 million. In October 2018, I&M filed a request with the MPSC seeking authority to defer costs related to customers choosing an alternate supplier starting in February 2019.

In April 2018, the MPSC issued an order that generally approved the ALJ proposal resulting in an annual revenue increase of $50 million, effective April 2018 based on a 9.9% return on common equity. The MPSC also approved the ALJ’s recommendation related to the capacity rate.

In May 2018, I&M filed a Petition for Rehearing on the capacity rate issue. In June 2018, the MPSC denied I&M’s request.

Michigan Tax Reform

In August 2018, the MPSC approved I&M’s application to refund, through a rider, approximately $9 million annually for the impact of Tax Reform on I&M’s Michigan jurisdictional earnings effective September 1, 2018. In October 2018, I&M also made two filings with the MPSC recommending to: (a) refund $3 million over eight months for the impact of Tax Reform on Michigan jurisdictional earnings for the period April 26, 2018 through August 31, 2018, (b) refund approximately $68 million of Excess ADIT associated with certain depreciable property using ARAM and (c) refund approximately $37 million of Excess ADIT that is not subject to rate normalization requirements over 10 years. An order from the MPSC is expected by the end of the first quarter of 2019.

Rockport Plant, Unit 2 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. 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 and is expected to be placed in service in May 2020. The estimated cost of the SCR project is $274 million, excluding AFUDC, to be shared equally between I&M and AEGCo. The filing included a request for authorization for I&M to defer its Indiana jurisdictional ownership share of costs including investment carrying costs 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.

In March 2018, the IURC issued an order approving: (a) the CPCN, (b) the $274 million estimated cost of the SCR, excluding AFUDC, (c) deferral of the Indiana jurisdictional ownership share of costs, including investment carrying costs, (d) depreciation of the SCR asset over 10 years and (e) recovery of these costs using an I&M Indiana rider.

In April 2018, a group of intervenors filed a Petition for Reconsideration and Rehearing of the March 2018 IURC order. In June 2018, the IURC denied the Petition for Reconsideration and Rehearing.

Management intends to request recovery of the Michigan jurisdictional share of the SCR project in a future base rate case. The AEGCo ownership share of the SCR project will be billable under the Rockport UPA to I&M and KPCo and will be subject to future regulatory approval for recovery.

KPCo Rate Matters (Applies to AEP)

2017 Kentucky Base Rate Case

In January 2018, the KPSC issued an order approving a non-unanimous settlement agreement with certain modifications resulting in an annual revenue increase of $12 million, effective January 2018, based on a 9.7% return on equity. The KPSC's primary revenue requirement modification to the settlement agreement was a $14 million annual revenue reduction for the decrease in the corporate federal income tax rate due to Tax Reform. The KPSC approved: (a) the deferral of a total of $50 million of Rockport Plant UPA expenses for the years 2018 through 2022, with the manner and timing of recovery of the deferral to be addressed in KPCo's next base rate case, (b) the recovery/return of 80% of certain annual PJM OATT expenses above/below the corresponding level recovered in base rates, (c) KPCo's commitment to not file a base rate case for three years with rates effective no earlier than 2021 and (d) increased depreciation expense based upon updated Big Sandy Plant, Unit 1 depreciation rates using a 20-year depreciable life.

In February 2018, KPCo filed with the KPSC for rehearing of the January 2018 base case order and requested an additional $2.3 million of annual revenue increases related to: (a) the calculation of federal income tax expense, (b) recovery of purchased power costs associated with forced outages and (c) capital structure adjustments. Also in February 2018, an intervenor filed for rehearing recommending that the reduced corporate federal income tax rate be reflected in lower purchased power expense related to the Rockport UPA.

In April 2018, KPCo and the intervenor filed a settlement agreement with the KPSC in which KPCo withdrew its requested increase related to the recovery of purchased power costs associated with forced outages and the intervenor withdrew its claim regarding the impact of the reduced corporate federal income tax rates on purchased power costs related to the Rockport UPA.

In June 2018, the KPSC issued an order approving the settlement agreement including KPCo's requested additional revenue increase of $765 thousand related to the calculation of federal income tax expense. This rate increase was effective June 28, 2018.

Kentucky Tax Reform

In June 2018, the KPSC issued an order approving a settlement agreement between KPCo and an intervenor that stipulates that KPCo will refund an estimated $82 million of Excess ADIT associated with certain depreciable property using ARAM and an estimated $93 million of Excess ADIT that is not subject to rate normalization requirements over 18 years. The refund was effective July 1, 2018.

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 and 2016, the PUCO issued orders in this proceeding. As part of the issued orders, the PUCO approved: (a) the DIR with modified revenue caps, (b) recovery of OVEC-related net margin incurred beginning June 2016, (c) 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 (d) the limitation that OPCo will not flow through any capacity performance penalties or bonuses through the PPA rider. Additionally, subject to cost recovery and PUCO approval, OPCo agreed to develop and implement, by 2021, a solar energy project(s) of at least 400 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 April 2017, the PUCO rejected all pending rehearing requests related to the OVEC PPA. 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 June 2018, oral arguments were held before the Supreme Court of Ohio.

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.

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 April 2018, the PUCO issued an order approving the ESP extension stipulation agreement, with no significant changes. In May 2018, OPCo and various intervenors filed requests for rehearing with the PUCO. In June 2018, these requests for rehearing were approved to allow further consideration of the requests. In August 2018, the PUCO denied all requests for rehearing. In October 2018, an intervenor filed an appeal with the Ohio Supreme Court challenging various approved riders.

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 that was filed at the PUCO in December 2016 and subsequently approved in February 2017: (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.

In January 2018, PUCO staff filed testimony that OPCo did not have significantly excessive earnings. Also in January 2018, an intervenor filed testimony recommending a $53 million refund to customers. In February 2018, OPCo and

PUCO staff filed a stipulation agreement in which both parties agreed that OPCo did not have significantly excessive earnings in 2016.

A 2016 SEET hearing was held in April 2018 and management expects to receive an order in the first half of 2019. While 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 proposed SEET adjustments, including treatment of the Global Settlement issues described above, adjust the comparable risk group or adopt a different 2016 SEET threshold. If the PUCO orders a refund of 2016 OPCo earnings, it could negatively affect future SEET filings, reduce future net income and cash flows and impact financial condition.

Ohio Tax Reform

In October 2018, the PUCO issued an order approving a September 2018 settlement agreement between OPCo and various intervenors that addresses the reduction in the federal income tax rate due to Tax Reform. The settlement will: (a) refund excess federal income tax of $20 million annually, through a rider, effective January 1, 2018 until new base rates are implemented, (b) refund an estimated $278 million of Excess ADIT associated with depreciable property through OPCo's DIR, (c) utilize $48 million of Excess ADIT that is not subject to rate normalization to offset regulatory asset balances related to OPCo's distribution decoupling program and (d) refund the remaining estimated $129 million of Excess ADIT that is not subject to rate normalization by December 31, 2024 through a rider.

PSO Rate Matters (Applies to AEP and PSO)

2018 Oklahoma Base Rate Case

In October 2018, PSO filed a request with the OCC for an $88 million annual increase in Oklahoma retail rates based upon a 10.3% return on common equity. PSO also proposed to implement a performance based rate plan that combines a formula rate with a set of customer-focused performance incentive measures related to reliability, public safety, customer satisfaction and economic development. The proposed annual increase includes $13 million related to increased annual depreciation rates and $7 million related to increased storm expense amortization. The requested increase in annual depreciation rates includes the recovery of Oklaunion Power Station through 2028 (currently being recovered in rates through 2046). Management has announced plans to retire Oklaunion Power Station by October 2020. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Oklahoma Tax Reform

In August 2018, the OCC issued an order that approved PSO's compliance filing that addresses the reduction in the federal income tax rate due to Tax Reform. As a result of the order PSO will establish a rider to: (a) refund $3 million of excess federal income taxes collected from January 9, 2018 through February 28, 2018 by the end of 2018, (b) refund an estimated $353 million of Excess ADIT associated with certain depreciable property using ARAM and (c) refund an estimated $72 million of Excess ADIT that is not subject to rate normalization requirements over 10 years.

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.

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, SWEPCo reversed $114 million of previously recorded regulatory disallowances in 2013. 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.

In July 2018, the Texas Third Court of Appeals reversed the PUCT's judgment affirming the prudence of the Turk Plant and remanded the issue back to the PUCT. In August 2018, SWEPCo filed a Motion for Reconsideration at the Court of Appeals. In October 2018, the Court of Appeals denied SWEPCo's request. SWEPCo intends to file an appeal with the Texas Supreme Court in the fourth quarter of 2018.

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. In January 2018, the PUCT issued a final order approving a net increase in Texas annual revenues of $50 million based upon a return on common equity of 9.6%, effective May 2017. The final order also included: (a) approval to recover the Texas jurisdictional share of environmental investments placed in service, as of June 30, 2016, at various plants, including Welsh Plant, Units 1 and 3, (b) approval of recovery of, but no return on, the Texas jurisdictional share of the net book value of Welsh Plant, Unit 2, (c) approval of $2 million in additional vegetation management expenses and (d) the rejection of SWEPCo's proposed transmission cost recovery mechanism.

