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.

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

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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.

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

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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 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,		Nine Months Ended September 30,	
	2018	2017	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,		Nine Months Ended September 30,	
	2018	2017	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.

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

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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 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.

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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.

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					