As a result of the final order, in 2017 SWEPCo: (a) recorded an impairment charge of $19 million, which included $7 million associated with the lack of return on Welsh Plant, Unit 2 and $12 million related to other disallowed plant investments, (b) recognized $32 million of additional revenues, for the period of May 2017 through December 2017, that will be surcharged to customers and (c) recognized an additional $7 million of expenses consisting primarily of depreciation expense and vegetation management expense, offset by the deferral of rate case expense. SWEPCo implemented new rates in February 2018 billings. The $32 million of additional 2017 revenues will be collected by the end of 2018. In March 2018, the PUCT clarified and corrected portions of the final order, without changing the overall decision or amounts of the rate change. The order has been appealed by various intervenors.

In April 2018, SWEPCo made an income tax rate refund tariff filing which includes an annual revenue reduction of approximately $18 million to reflect the difference between rates collected under the final order and the rates that would be collected under Tax Reform. The filing did not address the return of Excess ADIT benefits to customers. In June 2018, the ALJ issued an order approving interim rates that provided for a reduction of residential rates of $8 million. In September 2018, the ALJ issued an order approving interim rates for the remaining customers. The matter has been sent to the PUCT for final approval.

Texas Tax Reform

In October 2018, SWEPCo filed a Stipulation and Settlement Agreement with the PUCT to refund $10 million of excess federal income taxes collected, as a result of Tax Reform, from January 1, 2018 through June 14, 2018 for residential customers and January 1, 2018 through September 19, 2018 for all other customer classes. An interim order was issued by an ALJ and the refunds will be made to customers through a rider in the fourth quarter of 2018.

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. In February 2018, LPSC staff filed a report approving the increase as filed. This increase is subject to refund pending commission approval. 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. 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. These environmental costs are subject to prudence review by the LPSC. In May 2018, LPSC staff filed testimony that the environmental control investment for Welsh Plant, Units 1 and 3 and Flint Creek power plants is prudent. In August 2018, the LPSC issued an order affirming prudence and approved the settlement agreement for the environmental control investment. In October 2018, the LPSC staff filed a report approving the $31 million increase as filed. The net annual increase is subject to refund pending commission approval. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2018 Louisiana Formula Rate Filing

In April 2018, SWEPCo filed its formula rate plan for test year 2017 with the LPSC. The filing included a net $28 million annual increase, which was effective August 2018 and includes SWEPCo’s Louisiana jurisdictional share of Welsh Plant and Flint Creek Plant environmental controls. The filing also included a reduction in the federal income tax rate due to Tax Reform but did not address the return of Excess ADIT benefits to customers.

In July 2018, SWEPCo made a supplemental filing to its formula rate plan with the LPSC to reduce the requested annual increase to $18 million. The difference between SWEPCo’s requested $28 million annual increase and the $18 million annual increase in the supplemental filing is primarily the result of the return of Excess ADIT benefits to customers.
In October 2018, the LPSC staff issued a recommendation that SWEPCo refund $11 million of excess federal income taxes collected, as a result of Tax Reform, from January 1, 2018 through July 31, 2018. A decision by the LPSC is expected in the fourth quarter of 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 $550 million, excluding AFUDC. As of September 30, 2018, SWEPCo had incurred costs of $399 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, 2018, the total net book value of Welsh Plant, Units 1 and 3 was $621 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 April 2017, the LPSC approved recovery of $131 million in investments related to its Louisiana jurisdictional share of environmental controls installed at Welsh Plant, effective May 2017. SWEPCo’s approved Louisiana jurisdictional share of Welsh Plant deferrals: (a) are $10 million, excluding $6 million of unrecognized equity as of September 30, 2018, (b) is subject to review by the LPSC and (c) includes a WACC return on environmental investments and the related depreciation expense and taxes. See “2017 Louisiana Formula Rate Filing” and “2018 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.

Arkansas Tax Reform

In September 2018, the APSC issued an order that approved SWEPCo's application to implement a rider for SWEPCo's Arkansas jurisdiction to address the reduction in the federal income tax rate due to Tax Reform. The rider was implemented in the first billing cycle of October 2018 and will: (a) refund $7 million over 15 months of excess federal income taxes collected from January 1, 2018 through September 30, 2018, (b) refund an ongoing estimated $655 thousand monthly from October 1, 2018 until new base rates go into effect as a result of a subsequent APSC order, (c) refund an estimated $66 million of Excess ADIT associated with certain depreciable property using ARAM and (d) refund an estimated $11 million of Excess ADIT that is not subject to rate normalization requirements over 15 months.

FERC Rate Matters

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

In June 2016, PJM transmission owners, including AEP's transmission owning subsidiaries within PJM, 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. In May 2018, the FERC approved the contested settlement agreement. PJM implemented a transmission enhancement charge adjustment through the PJM OATT, which will be billable through 2025. Management expects that any refunds received would generally be returned to retail customers through existing state rider mechanisms and has recorded $134 million to Customer Accounts Receivable and $75 million to Deferred Charges and Other Noncurrent Assets, with offsets to Regulatory Liabilities and Deferred Investment Tax Credits as of September 30, 2018.

FERC Transmission Complaint - AEP's PJM Participants (Applies to AEP, AEPTCo, APCo, I&M and OPCo)

In October 2016, seven parties filed a complaint at the FERC that alleged the base return on common equity used by AEP's transmission owning subsidiaries within PJM 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 November 2017, a FERC order set the matter for hearing and settlement procedures. In March 2018, AEP's transmission owning subsidiaries within PJM and six of the complainants filed a settlement agreement with the FERC (the seventh complainant abstained). If approved by the FERC the settlement agreement: (a) establishes a base ROE for AEP's transmission owning subsidiaries within PJM of 9.85% (10.35% inclusive of the RTO incentive adder of 0.5%), effective January 1, 2018, (b) requires AEP's transmission owning subsidiaries within PJM to provide a one-time refund of $50 million, attributable from the date of the complaint through December 31, 2017, which was credited to customer bills in the second quarter of 2018 and (c) increases the cap on the equity portion of the capital structure to 55% from 50%. As part of the settlement agreement, AEP's transmission owning subsidiaries within PJM also filed updated transmission formula rates incorporating the reduction in the corporate federal income tax rate due to Tax Reform, effective January 1, 2018 and providing for the amortization of the portion of the Excess ADIT that is not subject to the normalization method of accounting, ratably over a ten-year period through credits to the federal income tax expense component of the revenue requirement. In April 2018, an ALJ accepted the interim settlement rates, which included the $50 million one-time refund that occurred in the second quarter of 2018. These interim rates are subject to refund or surcharge, with interest.

In April 2018, certain intervenors filed comments at the FERC recommending a base ROE of 8.48% and a one-time refund of $184 million. The FERC trial staff filed comments recommending a base ROE of 8.41% and one-time refund of $175 million. Another intervenor recommended the refund be calculated in accordance with the base ROE that will ultimately be approved by the FERC. In May 2018, management filed reply comments providing further support for the 9.85% base ROE agreed to in the settlement agreement.

If the FERC orders revenue reductions in excess of the terms of the settlement agreement, it could reduce future net income and cash flows and impact financial condition. A decision from the FERC is pending.

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

In November 2016, AEP's transmission owning subsidiaries within PJM 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. The modified PJM OATT formula rates are based on projected calendar year financial activity and projected plant balances. In December 2017, AEP's transmission owning subsidiaries within PJM filed an uncontested settlement agreement with the FERC resolving all outstanding issues. In April 2018, the FERC approved the uncontested settlement agreement and rates were implemented effective January 1, 2018.

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

In June 2017, several parties filed a complaint at the FERC that states the base return on common equity used by AEP's transmission owning subsidiaries within 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 through September 5, 2018. In November 2017, a FERC order set the matter for hearing and settlement procedures. The parties were unable to settle and the proceeding is currently in the hearing phase.

In September 2018, the same parties filed another complaint at the FERC that states the base return on common equity used by AEP's transmission owning subsidiaries within SPP in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.71%, effective upon the date of the second complaint.

Management believes its financial statements adequately address the impact of these complaints. If the FERC orders revenue reductions as a result of these complaints, including refunds from the date of the complaint filings, it could reduce future net income and cash flows and impact financial condition.

Modifications to AEP's SPP Transmission Rates (Applies to AEP, AEPTCo, PSO and SWEPCo)

In October 2017, AEP's transmission owning subsidiaries within SPP filed an application at the FERC to modify the SPP OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to projected expenses. The modified SPP OATT formula rates are based on projected calendar year financial activity and projected plant balances. In December 2017, the FERC accepted the proposed modifications effective January 1, 2018, subject to refund, and set this matter for hearing and settlement procedures. 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 SWEPCo Power Supply Agreements Complaint - East Texas Electric Cooperative, Inc. (ETEC) and Northeast Texas Electric Cooperative, Inc. (NTEC) (Applies to AEP and SWEPCo)

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 its power supply formula rates is excessive and should be reduced from 11.1% to 8.41%, effective upon the date of the complaint. In November 2017, a FERC order set the matter for hearing and settlement procedures.

In May 2018, SWEPCo filed a settlement agreement with ETEC and NTEC at the FERC that resolves the issues of the complaint. If approved by the FERC, the settlement agreement: (a) reduces the base return on common equity from 11.1% to 10.1% effective September 1, 2017, (b) requires SWEPCo to provide a one-time billing credit of $287 thousand to reflect the decrease in return on common equity from September 1, 2017 through December 31, 2017 and

(c) implements the lower return on common equity on contracts starting January 1, 2018. In July 2018, the FERC issued an order approving the settlement.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

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

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2017 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letters of Credit (Applies to AEP, AEP Texas 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, 2018, no letters of credit were issued under the $3 billion revolving credit facility. In October 2018, the revolving credit facility was increased to $4 billion and extended until June 2022.

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 on behalf of subsidiaries under four uncommitted facilities totaling $305 million. The Registrants’ maximum future payments for letters of credit issued under the uncommitted facilities as of September 30, 2018 were as follows:

Company	Amount (in millions)	Maturity
AEP	$ 71.8	October 2018 to September 2019
AEP Texas	2.8	January 2019
OPCo	0.6	September 2019

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

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 $140 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and completion of final reclamation. It is estimated the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of $79 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of September 30, 2018, SWEPCo has collected $74 million through a rider for final mine closure and reclamation costs, of which $79 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)

In December 2016, 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, 2018, 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, 2018, there were no material liabilities recorded for any indemnifications.

AEPSC conducts power purchase and sale activity on behalf of APCo, I&M, KPCo and WPCo, who are jointly and severally liable for activity conducted on their behalf. AEPSC also conducts power purchase and sale activity on behalf of PSO and SWEPCo, who are jointly and severally liable for activity conducted on their behalf.

Master Lease Agreements (Applies to all Registrants except AEPTCo)

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, 2018, 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	$ 47.7
AEP Texas	11.4
APCo	8.8
I&M	3.5
OPCo	7.6
PSO	4.1
SWEPCo	4.2

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 have exercised all renewal options for the maximum lease term. The future minimum lease obligations were $7 million and $7 million for I&M and SWEPCo, respectively, for the remaining railcars as of September 30, 2018.

Under the remaining five-year 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 is equal to 77% of the projected fair value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. The maximum potential losses related to the guarantee were $5 million and $5 million for I&M and SWEPCo, respectively, as of September 30, 2018, 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, 2018, the maximum potential amount of future payments required under the guaranteed leases was $46 million. In certain instances, AEP has no recourse against the nonaffiliated party if required to pay a lessor under a guarantee, but AEP would have access to sell the leased assets in order to recover payments made by AEP under the guarantee. As of September 30, 2018, AEP’s boat and barge lease guarantee liability was $6 million, of which $1 million was recorded in Other Current Liabilities and $5 million was recorded in Deferred Credits and Other Noncurrent Liabilities on AEP’s balance sheet.

In January 2018, S&P Global Inc. downgraded the ratings of the nonaffiliated party and set their outlook to negative. In April 2018, Moody’s Investors Service Inc. also downgraded their ratings and set their outlook to negative. It is reasonably possible that enforcement of AEP’s liability for future payments under these leases could be exercised, which could reduce future net income and cash flows and impact financial condition.

ENVIRONMENTAL CONTINGENCIES (Applies to all Registrants except AEPTCo)

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. For remediation processes not specifically discussed, management does not anticipate that the liabilities, if any, arising from such remediation processes would have a material effect on the financial statements.

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. 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

In March 2017, Westinghouse filed a petition to reorganize under Chapter 11 of the U.S. Bankruptcy Code. 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. As part of the reorganization, the bankruptcy court approved Westinghouse's sale of its nuclear business to Brookfield WEC Holdings (Brookfield), a nonaffiliated third party. Pursuant to the sale, Brookfield will assume all of I&M's contracts with Westinghouse. In August 2018, the sale closed.

OPERATIONAL CONTINGENCIES

Rockport Plant Litigation (Applies to AEP and I&M)

In July 2013, the Wilmington Trust Company filed a complaint in the U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it would 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 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.

AEGCo and I&M sought and were granted dismissal of certain of the plaintiffs' claims, including claims for compensatory damages, breach of contract, breach of the implied covenant of good faith and fair dealing and indemnification of costs. 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. Plaintiffs voluntarily dismissed the surviving claims with prejudice, and the court issued a final judgment. The plaintiffs subsequently filed an appeal in the U.S. Court of Appeals for the Sixth Circuit on whether the trial court erred in dismissing plaintiffs' claims for breach of contract and breach of the implied 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 in part. In June 2017, on rehearing, the court of appeals issued an amended opinion reversing the district court's dismissal of certain of plaintiffs' claims for breach of contract, vacating the denial of the plaintiffs' motion for partial summary judgment and remanding the case to the district court for further proceedings. The amended opinion and judgment affirmed 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 removed 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 in the original NSR litigation, seeking to modify the consent decree to eliminate the obligation to install certain 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. Responsive and supplemental filings have been made by all parties. In November 2017, the district court granted the owners' unopposed motion to stay the lease litigation to afford time for resolution of AEP's motion to modify the consent decree. In September 2018, the district court granted AEP's unopposed motion to stay further proceedings regarding the consent decree to facilitate settlement discussions among the parties to 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.

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 became 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 pursued personal injury/illness claims (non-working direct claims) and the remainder pursued loss of consortium claims. The plaintiffs sought 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. In June 2017, the West Virginia Supreme Court reversed the WVMLP decision and dismissed the claims of the twelve non-working direct claim plaintiffs. A settlement was reached with all of the plaintiffs and was approved by the WVMLP in June 2018. The settlement did not have a material impact on net income, cash flows or financial condition.

6. DISPOSITIONS AND IMPAIRMENTS

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

DISPOSITIONS

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.

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.

IMPAIRMENTS

Other Assets (Corporate and Other) (Vertically Integrated Utilities Segment) (Applies to AEP and APCo)

In the first quarter of 2018, AEP was notified by an equity investee that it had ceased operations. AEP recorded a pretax impairment of $21 million in Other Operation on the statement of income related to the equity investment and related assets. The impairment also had an immaterial impact to APCo.

Merchant Generating Assets (Generation & Marketing Segment)

A project to reconstruct a defective dam structure at Racine began in the first quarter of 2017. In December 2017, and in accordance with the accounting guidance for impairments of long-lived assets, an impairment analysis was triggered by the expected costs of the dam reconstruction activities, resulting in the conclusion that the fair value of Racine, in its present condition, was $0 as of December 31, 2017. A pretax impairment charge equal to Racine's net book value of $43 million was recognized in AEP's 2017 statement of income.

Construction activities at Racine continued throughout 2018, accumulating new capital expenditures of $35 million as of September 30, 2018. However, due to a significant increase in estimated costs to complete the reconstruction project, in the third quarter of 2018, an impairment analysis was performed. AEP performed step one of the impairment analysis using undiscounted cash flows for the estimated useful life of Racine based upon energy and capacity price curves, which were developed internally with observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. AEP performed step two of the impairment analysis on Racine using a ten-year discounted cash flow model based upon similar forecasted information used in the step one test. The step two analysis resulted in a determination that the fair value of Racine, in its present condition, was $0 as of September 30, 2018. As a result, AEP recorded a pretax impairment of $35 million in Other Operation on the statement of income in the third quarter of 2018. In October

2018, AEP received authorization from the FERC to restart generation at Racine. Management plans to resume generation at Racine during the fourth quarter of 2018.

In the first quarter of 2017, AEP recorded a pretax impairment of $4 million in Other Operation on the statement of income related to the Merchant Coal-fired Generation Assets. In addition, AEP recorded a $7 million pretax impairment in Other Operation on the statement of income related to the sale of Zimmer Plant.

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 Three Months Ended September 30,		OPEB Three Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$24.4	$24.1	$2.9	$2.8
Interest Cost	46.9	50.7	11.8	14.8
Expected Return on Plan Assets	(72.6)	(71.1)	(25.6)	(25.3)
Amortization of Prior Service Cost (Credit)	—	0.3	(17.3)	(17.3)
Amortization of Net Actuarial Loss	21.3	20.7	2.7	9.2
Net Periodic Benefit Cost (Credit)	$20.0	$24.7	$(25.5)	$(15.8)

	Pension Plans Nine Months Ended September 30,		OPEB Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$73.2	$72.3	$8.7	$8.4
Interest Cost	140.8	152.3	35.5	44.5
Expected Return on Plan Assets	(217.7)	(213.5)	(76.7)	(76.0)
Amortization of Prior Service Cost (Credit)	—	0.8	(51.8)	(51.8)
Amortization of Net Actuarial Loss	63.9	62.1	7.9	27.5
Net Periodic Benefit Cost (Credit)	$60.2	$74.0	$(76.4)	$(47.4)

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AEP Texas

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$2.3	$2.1	$0.3	$0.3
Interest Cost	4.0	4.3	0.9	1.2
Expected Return on Plan Assets	(6.4)	(6.2)	(2.1)	(2.2)
Amortization of Prior Service Credit	—	—	(1.5)	(1.5)
Amortization of Net Actuarial Loss	1.8	1.7	0.2	0.8
Net Periodic Benefit Cost (Credit)	$1.7	$1.9	$(2.2)	$(1.4)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$6.9	$6.4	$0.7	$0.7
Interest Cost	12.0	12.9	2.8	3.7
Expected Return on Plan Assets	(19.2)	(18.8)	(6.4)	(6.6)
Amortization of Prior Service Credit	—	—	(4.4)	(4.4)
Amortization of Net Actuarial Loss	5.4	5.2	0.6	2.4
Net Periodic Benefit Cost (Credit)	$5.1	$5.7	$(6.7)	$(4.2)

APCo

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$2.4	$2.3	$0.3	$0.3
Interest Cost	5.8	6.5	2.1	2.6
Expected Return on Plan Assets	(9.1)	(8.9)	(4.0)	(4.1)
Amortization of Prior Service Credit	—	—	(2.5)	(2.5)
Amortization of Net Actuarial Loss	2.6	2.6	0.4	1.6
Net Periodic Benefit Cost (Credit)	$1.7	$2.5	$(3.7)	$(2.1)

OPEB

	Pension Plans Nine Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$7.0	$7.0	$0.8	$0.8
Interest Cost	17.6	19.3	6.2	7.9
Expected Return on Plan Assets	(27.4)	(26.8)	(12.0)	(12.3)
Amortization of Prior Service Cost (Credit)	—	0.1	(7.5)	(7.5)
Amortization of Net Actuarial Loss	7.9	7.8	1.4	4.7
Net Periodic Benefit Cost (Credit)	$5.1	$7.4	$(11.1)	$(6.4)

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I&M

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$3.4	$3.5	$0.4	$0.4
Interest Cost	5.6	6.1	1.4	1.7
Expected Return on Plan Assets	(9.0)	(8.6)	(3.1)	(3.1)
Amortization of Prior Service Credit	—	—	(2.4)	(2.3)
Amortization of Net Actuarial Loss	2.5	2.4	0.3	1.1
Net Periodic Benefit Cost (Credit)	$2.5	$3.4	$(3.4)	$(2.2)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$10.2	$10.5	$1.2	$1.2
Interest Cost	16.6	18.2	4.1	5.2
Expected Return on Plan Assets	(26.8)	(25.9)	(9.3)	(9.2)
Amortization of Prior Service Cost (Credit)	—	0.1	(7.1)	(7.0)
Amortization of Net Actuarial Loss	7.4	7.3	0.9	3.3
Net Periodic Benefit Cost (Credit)	$7.4	$10.2	$(10.2)	$(6.5)

OPCo

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$2.0	$1.8	$0.2	$0.3
Interest Cost	4.4	4.8	1.3	1.6
Expected Return on Plan Assets	(7.2)	(6.9)	(2.9)	(3.0)
Amortization of Prior Service Credit	—	—	(1.7)	(1.7)
Amortization of Net Actuarial Loss	2.0	2.0	0.3	1.1
Net Periodic Benefit Cost (Credit)	$1.2	$1.7	$(2.8)	$(1.7)

	Pension Plans		OPEB	
	Nine Months		Nine Months Ended	

	Ended September 30,		September 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$5.8	$5.6	$0.7	$0.7
Interest Cost	13.3	14.5	3.9	5.0
Expected Return on Plan Assets	(21.6)	(20.9)	(8.8)	(9.0)
Amortization of Prior Service Cost (Credit)	—	0.1	(5.2)	(5.2)
Amortization of Net Actuarial Loss	6.0	5.9	0.8	3.3
Net Periodic Benefit Cost (Credit)	$3.5	$5.2	$(8.6)	$(5.2)

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PSO

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$1.7	$1.7	$0.1	$0.2
Interest Cost	2.5	2.6	0.6	0.8
Expected Return on Plan Assets	(4.0)	(3.9)	(1.3)	(1.4)
Amortization of Prior Service Credit	—	—	(1.1)	(1.1)
Amortization of Net Actuarial Loss	1.1	1.1	0.1	0.5
Net Periodic Benefit Cost (Credit)	$1.3	$1.5	$(1.6)	$(1.0)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$5.3	$4.9	$0.5	$0.5
Interest Cost	7.4	8.0	1.8	2.4
Expected Return on Plan Assets	(12.1)	(11.8)	(4.1)	(4.2)
Amortization of Prior Service Credit	—	—	(3.2)	(3.2)
Amortization of Net Actuarial Loss	3.3	3.3	0.4	1.5
Net Periodic Benefit Cost (Credit)	$3.9	$4.4	$(4.6)	$(3.0)

SWEPCo

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$2.4	$2.1	$0.2	$0.2
Interest Cost	2.8	3.1	0.7	0.9
Expected Return on Plan Assets	(4.4)	(4.2)	(1.6)	(1.5)
Amortization of Prior Service Credit	—	—	(1.3)	(1.3)
Amortization of Net Actuarial Loss	1.3	1.3	0.2	0.5
Net Periodic Benefit Cost (Credit)	$2.1	$2.3	$(1.8)	$(1.2)

OPEB

	Pension Plans Nine Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$7.0	$6.5	$0.7	$0.6
Interest Cost	8.5	9.2	2.1	2.7
Expected Return on Plan Assets	(13.1)	(12.6)	(4.8)	(4.7)
Amortization of Prior Service Credit	—	—	(3.9)	(3.9)
Amortization of Net Actuarial Loss	3.8	3.7	0.5	1.7
Net Periodic Benefit Cost (Credit)	$6.2	$6.8	$(5.4)	$(3.6)

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 AEP Texas and OPCo.
- OPCo purchases energy and capacity to serve SSO customers and provides transmission and distribution services for all connected load.

AEP Transmission Holdco

- Development, construction and operation of transmission facilities through investments in 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, 2018 and 2017 and reportable segment balance sheet information as of September 30, 2018 and December 31, 2017.

Three Months Ended September 30, 2018	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	$2,610.2	$ 1,180.9	$ 51.9	$ 486.5	$ 3.6	$ —	$ 4,333.1
Other Operating Segments	26.5	30.6	135.3	35.1	20.1	(247.6)	—
Total Revenues	$2,636.7	$ 1,211.5	$ 187.2	$ 521.6	$ 23.7	$ (247.6)	$ 4,333.1
Net Income (Loss)	$345.6	$ 145.2	$ 74.2	$ 5.1	$ 9.6	$ —	$ 579.7

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
Net Income (Loss)	$297.3	$ 144.0	$ 76.5	$ 33.7	$ 5.2	$ —	$ 556.7

Nine Months Ended September 30, 2018	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	$7,332.4	$ 3,450.0	$ 196.5	$ 1,399.3	$ 16.4	$ —	$ 12,394.6
Other Operating Segments	61.3	60.9	408.7	88.1	55.1	(674.1)	—
Total Revenues	$7,393.7	$ 3,510.9	$ 605.2	$ 1,487.4	$ 71.5	$ (674.1)	$ 12,394.6
Net Income (Loss)	$856.3	$ 384.6	$ 280.9	$ 61.8	$ (17.1)	$ —	$ 1,566.5

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

Net Income (Loss)	$639.2	$ 374.3	$ 278.3	$ 246.3	$ (11.0)	$ —	$ 1,527.1

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	September 30, 2018						
	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	$44,553.4	$17,619.1	$8,130.3	$864.1	$384.8	$(354.4) (b)	$71,197.3
Accumulated Depreciation and Amortization	13,703.3	3,856.7	244.3	40.1	183.6	(186.4) (b)	17,841.6
Total Property Plant and Equipment - Net	$30,850.1	$13,762.4	$7,886.0	$824.0	$201.2	$(168.0) (b)	$53,355.7
Total Assets	$38,813.2	$16,399.1	$9,127.7	$2,369.3	$4,306.1 (c)	$(3,398.0) (b) (d)	$67,617.4
Long-term Debt Due Within One Year:							
Nonaffiliated	$1,306.1	$548.5	$50.0	$0.1	$(0.5)	$—	$1,904.2
Long-term Debt:							
Affiliated	50.0	—	—	32.2	—	(82.2)	—
Nonaffiliated	11,563.5	5,082.2	2,966.2	(0.3)	1,258.2	—	20,869.8
Total Long-term Debt	$12,919.6	$5,630.7	$3,016.2	$32.0	$1,257.7	$(82.2)	$22,774.0

	December 31, 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	$43,294.4	$16,371.2	$7,110.2	$644.6	$374.5	$(366.4) (b)	$67,428.5
Accumulated Depreciation and Amortization	13,153.4	3,768.3	176.6	75.0	180.6	(186.9) (b)	17,167.0
Total Property Plant and Equipment - Net	$30,141.0	$12,602.9	$6,933.6	$569.6	$193.9	$(179.5) (b)	$50,261.5
Total Assets	$37,579.7	$16,060.7	$8,141.8	$2,009.8	$3,959.1 (c)	$(3,022.0) (b) (d)	$64,729.1
Long-term Debt Due Within One Year:							
Nonaffiliated	$1,038.1	$663.1	$50.0	$—	$2.5	$—	$1,753.7
Long-term Debt:							
Affiliated	50.0	—	—	32.2	—	(82.2)	—

Nonaffiliated	10,801.4	4,705.4	2,631.3	(0.3)	1,281.8	—	19,419.6
Total Long-term Debt	$ 11,889.5	$ 5,368.5	$ 2,681.3	$ 31.9	$ 1,284.3	$ (82.2)	$ 21,173.3

(a) Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
(b) Includes eliminations due to an intercompany capital lease.
(c) Includes elimination of AEP Parent's investments in wholly-owned subsidiary companies.
(d) Reconciling Adjustments for Total Assets primarily include elimination of intercompany advances to affiliates and intercompany accounts receivable.

Registrant Subsidiaries' Reportable Segments (Applies to all Registrant Subsidiaries except AEPTCo)

The Registrant Subsidiaries each have one reportable segment, an integrated electricity generation, transmission and distribution business for APCo, I&M, PSO and SWEPCo, and an integrated electricity transmission and distribution business for AEP Texas and OPCo. Other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

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 RTOs 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 the 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 Transcos 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, 2018 and 2017 and reportable segment balance sheet information as of September 30, 2018 and December 31, 2017.

	Three Months Ended September 30, 2018			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$46.0	$ —	$ —	$ 46.0
Sales to AEP Affiliates	148.4	—	—	148.4
Other Revenues	—	—	—	—
Total Revenues	$194.4	$ —	$ —	$ 194.4
Interest Income	$0.2	$ 26.0	$ (25.7) (b)	$ 0.5
Interest Expense	19.8	25.7	(25.7) (b)	19.8
Income Tax Expense	18.4	(0.8)	—	17.6
Net Income	$77.1	$ 1.0 (c)	$ —	$ 78.1

	Three Months Ended September 30, 2017			
	State Transcos (a)	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated (a)
	(in millions)			
Revenues from:				
External Customers	$35.6	$ —	$ —	$ 35.6
Sales to AEP Affiliates	130.1	—	—	130.1
Other Revenues	(0.1)	—	—	(0.1)
Total Revenues	$165.6	$ —	$ —	$ 165.6
Interest Income	$—	$ 19.5	$ (19.3) (b)	$ 0.2
Interest Expense	17.1	19.3	(19.3) (b)	17.1
Income Tax Expense	29.5	—	—	29.5

Net Income	$58.5	$ 0.1	(c)$ —	$ 58.6

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	Nine Months Ended September 30, 2018			
	State Transcos (a)	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated (a)
	(in millions)			
Revenues from:				
External Customers	$132.3	$ —	$ —	$ 132.3
Sales to AEP Affiliates	453.8	—	—	453.8
Other Revenues	0.1	$ —	$ —	0.1
Total Revenues	$586.2	$ —	$ —	$ 586.2
Interest Income	$0.4	$ 76.2	$ (75.3) (b)	$ 1.3
Interest Expense	60.7	75.3	(75.3) (b)	60.7
Income Tax Expense	63.7	—	—	63.7
Net Income	$243.6	$ 0.6 (c)	$ —	$ 244.2

	Nine Months Ended September 30, 2017			
	State Transcos (a)	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated (a)
	(in millions)			
Revenues from:				
External Customers	$95.7	$ —	$ —	$ 95.7
Sales to AEP Affiliates	439.1	—	—	439.1
Other Revenues	—	—	—	—
Total Revenues	$534.8	$ —	$ —	$ 534.8
Interest Income	$0.1	$ 58.0	$ (57.6) (b)	$ 0.5
Interest Expense	50.4	57.6	(57.6) (b)	50.4
Income Tax Expense	108.0	0.2	—	108.2
Net Income	$212.1	$ 0.3 (c)	$ —	$ 212.4

	September 30, 2018			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Total Transmission Property	$7,761.6 (a)	$—	$ —	$ 7,761.6 (a)
Accumulated Depreciation and Amortization	234.6 (a)	—	—	234.6 (a)
Total Transmission Property – Net	$7,527.0 (a)	$—	$ —	$ 7,527.0 (a)
Notes Receivable - Affiliated	$—	$2,900.0	$ (2,900.0) (d)	$ —
Total Assets	$7,983.6 (a)	$2,988.4 (e)	$ (2,973.6) (f)	$ 7,998.4 (a)
Total Long-term Debt	$2,900.0	$2,872.6	$ (2,900.0) (d)	$ 2,872.6

	December 31, 2017			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			

Total Transmission Property	$6,770.5	(a)	$—		$—		$ 6,770.5	(a)
Accumulated Depreciation and Amortization	152.6	(a)	—		—		152.6	(a)
Total Transmission Property – Net	$6,617.9	(a)	$—		$—		$ 6,617.9	(a)
Notes Receivable - Affiliated	$—		$2,550.4		$ (2,550.4	) (d)	$ —	
Total Assets	$7,086.9	(a)	$2,590.1	(e)	$ (2,594.9	) (f)	$ 7,082.1	(a)
Total Long-term Debt	$2,575.0		$2,550.4		$ (2,575.0	) (d)	$ 2,550.4	

(a) The amounts presented reflect the revisions made to AEPTCo's previously issued financial statements. For additional details on revisions made to AEPTCo's financial statements, see Note 1- Significant Accounting Matters.
(b) Elimination of intercompany interest income/interest expense on affiliated debt arrangement.
(c) Includes the elimination of AEPTCo Parent's equity earnings in the State Transcos.
(d) Elimination of intercompany debt.
(e) Includes the elimination of AEPTCo Parent's investments in State Transcos.
(f) Primarily relates to the elimination of Notes Receivable from the State Transcos.

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.

The Registrants adopted ASU 2017-12 in the second quarter of 2018, effective January 1, 2018. See Note 2 - New Accounting Pronouncements for additional information.

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

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

The Registrants are exposed to certain market risks as major power producers and participants in the electricity, capacity, natural gas, coal and emission allowance markets. These risks include commodity price risks which may be subject to capacity risk, interest rate risk, credit risk and 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, 2018

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
		(in millions)						
Commodity:								
Power	MWhs	415.7	—	88.7	52.8	8.0	19.0	13.0
Coal	Tons	0.2	—	—	0.2	—	—	—
Natural Gas	MMBtus	84.4	—	8.4	4.9	—	—	16.1
Heating Oil and Gasoline	Gallons	8.3	1.7	1.6	0.8	2.0	0.8	0.9
Interest Rate	USD	$37.7	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate	USD	$500.0	$ —	$ —	$ —	$ —	$ —	$ —

Notional Volume of Derivative Instruments
December 31, 2017

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
		(in millions)						
Commodity:								
Power	MWhs	358.7	—	57.4	38.5	10.4	10.3	22.7
Coal	Tons	2.0	—	—	2.0	—	—	—
Natural Gas	MMBtus	53.7	—	1.1	0.7	—	—	18.3
Heating Oil and Gasoline	Gallons	6.9	1.4	1.3	0.7	1.6	0.7	0.8
Interest Rate	USD	$50.7	$ —	$ —	$ —	$ —	$ —	$ —
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. AEP netted cash collateral received from third parties against short-term and long-term risk management assets in the amounts of $15 million and $9.4 million as of September 30, 2018 and December 31, 2017, respectively. AEP netted cash collateral paid to third parties against short-term and long-term risk management liabilities in the amounts of $1 million and $9 million as of September 30, 2018 and December 31, 2017, respectively. The netted cash collateral from third parties against short-term and long-term risk management assets and netted cash collateral paid to third parties against short-term and long-term risk management liabilities were immaterial for the other Registrants as of September 30, 2018 and December 31, 2017.

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, 2018

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	$359.9	$29.1	$—	$ 389.0	$(197.1)	$ 191.9
Long-term Risk Management Assets	295.3	10.6	—	305.9	(41.0)	264.9
Total Assets	655.2	39.7	—	694.9	(238.1)	456.8
Current Risk Management Liabilities	232.4	7.5	0.5	240.4	(183.1)	57.3
Long-term Risk Management Liabilities	240.0	55.4	33.7	329.1	(41.9)	287.2
Total Liabilities	472.4	62.9	34.2	569.5	(225.0)	344.5
Total MTM Derivative Contract Net Assets (Liabilities)	$182.8	$(23.2)	$(34.2)	$ 125.4	$(13.1)	$ 112.3

Fair Value of Derivative Instruments
December 31, 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	$389.0	$17.5	$2.5	$ 409.0	$(282.8)	$ 126.2
Long-term Risk Management Assets	300.9	6.3	—	307.2	(25.1)	282.1
Total Assets	689.9	23.8	2.5	716.2	(307.9)	408.3
Current Risk Management Liabilities	334.6	9.0	—	343.6	(282.0)	61.6
Long-term Risk Management Liabilities	280.6	58.3	8.6	347.5	(25.5)	322.0
Total Liabilities	615.2	67.3	8.6	691.1	(307.5)	383.6
Total MTM Derivative Contract Net Assets (Liabilities)	$74.7	$(43.5)	$(6.1)	$ 25.1	$(0.4)	$ 24.7

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AEP Texas
Fair Value of Derivative Instruments
September 30, 2018

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	$ 0.5	$ —	$ 0.5
Long-term Risk Management Assets	—	—	—
Total Assets	0.5	—	0.5
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets	$ 0.5	$ —	$ 0.5

Fair Value of Derivative Instruments
December 31, 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	$ 0.5	$ —	$ 0.5
Long-term Risk Management Assets	—	—	—
Total Assets	0.5	—	0.5
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets	$ 0.5	$ —	$ 0.5

APCo
Fair Value of Derivative Instruments
September 30, 2018
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	$106.6	$ (38.2)	$ 68.4
Long-term Risk Management Assets	6.0	(4.6)	1.4
Total Assets	112.6	(42.8)	69.8
Current Risk Management Liabilities	39.1	(38.2)	0.9
Long-term Risk Management Liabilities	5.5	(4.8)	0.7
Total Liabilities	44.6	(43.0)	1.6
Total MTM Derivative Contract Net Assets	$68.0	$ 0.2	$ 68.2

Fair Value of Derivative Instruments
December 31, 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	$75.6	$ (50.7)	$ 24.9
Long-term Risk Management Assets	2.4	(1.3)	1.1
Total Assets	78.0	(52.0)	26.0
Current Risk Management Liabilities	50.6	(49.3)	1.3
Long-term Risk Management Liabilities	1.4	(1.2)	0.2
Total Liabilities	52.0	(50.5)	1.5
Total MTM Derivative Contract Net Assets (Liabilities)	$26.0	$ (1.5)	$ 24.5

I&M
Fair Value of Derivative Instruments
September 30, 2018

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	$39.4	$ (28.5)	$ 10.9
Long-term Risk Management Assets	3.7	(2.8)	0.9
Total Assets	43.1	(31.3)	11.8
Current Risk Management Liabilities	35.2	(28.8)	6.4
Long-term Risk Management Liabilities	3.2	(2.8)	0.4
Total Liabilities	38.4	(31.6)	6.8
Total MTM Derivative Contract Net Assets	$4.7	$ 0.3	$ 5.0

Fair Value of Derivative Instruments
December 31, 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	$47.2	$ (39.6)	$ 7.6
Long-term Risk Management Assets	1.6	(0.9)	0.7
Total Assets	48.8	(40.5)	8.3
Current Risk Management Liabilities	48.5	(45.0)	3.5
Long-term Risk Management Liabilities	0.9	(0.8)	0.1
Total Liabilities	49.4	(45.8)	3.6
Total MTM Derivative Contract Net Assets (Liabilities)	$(0.6)	$ 5.3	$ 4.7

OPCo
Fair Value of Derivative Instruments
September 30, 2018
Balance Sheet Location

	Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$0.6	$ —	$ 0.6
Long-term Risk Management Assets	0.1	—	0.1
Total Assets	0.7	—	0.7
Current Risk Management Liabilities	5.4	—	5.4
Long-term Risk Management Liabilities	89.8	—	89.8
Total Liabilities	95.2	—	95.2
Total MTM Derivative Contract Net Liabilities	$(94.5)	$ —	$ (94.5)

Fair Value of Derivative Instruments
December 31, 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	$0.6	$ —	$ 0.6
Long-term Risk Management Assets	—	—	—
Total Assets	0.6	—	0.6
Current Risk Management Liabilities	6.4	—	6.4
Long-term Risk Management Liabilities	126.0	—	126.0
Total Liabilities	132.4	—	132.4
Total MTM Derivative Contract Net Liabilities	$(131.8)	$ —	$ (131.8)

PSO
Fair Value of Derivative Instruments
September 30, 2018

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	$18.8	$ (0.3)	$ 18.5
Long-term Risk Management Assets	—	—	—
Total Assets	18.8	(0.3)	18.5
Current Risk Management Liabilities	0.9	(0.3)	0.6
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.9	(0.3)	0.6
Total MTM Derivative Contract Net Assets	$17.9	$ —	$ 17.9

Fair Value of Derivative Instruments
December 31, 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	$6.6	$ (0.2)	$ 6.4
Long-term Risk Management Assets	—	—	—
Total Assets	6.6	(0.2)	6.4
Current Risk Management Liabilities	0.2	(0.2)	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.2	(0.2)	—
Total MTM Derivative Contract Net Assets	$6.4	$ —	$ 6.4

SWEPCo
Fair Value of Derivative Instruments
September 30, 2018
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	$8.1	$ (1.6)	$ 6.5
Long-term Risk Management Assets	—	—	—
Total Assets	8.1	(1.6)	6.5
Current Risk Management Liabilities	1.8	(1.6)	0.2
Long-term Risk Management Liabilities	2.6	—	2.6
Total Liabilities	4.4	(1.6)	2.8
Total MTM Derivative Contract Net Assets	$3.7	$ —	$ 3.7

Fair Value of Derivative Instruments
December 31, 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	$7.0	$ (0.6)	$ 6.4
Long-term Risk Management Assets	—	—	—
Total Assets	7.0	(0.6)	6.4
Current Risk Management Liabilities	0.8	(0.6)	0.2
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.8	(0.6)	0.2
Total MTM Derivative Contract Net Assets	$6.2	$ —	$ 6.2

(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) All derivative contracts subject to a master netting arrangement or similar agreement are 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, 2018

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$(0.7)	$ —	$—	$—	$—	$—	$ —
Generation & Marketing Revenues	19.3	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(0.5)	(0.1)	—	—	—
Purchased Electricity for Resale	0.3	—	0.3	—	—	—	—
Other Operation	0.5	0.1	0.1	0.1	0.1	0.1	0.1
Maintenance	0.6	0.1	0.1	0.1	0.1	0.1	0.1
Regulatory Assets (a)	(14.0)	—	—	(3.5)	(9.3)	(0.6)	(0.6)
Regulatory Liabilities (a)	33.8	—	24.0	—	—	3.9	1.5
Total Gain (Loss) on Risk Management Contracts	$39.8	$ 0.2	$24.0	$(3.4)	$(9.1)	$3.5	$ 1.1

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

Location of Gain (Loss)	AEP	AEP Texas	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	—	—	0.1	—	—
Maintenance	0.1	0.1	0.1	—	0.1	—	—
Regulatory Assets (a)	(8.8)	0.1	0.1	(0.8)	(8.7)	—	0.3
Regulatory Liabilities (a)	15.6	0.1	3.7	2.1	—	2.6	7.0
Total Gain (Loss) on Risk Management Contracts	$26.6	$ 0.4	$ 4.5	$2.1	$(8.5)	$2.6	$ 7.2

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Nine Months Ended September 30, 2018

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$(9.4)	$ —	$—	$—	$—	$—	$ —
Generation & Marketing Revenues	31.7	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(1.3)	(7.8)	—	—	0.1
Purchased Electricity for Resale	8.3	—	7.3	0.8	—	—	—
Other Operation	1.3	0.3	0.2	0.2	0.3	0.2	0.2
Maintenance	1.5	0.3	0.3	0.2	0.3	0.2	0.2
Regulatory Assets (a)	29.2	—	—	(0.3)	31.8	(0.6)	(1.7)
Regulatory Liabilities (a)	206.2	—	127.3	11.7	0.6	34.8	7.6
Total Gain on Risk Management Contracts	$268.8	$ 0.6	$133.8	$4.8	$33.0	$34.6	$ 6.4

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

Location of Gain (Loss)	AEP	AEP Texas	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	—	—	0.1	—	—
Maintenance	0.4	0.1	0.1	—	0.1	—	—
Regulatory Assets (a)	(26.8)	—	—	(1.0)	(25.9)	—	0.1
Regulatory Liabilities (a)	81.8	(0.2)	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

(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 impacts recognized on the balance sheets related to the hedged items in fair value hedging relationships:

	Carrying Amount of the Hedged Assets/(Liabilities)		Cumulative Amount of Fair Value Hedging Adjustment Included in the Carrying Amount of the Hedged Assets/(Liabilities)	
	September 30, 2018	December 31, 2017	September 30, 2018	December 31, 2017
	(in millions)			
Long-Term Debt (a)	$(461.4)	$(489.3)	$ 34.2	$ 6.1

(a) Amounts included on the balance sheets within Long-term Debt Due within One Year and Long-term Debt, respectively.

The pretax effects of fair value hedge accounting on income were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Gain (Loss) on Interest Rate Contracts:				
Gain (Loss) on Fair Value Hedging Instruments (a)	$(6.3)	$0.1	$(28.1)	$(0.1)
Gain (Loss) on Fair Value Portion of Long-term Debt (a)	6.3	(0.1)	28.1	0.1

(a) Gain (Loss) is included in Interest Expense on the statements of income.

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 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.

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, 2018 and 2017, AEP applied cash flow hedging to outstanding power derivatives. During the three and nine months ended September 30, 2018 and 2017, 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, 2018 and 2017, AEP applied cash flow hedging to outstanding interest rate derivatives. During the three and nine months ended September 30, 2017, the Registrant Subsidiaries did not apply cash flow hedging to outstanding interest rate derivatives. During the three and nine months ended September 30, 2018 SWEPCo applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not.

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, 2018 and 2017, the Registrants did not apply cash flow hedging to any outstanding foreign currency derivatives.

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 - Comprehensive Income.

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, 2018		December 31, 2017	
	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)			
AOCI Loss Net of Tax	$(22.8)	$(12.7)	$(28.4)	$(13.0)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	14.4	(0.8)	5.5	(0.8)

As of September 30, 2018 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 183 months.

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

	September 30, 2018		December 31, 2017	
	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)			
AEP Texas	$(4.6)	$ (1.1)	$(4.5)	$ (0.9)
APCo	2.0	0.9	2.2	0.7
I&M	(11.9)	(1.6)	(10.7)	(1.3)
OPCo	1.3	1.3	1.9	1.1
PSO	2.4	1.0	2.6	0.8
SWEPCo	(3.7)	(1.5)	(6.0)	(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 credit agency ratings 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. The Registrants 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, 2018 and December 31, 2017, respectively.

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

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, 2018		
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	$ 253.1	$ 0.8	$ 211.2
APCo	0.1	—	0.1
I&M	—	—	—
SWEPCo	2.8	—	2.8

	December 31, 2017		
	Liabilities for Contracts with Cross Default Provisions		Additional Settlement Liability if Cross

Company	Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Default Provision is Triggered
	(in millions)		
AEP	$243.6	$ 1.3	$ 223.1
APCo	0.6	—	0.5
I&M	0.4	—	0.4
SWEPCo	0.2	—	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 benefit plan and 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. 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, 2018 Book Value	Fair Value	December 31, 2017 Book Value	Fair Value
	(in millions)			
AEP	$22,774.0	$23,869.1	$21,173.3	$23,649.6
AEP Texas	3,914.4	4,019.2	3,649.3	3,964.8
AEPTCo	2,872.6	2,861.1	2,550.4	2,782.9
APCo	4,061.7	4,629.8	3,980.1	4,782.6
I&M	3,062.4	3,161.9	2,745.1	3,014.7
OPCo	1,716.3	1,941.9	1,719.3	2,064.3
PSO	1,286.9	1,373.4	1,286.5	1,457.1
SWEPCo	3,072.7	3,068.4	2,441.9	2,645.9

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

Other Temporary Investments include 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, 2018 Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash and Other Cash Deposits (a)	$170.4	$ —	$ —	$170.4
Fixed Income Securities – Mutual Funds (b)	105.9	—	(2.8)	103.1
Equity Securities – Mutual Funds	17.6	22.2	—	39.8
Total Other Temporary Investments	$293.9	$ 22.2	$ (2.8)	$313.3

Other Temporary Investments	December 31, 2017 Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash and Other Cash Deposits (a)	$220.1	$ —	$ —	$220.1
Fixed Income Securities – Mutual Funds (b)	104.3	—	(1.4)	102.9
Equity Securities – Mutual Funds	17.0	19.7	—	36.7
Total Other Temporary Investments	$341.4	$ 19.7	$ (1.4)	$359.7

(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.

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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,	
	2018	2017	2018	2017
	(in millions)			
Proceeds from Investment Sales	$ —	$ —	$ —	$ —
Purchases of Investments	0.8	12.6	2.2	13.6
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, see Note 3 - Comprehensive Income.

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 SNF 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. Upon adoption of ASU 2016-01 in first quarter 2018, equity securities are now recorded with changes in fair value recognized in earnings. Effective January 2018 available for sale classification only applies to investment in debt securities. Other-than-temporary impairments for investments in debt 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, unrealized losses 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.

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The following is a summary of nuclear trust fund investments:

	September 30, 2018			December 31, 2017		
	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$41.6	$ —	$ —	$17.2	$ —	$ —
Fixed Income Securities:						
United States Government	951.9	12.2	(6.2)	981.2	29.7	(3.6)
Corporate Debt	54.4	1.1	(1.6)	58.7	3.8	(1.2)
State and Local Government	8.5	0.5	(0.2)	8.8	0.8	(0.2)
Subtotal Fixed Income Securities	1,014.8	13.8	(8.0)	1,048.7	34.3	(5.0)
Equity Securities - Domestic (a)	1,609.6	990.5	—	1,461.7	868.2	(75.5)
Spent Nuclear Fuel and Decommissioning Trusts	$2,666.0	$ 1,004.3	$ (8.0)	$2,527.6	$ 902.5	$ (80.5)

(a) Amount reported as Gross Unrealized Gains includes unrealized gains of $995.8 million and unrealized losses of $5.3 million. AEP adopted ASU 2016-01 during the first quarter of 2018 by means of a modified retrospective approach. Due to the adoption of the ASU, Other-Than-Temporary Impairments are no longer applicable to Equity Securities with readily determinable fair values.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Proceeds from Investment Sales	$513.1	$519.5	$1,550.9	$1,808.6
Purchases of Investments	521.2	525.0	1,589.0	1,842.2
Gross Realized Gains on Investment Sales	3.9	9.8	27.7	198.1
Gross Realized Losses on Investment Sales	3.5	5.2	22.2	145.4

The base cost of fixed income securities was $1 billion and $1 billion as of September 30, 2018 and December 31, 2017, respectively. The base cost of equity securities was $619 million and $594 million as of September 30, 2018 and December 31, 2017, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of September 30, 2018 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 348.7
After 1 year through 5 years	331.4
After 5 years through 10 years	177.0
After 10 years	157.7
Total	$ 1,014.8

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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, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	$160.8	$—	$—	$9.6	$170.4
Fixed Income Securities – Mutual Funds	103.1	—	—	—	103.1
Equity Securities – Mutual Funds (b)	39.8	—	—	—	39.8
Total Other Temporary Investments	303.7	—	—	9.6	313.3
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	1.7	270.9	361.7	(213.2)	421.1
Cash Flow Hedges:					
Commodity Hedges (c)	—	20.9	11.7	3.1	35.7
Total Risk Management Assets	1.7	291.8	373.4	(210.1)	456.8
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	27.2	—	—	14.4	41.6
Fixed Income Securities:					
United States Government	—	951.9	—	—	951.9
Corporate Debt	—	54.4	—	—	54.4
State and Local Government	—	8.5	—	—	8.5
Subtotal Fixed Income Securities	—	1,014.8	—	—	1,014.8
Equity Securities – Domestic (b)	1,609.6	—	—	—	1,609.6
Total Spent Nuclear Fuel and Decommissioning Trusts	1,636.8	1,014.8	—	14.4	2,666.0
Total Assets	$1,942.2	$1,306.6	$373.4	$(186.1)	$3,436.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$1.9	$271.4	$178.2	$(200.1)	$251.4
Cash Flow Hedges:					
Commodity Hedges (c)	—	21.8	34.0	3.1	58.9
Fair Value Hedges	—	34.2	—	—	34.2

Total Risk Management Liabilities	$1.9	$327.4	$212.2	$(197.0)	$344.5

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AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	$183.2	$—	$—	$36.9	$220.1
Fixed Income Securities – Mutual Funds	102.9	—	—	—	102.9
Equity Securities – Mutual Funds (b)	36.7	—	—	—	36.7
Total Other Temporary Investments	322.8	—	—	36.9	359.7
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	3.9	391.2	274.1	(285.4)	383.8
Cash Flow Hedges:					
Commodity Hedges (c)	—	17.3	4.7	—	22.0
Fair Value Hedges	—	2.5	—	—	2.5
Total Risk Management Assets	3.9	411.0	278.8	(285.4)	408.3
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	7.5	—	—	9.7	17.2
Fixed Income Securities:					
United States Government	—	981.2	—	—	981.2
Corporate Debt	—	58.7	—	—	58.7
State and Local Government	—	8.8	—	—	8.8
Subtotal Fixed Income Securities	—	1,048.7	—	—	1,048.7
Equity Securities – Domestic (b)	1,461.7	—	—	—	1,461.7
Total Spent Nuclear Fuel and Decommissioning Trusts	1,469.2	1,048.7	—	9.7	2,527.6
Total Assets	$1,795.9	$1,459.7	$278.8	$(238.8)	$3,295.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$5.1	$392.5	$196.9	$(285.0)	$309.5
Cash Flow Hedges:					
Commodity Hedges (c)	—	23.9	41.6	—	65.5
Fair Value Hedges	—	8.6	—	—	8.6
Total Risk Management Liabilities	$5.1	$425.0	$238.5	$(285.0)	$383.6

AEP Texas

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Restricted Cash for Securitized Funding	$ 124.2	$ —	$ —	$ —	$ 124.2
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	0.5	—	—	0.5
Total Assets	$ 124.2	$ 0.5	$ —	$ —	$ 124.7

AEP Texas

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Restricted Cash for Securitized Funding	$ 155.2	$ —	$ —	$ —	$ 155.2
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	0.5	—	—	0.5
Total Assets	$ 155.2	$ 0.5	$ —	$ —	$ 155.7

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Restricted Cash for Securitized Funding	$9.9	$—	$—	$—	$9.9
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	0.2	41.8	66.7	(38.9)	69.8
Total Assets	$10.1	$41.8	$66.7	$(38.9)	$79.7
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$0.3	$40.2	$0.2	$(39.1)	$1.6

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Restricted Cash for Securitized Funding	$16.3	$—	$—	$—	$16.3
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	52.5	25.1	(51.6)	26.0
Total Assets	$16.3	$52.5	$25.1	$(51.6)	$42.3
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$51.2	$0.4	$(50.1)	$1.5

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$0.1	$28.5	$12.3	$(29.1)	$11.8
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	27.2	—	—	14.4	41.6
Fixed Income Securities:					
United States Government	—	951.9	—	—	951.9
Corporate Debt	—	54.4	—	—	54.4
State and Local Government	—	8.5	—	—	8.5
Subtotal Fixed Income Securities	—	1,014.8	—	—	1,014.8
Equity Securities - Domestic (b)	1,609.6	—	—	—	1,609.6
Total Spent Nuclear Fuel and Decommissioning Trusts	1,636.8	1,014.8	—	14.4	2,666.0
Total Assets	$1,636.9	$1,043.3	$12.3	$(14.7)	$2,677.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$0.1	$33.2	$2.9	$(29.4)	$6.8

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$—	$39.4	$9.1	$(40.2)	$8.3
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	7.5	—	—	9.7	17.2
Fixed Income Securities:					
United States Government	—	981.2	—	—	981.2
Corporate Debt	—	58.7	—	—	58.7
State and Local Government	—	8.8	—	—	8.8
Subtotal Fixed Income Securities	—	1,048.7	—	—	1,048.7
Equity Securities - Domestic (b)	1,461.7	—	—	—	1,461.7
Total Spent Nuclear Fuel and Decommissioning Trusts	1,469.2	1,048.7	—	9.7	2,527.6

Total Assets	$1,469.2	$1,088.1	$9.1	$(30.5)	$2,535.9
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$47.6	$1.5	$(45.5)	$3.6

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OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2018

Assets:	Level 1	Level 2	Level 3	Other	Total
	(in millions)				
Restricted Cash for Securitized Funding	$15.2	$—	$—	$—	$15.2
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	0.7	—	—	0.7
Total Assets	$15.2	$0.7	$—	$—	$15.9
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$—	$95.2	$—	$95.2

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

Assets:	Level 1	Level 2	Level 3	Other	Total
	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$—	$0.6	$—	$—	$0.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$—	$132.4	$—	$132.4

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PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$—	$0.3	$18.5	$(0.3)	$18.5
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$—	$0.9	$(0.3)	$0.6

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$—	$0.2	$6.4	$(0.2)	$6.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$—	$0.2	$(0.2)	$—

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SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$—	$0.2	$7.9	$(1.6)	$6.5
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$—	$4.4	$(1.6)	$2.8

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$—	$0.3	$6.7	$(0.6)	$6.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$—	$0.8	$(0.6)	$0.2

(a) Amounts in "Other'' column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.

(b) Amounts represent publicly traded equity securities and equity-based mutual funds.

(c) Amounts in "Other'' column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging.''

(d) The September 30, 2018 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 2 matures $(2) million in 2018 and $(2) million in periods 2019-2021 and $3 million in periods 2022-2023; Level 3 matures $40 million in 2018, $122 million in periods 2019-2021, $21 million in periods 2022-2023 and $1 million in periods 2024-2032. 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, 2017 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $(1) million in 2018; Level 2 matures $(3) million in 2018 and $2 million in periods 2022-2023; Level 3 matures $59 million in 2018, $33 million in periods 2019-2021, $14 million in periods 2022-2023 and $(29) million in periods 2024-2032. 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, 2018 and 2017.

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, 2018	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of June 30, 2018	$172.3	$60.0	$13.2	$(86.9)	$24.3	$ 4.9
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	19.9	9.0	1.9	—	3.7	1.7
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	1.5	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	10.4	—	—	—	—	—
Settlements	(56.0)	(19.8)	(5.5)	0.6	(10.8)	(2.7)
Transfers into Level 3 (c) (d)	2.3	—	—	—	—	—
Transfers out of Level 3 (d)	(1.2)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	12.0	17.3	(0.2)	(8.9)	0.4	(0.4)
Balance as of September 30, 2018	$161.2	$66.5	$9.4	$(95.2)	$17.6	$ 3.5

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) (a) (b)	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 (a)	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 (c) (d)	5.7	—	—	—	—	—
Transfers out of Level 3 (d)	0.2	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	(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

Nine Months Ended September 30, 2018	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of December 31, 2017	$40.3	$24.7	$7.6	$(132.4)	$6.2	$ 5.9
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	150.9	104.4	14.7	1.3	18.1	(4.8)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	9.5	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	16.4	—	—	—	—	—
Settlements	(212.3)	(128.3)	(21.9)	3.0	(24.3)	(1.3)
Transfers into Level 3 (c) (d)	16.5	—	—	—	—	—
Transfers out of Level 3 (d)	(2.5)	—	(0.3)	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	142.4	65.7	9.3	32.9	17.6	3.7
Balance as of September 30, 2018	$161.2	$66.5	$9.4	$(95.2)	$17.6	$ 3.5

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) (a) (b)	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 (a)	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 (c) (d)	16.1	—	—	—	—	—
Transfers out of Level 3 (d)	(9.1)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	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

(a) Included in revenues on the statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents existing assets or liabilities that were previously categorized as Level 2.
(d) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(e) 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, 2018
AEP

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$251.5	$ 202.4	Discounted Cash Flow	Forward Market Price (a)	$(0.05)	$161.90	$ 33.54
				Counterparty Credit Risk (b)	10	418	158
Natural Gas Contracts	—	2.8	Discounted Cash Flow	Forward Market Price (c)	2.19	2.97	2.45
FTRs	121.9	7.0	Discounted Cash Flow	Forward Market Price (a)	(9.40)	16.17	0.83
Total	$373.4	$ 212.2					

Significant Unobservable Inputs
December 31, 2017
AEP

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$225.1	$ 233.7	Discounted Cash Flow	Forward Market Price (a)	$(0.05)	$263.00	$ 36.32
				Counterparty Credit Risk (b)	8	456	180
Natural Gas Contracts	—	0.2	Discounted Cash Flow	Forward Market Price (c)	2.37	2.96	2.62
FTRs	53.7	4.6	Discounted Cash Flow	Forward Market Price (a)	(55.62)	54.88	0.41
Total	$278.8	$ 238.5					

Significant Unobservable Inputs
September 30, 2018
APCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$1.8	$ 0.1	Discounted Cash Flow	Forward Market Price	$14.98	$59.45	$ 36.30
FTRs	64.9	0.1	Discounted Cash Flow	Forward Market Price	0.06	12.73	2.37
Total	$66.7	$ 0.2					

Significant Unobservable Inputs
December 31, 2017
APCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$0.8	$ 0.4	Discounted Cash Flow	Forward Market Price	$20.52	$195.00	$ 33.80
FTRs	24.3	—	Discounted Cash Flow	Forward Market Price	(0.36)	7.15	1.62
Total	$25.1	$ 0.4					

Significant Unobservable Inputs
September 30, 2018
I&M

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$1.1	$ 0.9	Discounted Cash Flow	Forward Market Price	$14.98	$59.45	$ 36.30
FTRs	11.2	2.0	Discounted Cash Flow	Forward Market Price	(2.58)	6.21	0.73
Total	$12.3	$ 2.9					

Significant Unobservable Inputs
December 31, 2017
I&M

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$0.5	$ 0.3	Discounted Cash Flow	Forward Market Price	$20.52	$195.00	$ 33.80
FTRs	8.6	1.2	Discounted Cash Flow	Forward Market Price	(0.36)	5.75	0.86
Total	$9.1	$ 1.5					

Significant Unobservable Inputs
September 30, 2018
OPCo

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range High	Weighted Average
	(in millions)						
Energy Contracts	$ —	$ 95.2	Discounted Cash Flow	Forward Market Price (a)	$ 27.23	$ 64.61	$ 43.26
				Counterparty Credit Risk (b)	10	188	141
Total	$ —	$ 95.2					

Significant Unobservable Inputs
December 31, 2017
OPCo

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range High	Weighted Average
	(in millions)						
Energy Contracts	$ —	$ 132.4	Discounted Cash Flow	Forward Market Price (a)	$ 30.52	$ 170.43	$ 44.62
				Counterparty Credit Risk (b)	8	190	136
Total	$ —	$ 132.4					

Significant Unobservable Inputs
September 30, 2018
PSO

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Input/Range Low	Input/Range High	Weighted Average
	(in millions)						
FTRs	$ 18.5	$ 0.9	Discounted Cash Flow	Forward Market Price	$ (9.40)	$ 10.30	$ (1.49)

Significant Unobservable Inputs
December 31, 2017
PSO

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Input/Range Low	Input/Range High	Weighted Average
	(in millions)						
FTRs	$ 6.4	$ 0.2	Discounted Cash Flow	Forward Market Price	$ (6.62)	$ 1.41	$ (0.76)

Significant Unobservable Inputs
September 30, 2018
SWEPCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input	Low	High	Weighted Average
	(in millions)						
Natural Gas Contracts	$—	$ 2.8	Discounted Cash Flow	Forward Market Price (c)	$2.19	$2.97	$ 2.45
FTRs	7.9	1.6	Discounted Cash Flow	Forward Market Price (a)	(9.40)	10.30	(1.49)
Total	$7.9	$ 4.4					

Significant Unobservable Inputs
December 31, 2017
SWEPCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input	Low	High	Weighted Average
	(in millions)						
Natural Gas Contracts	$—	$ 0.2	Discounted Cash Flow	Forward Market Price (c)	$2.37	$2.96	$ 2.62
FTRs	6.7	0.6	Discounted Cash Flow	Forward Market Price (a)	(6.62)	1.41	(0.76)
Total	$6.7	$ 0.8					

(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, 2018 and December 31, 2017:

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.

Federal Tax Reform

In December 2017, Tax Reform legislation was signed into law. Tax Reform includes significant changes to the Internal Revenue Code of 1986, as amended, and had a m